OFFERING MEMORANDUM **STRICTLY CONFIDENTIAL**

US$403,900,000

LATIN AMERICA POWER

Inversiones Latin América Power Ltda.

5.125% SENIOR SECURED NOTES DUE 2033

Guaranteed by San Juan S.A. and Norvind S.A.

Inversiones Latin América Power Ltda., a limited liability company (*sociedad de responsabilidad limitada*) formed under the laws of Chile (the "*Issuer*" or "*ILAP*"), will issue US$403,900,000 aggregate principal amount of senior secured notes due 2033 (the "*Notes*"). The Notes will be fully and unconditionally, jointly and severally, guaranteed (the "*Note Guarantees*") by San Juan S.A. ("*San Juan*") and Norvind S.A. ("*Norvind*," and together with San Juan, the "*Guarantors*"). The Issuer will pay interest on the Notes semi-annually in arrears on January 3 and July 3 of each year, commencing on January 3, 2022. Principal on the Notes will be payable semi-annually on the same date as interest, commencing on January 3, 2022, as described in this offering memorandum. The final maturity of the notes is June 15, 2033.

The Notes may be redeemed, at the Issuer's option, in whole or in part, on any date prior to July 3, 2028 at a redemption price based on a "make-whole" premium and, on or after July 3, 2028, at the fixed redemption prices described in this offering memorandum. Upon certain eligible equity offerings and prior to July 3, 2024, the Issuer may, at its discretion, redeem up to 35% of the aggregate principal amount of the outstanding Notes at a redemption price equal to 105.125% of the principal amount on the redemption date. On every scheduled payment date, and to the extent of Available Cash (as defined herein), the Issuer will be required to redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed based on a Target Debt Balance (as defined herein) amount as of the date of determination, without premium. See "*Description of the Notes—Cash Sweep Mandatory Redemption*". Upon the occurrence of a change of control or certain events of loss, dispositions and other events described herein, the Issuer will be required to offer to purchase the Notes at the applicable prices set forth in this offering memorandum. In addition, if certain changes in applicable tax law occur, the Issuer may redeem the Notes, in whole but not in part, at a redemption price equal to 100% of the principal amount of the Notes being redeemed without premium, plus accrued and unpaid interest to, but excluding, the redemption date, plus any additional amounts.

The Notes and the Note Guarantees will be the senior obligations of the Issuer and the Guarantors, will rank equally in right of payment with all of the Issuer's and the Gurantors' existing and future senior indebtedness, effectively senior to any existing and future unsecured indebtedness (to the extent of the value of the collateral securing the Notes and the Note Guarantees) and senior to any of the Issuer's or the Guarantors' future subordinated indebtedness. The Notes will be secured, subject to certain Permitted Liens (as described herein), by a first priority security interest over substantially all assets of the Issuer and the Guarantors, as described in this offering memorandum.

The Collateral securing the Notes and the Note Guarantees may also secure additional Notes in the future, subject to certain conditions described herein. The Note Guarantees and security interest will be subject to contractual and legal limitations under relevant local laws and may be released under certain limited circumstances.

On, before or after the Issue Date, the Issuer intends to enter into a Letter of Credit Facility Agreement (the "*LC Facility Agreement*") with Citibank, N.A. for purposes of issuing one or more standby letters of credit to fund the Debt Service Reserve Account and the O&M Reserve Account (as defined herein). The Issuer's obligations under the LC Facility Agreement would rank *pari passu* with the Notes, be secured ratably by the Collateral and be jointly and severally guaranteed by the Guarantors. See "*Description of the Notes*" for a description of certain intercreditor arrangements among the Secured Parties (as defined herein).

Investing in the Notes involves a significant degree of risk. See "*Risk Factors*" beginning on page 29.

Issue Price: 99.997%, plus accrued interest, if any, from June 15, 2021

The Notes have not been and will not be registered under the Securities Act, any state securities laws or the securities laws of any other jurisdiction. The Notes may not be offered or sold in the United States or to U.S. persons (as defined in Regulation S), except in transactions exempt from, or not subject to, the registration requirements of the Securities Act. Accordingly, the Notes are being offered and sold (i) to U.S. persons, only to or for the account of persons that are QIBs as defined in Rule 144A and (ii) to persons other than U.S. persons (as defined in Regulation S), in compliance with Regulation S. In addition, the Notes are subject to restrictions on transfer and resale as further described in "*Plan of Distribution*" and "*Transfer Restrictions*."

The Notes may not be publicly offered or sold, directly or indirectly, in Chile or to any resident in Chile, except as permitted by applicable Chilean law. The Notes will not be registered under Law No. 18,045, as amended (the "*Chilean Securities Market Law*"), with the Chilean Financial Market Commission (*Comisión para el Mercado Financiero*, or "*CMF*"), and, accordingly, the Notes may not and will not be offered or sold to persons in Chile except in circumstances which do not and will not result in a public offering under Chilean law, and in compliance with Rule (*Norma de Carácter General*) No. 336, dated June 27, 2012, issued by the CMF ("*CMF Rule 336*"). Pursuant to CMF Rule 336, the offering of the Notes that meets the conditions described therein shall not be considered public offerings in Chile, including that the offering is addressed to certain "qualified investors," identified as such therein (which in turn are further described in Rule No. 216, dated June 12, 2008, of the CMF), and shall be exempted from complying with the general rules applicable to public offerings. See "*Notice to Prospective Investors in Chile*."

Notification under Section 309B(1)(c) of the Securities and Futures Act, Chapter 289 of Singapore ("*SFA*")—The Notes are prescribed capital markets products as defined in the Securities and Futures (Capital Markets Products) Regulations 2018 of Singapore.

There is currently no public market for the Notes. Application will be made to the Singapore Exchange Trading Limited (the "*SGX-ST*") for the listing and quotation of the Notes on the Official List of the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any of the statements made, opinions expressed, or reports contained in this offering memorandum. Approval-in-principle from, admission of the Notes to the Official List of the SGX-ST or the listing or quotation of the Notes on the SGX-ST are not to be taken as an indication of the merits of the offering, the Issuer, the Guarantors, their respective subsidiaries or associated companies, if any, the Initial Purchasers (as defined herein), the Notes, or the Note Guarantees. The Notes will be issued in minimum denominations of US$200,000 each and integral multiples of US$1,000 in excess thereof. The Notes will be traded on the SGX-ST in a minimum board lot size of US$200,000 (or its equivalent in other currencies) for so long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require.

Delivery of the Notes will be made to investors in book-entry form through the facilities of The Depository Trust Company ("*DTC*") for the accounts of its direct and indirect participants, including Euroclear Bank S.A./N.V., as operator of the Euroclear System ("*Euroclear*"), and Clearstream Banking, *société anonyme* ("*Clearstream*"), on or about June 15, 2021 (the "*Issue Date*").

Global Coordinator

Goldman Sachs & Co. LLC

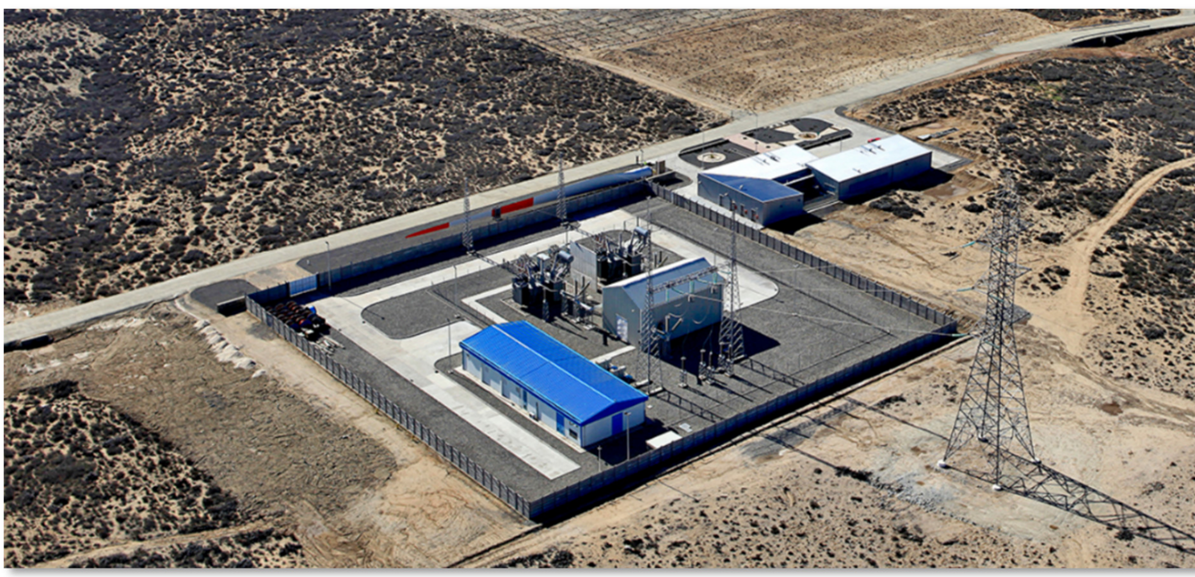
Joint Bookrunners

Citigroup **Goldman Sachs & Co. LLC**

The date of this Offering Memorandum is June 9, 2021.

Aerial view of San Juan wind farm.

San Juan Substation & control office.



Aerial view of Totoral wind farm.

Totoral control office.

TABLE OF CONTENTS

NOTICE TO INVESTORS

THE NOTES AND NOTE GUARANTEES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION ("*SEC*") OR ANY OTHER STATE SECURITIES COMMISSION OR OTHER REGULATORY AUTHORITY, AND NONE OF THE FOREGOING AUTHORITIES HAS CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS OFFERING MEMORANDUM. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE IN THE UNITED STATES.

IN CONNECTION WITH THE ISSUANCE OF THE NOTES, GOLDMAN SACHS & CO. LLC AND CITIGROUP GLOBAL MARKETS INC. (THE "*INITIAL PURCHASERS*") MAY OVER-ALLOT OR EFFECT TRANSACTIONS WITH A VIEW TO MAINTAINING THE MARKET PRICE OF THE NOTES AT A LEVEL ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL FOR A LIMITED PERIOD. HOWEVER, THERE IS NO OBLIGATION ON THE INITIAL PURCHASERS TO DO THIS. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME AND MUST BE BROUGHT TO AN END AFTER A LIMITED PERIOD. SUCH STABILIZING SHALL BE IN COMPLIANCE WITH ALL APPLICABLE LAWS, REGULATIONS AND RULES.

In this offering memorandum, unless the context otherwise requires:

- references to "*we*," "*us*", "*our*" or the "*Company*" mean, collectively, ILAP and the Guarantors,
- references to "*ILAP*" or the "*Issuer*", mean Inversiones Latin América Power Ltda.,
- references to the "*Guarantors*" mean, collectively, San Juan and Norvind,
- references to "*San Juan*" mean San Juan S.A., the owner and operator of the San Juan Project,
- references to "*Norvind*" mean Norvind S.A., the owner and operator of the Totoral Project,
- references to the "*Projects*" mean, collectively, the San Juan Project and the Totoral Project,
- references to the "*San Juan Project*" mean the wind project corresponding to the 193.2 MW facility located in Vallenar, Region of Atacama, Chile, and
- references to the "*Totoral Project*" mean the wind project corresponding to the 46.0 MW facility located in Canela, Region of Coquimbo, Chile.

This offering memorandum is highly confidential and has been prepared solely for use in connection with the proposed offering of the Notes described herein. This offering memorandum is personal to each offeree and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire the Notes. This offering memorandum may only be used for the purpose for which it has been prepared. Each prospective investor, by accepting delivery of this offering memorandum, agrees to the foregoing and to make no photocopies of this offering memorandum or any documents referred to in this offering memorandum. We reserve the right to withdraw this offering of the Notes at any time and we and the Initial Purchasers reserve the right to reject any commitment to purchase the Notes, in whole or in part, for any reason. The Initial Purchasers and certain related entities may acquire for their own account a portion of the Notes.

Each of the Initial Purchasers and the Indenture Trustee makes no representations (express or implied) in connection with, nor will any of them have any responsibility for, the contents of this offering memorandum. This offering memorandum contains summaries of certain documents, which summaries are believed to be accurate, but reference is made to the actual documents for complete information. All summaries are qualified in their entirety by such reference. Copies of certain documents referred to herein will be made available to prospective purchasers of the Notes, free of charge, upon request to the Issuer. See "*Available Information*."

None of the Issuer, the Guarantors, the Initial Purchasers or any of their respective affiliates has authorized any other person to provide you with different information or to make any representation not contained in this offering memorandum, and none of the Issuer, the Guarantors, the Initial Purchasers or any of their respective affiliates takes any responsibility for any other information that others may give to you. You should assume that the information contained in this offering memorandum is accurate only as of the date on the front cover of this offering memorandum (or such earlier date as may be specified in this offering memorandum). Neither the delivery of this offering memorandum nor any sale made hereunder will under any circumstance imply that the information contained herein is correct as of any date after the date of this offering memorandum (or such earlier date as may be specified in this offering memorandum).

The Initial Purchasers and their respective affiliates make no representation or warranty, express or implied, as to the accuracy or completeness of the information contained in this offering memorandum. You should not rely upon the information contained in this offering memorandum, as a promise or representation by the Initial Purchasers or any of their respective affiliates or advisors whether as to the past, present or future.

The Notes may not be offered or sold in the United States or to U.S. persons (as defined in Regulation S), except in transactions exempt from, or not subject to, the registration requirements of the Securities Act. Accordingly, the Notes are being offered and sold (i) to U.S. persons, only to or for the account of persons that are QIBs and (ii) to persons other than U.S. persons (as defined in Regulation S), in compliance with Regulation S.

Neither the Issuer, the Guarantors nor the Initial Purchasers is making an offer to sell the Notes in any jurisdiction except where an offer and sale is permitted. This offering memorandum is not an offer to sell, or a solicitation of anoffer to buy, the Notes and neither the Issuer, the Guarantors nor the Initial Purchasers is offering or soliciting an offer to buy the Notes in any jurisdiction where the offer, solicitation or sale would be unlawful or not permitted.

By purchasing Notes, you will be deemed to have made certain acknowledgments, representations and agreements as set forth under "*Transfer Restrictions*."

There is currently no market for the Notes and there can be no assurance that one will develop or, if one develops, that it will continue. You should be aware that you may be required to bear the financial risk of an investment in the Notes for an indefinite period of time. Application will be made to the SGX-ST for the listing and quotation of the Notes on the Official List of the SGX-ST. Approval-in-principle from the SGX-ST, admission of the Notes to the Official List of the SGX-ST and the listing and quotation of the Notes on the SGX-ST are not to be taken as an indication of the merits of the offering, Issuer, the Guarantors, their respective subsidiaries or associated companies, if any, the Notes, or the Note Guarantees. For so long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require, in the event that any Note issued in the form of a registered note in global form is exchanged for a note in physical, certificated form, the Issuer will appoint and maintain a paying agent in Singapore, where the certificated Notes may be presented or surrendered for payment or redemption. In addition, in the event that any Note issued in the form of a registered note in global form is exchanged for a note in physical, certificated form, an announcement of the exchange will be made by or on behalf of the Issuer through the SGX-ST and such announcement will include all material information with respect to the delivery of the certificated Notes, including details of the paying agent in Singapore. Any Notes traded on the SGX-ST will be traded in a minimum board lot size of US$200,000 (or its equivalent in foreign currencies) for so long as the Notes are listed and quoted on the SGX-ST and the rules of the SGX-ST so require.

In making an investment decision, you must rely on your own examination of the Issuer, the terms of the Notes and the terms of this offering, including the merits and risks involved.

None of the Issuer, the Guarantors, the Initial Purchasers or any of their respective affiliates or representatives, makes any representation to any purchaser of the Notes regarding the legality of an investment in the Notes by such purchaser under any legal investment or similar laws or regulations. You should not consider any information in this offering memorandum to be legal, business or tax advice. You should consult your own counsel, accountant, business advisor and tax advisor for legal, tax, business and financial advice regarding any investment in the Notes.

You must comply with all applicable laws and regulations in force in your jurisdiction and you must obtain any consent, approval or permission required by you for the purchase, offer or sale of the Notes under the laws and regulations in force in your jurisdiction to which you are subject or in which you make such purchase, offer or sale and neither the Issuer, the Guarantors nor the Initial Purchasers will have any responsibility therefor.

Neither the contents of our website nor of any website mentioned in this offering memorandum are part of, or are incorporated by reference into, this offering memorandum.

NOTICE TO PROSPECTIVE INVESTORS IN CHILE

THE OFFER OF THE NOTES IS SUBJECT TO GENERAL RULE NO. 336 OF THE CMF. THE NOTES BEING OFFERED WILL NOT BE REGISTERED UNDER THE CHILEAN SECURITIES MARKET ACT IN THE SECURITIES REGISTRY (*REGISTRO DE VALORES*) OR IN THE FOREIGN SECURITIES REGISTRY (*REGISTRO DE VALORES EXTRANJEROS*) BOTH KEPT BY THE CMF AND, THEREFORE, THE NOTES ARE NOT SUBJECT TO THE SUPERVISION OF THE CMF. AS UNREGISTERED SECURITIES, WE ARE NOT REQUIRED TO DISCLOSE PUBLIC INFORMATION ABOUT THE NOTES IN CHILE. ACCORDINGLY, THE NOTES CANNOT AND WILL NOT BE PUBLICLY OFFERED TO PERSONS IN CHILE UNLESS THEY ARE REGISTERED IN THE CORRESPONDING SECURITIES REGISTRY. THE NOTES MAY ONLY BE OFFERED IN CHILE IN CIRCUMSTANCES THAT DO NOT CONSTITUTE A PUBLIC OFFERING UNDER CHILEAN LAW OR IN COMPLIANCE WITH GENERAL RULE NO. 336 OF THE CMF. PURSUANT TO GENERAL RULE NO. 336, THE NOTES MAY BE PRIVATELY OFFERED IN CHILE TO CERTAIN "QUALIFIED INVESTORS" IDENTIFIED AS SUCH THEREIN (WHICH IN TURN ARE FURTHER DESCRIBED IN GENERAL RULE NO. 216, DATED JUNE 12, 2008, OF THE CMF), AND IN COMPLIANCE WITH APPLICABLE REGULATIONS TO SUCH INVESTORS.

NOTICE TO PROSPECTIVE INVESTORS IN THE EUROPEAN ECONOMIC AREA

THIS OFFERING MEMORANDUM IS NOT A PROSPECTUS FOR THE PURPOSES OF REGULATION 2017/1129/EU (AS AMENDED OR SUPERSEDED, THE "*PROSPECTUS REGULATION*"). THE NOTES ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND SHOULD NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY RETAIL INVESTOR IN THE EUROPEAN ECONOMIC AREA ("*EEA*"). FOR THESE PURPOSES, A RETAIL INVESTOR MEANS A PERSON WHO IS ONE (OR MORE) OF: (I) A RETAIL CLIENT AS DEFINED IN POINT (11) OF ARTICLE 4(1) OF DIRECTIVE 2014/65/EU, AS AMENDED ("*MIFID II*"); OR (II) A CUSTOMER WITHIN THE MEANING OF DIRECTIVE (EU) 2016/97, WHERE THAT CUSTOMER WOULD NOT QUALIFY AS A PROFESSIONAL CLIENT AS DEFINED IN POINT (10) OF ARTICLE 4(1) OF MIFID II. CONSEQUENTLY, NO KEY INFORMATION DOCUMENT REQUIRED BY REGULATION (EU) NO 1286/2014 (AS AMENDED, THE "*PRIIPS REGULATION*") FOR OFFERING OR SELLING THE NOTES OR OTHERWISE MAKING THEM AVAILABLE TO RETAIL INVESTORS IN THE EEA HAS BEEN PREPARED AND THEREFORE OFFERING OR SELLING THE NOTES OR OTHERWISE MAKING THEM AVAILABLE TO ANY RETAIL INVESTOR IN THE EEA MAY BE UNLAWFUL UNDER THE PRIIPS REGULATION. FOR THE PURPOSES OF THIS PROVISION, THE EXPRESSION AN "OFFER" INCLUDES THE COMMUNICATION IN ANY FORM AND BY ANY MEANS OF SUFFICIENT INFORMATION ON THE TERMS OF THE OFFER AND THE NOTES TO BE OFFERED SO AS TO ENABLE AN INVESTOR TO DECIDE TO PURCHASE OR SUBSCRIBE FOR THE NOTES. FURTHERMORE, THIS OFFERING MEMORANDUM HAS BEEN PREPARED ON THE BASIS THAT ANY OFFER OF NOTES IN THE EEA WILL ONLY BE MADE TO A PERSON OR ENTITY WHICH IS A QUALIFIED INVESTOR UNDER THE PROSPECTUS REGULATION. ACCORDINGLY, ANY PERSON MAKING OR INTENDING TO MAKE AN OFFER IN THE EEA OF THE NOTES MAY ONLY DO SO WITH RESPECT TO QUALIFIED INVESTORS. NONE OF THE GUARANTORS OR THE INITIAL PURCHASERS HAVE AUTHORIZED, NOR DOES EITHER OF THEM AUTHORIZE, THE MAKING OF ANY OFFER OF NOTES OTHER THAN TO QUALIFIED INVESTORS.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED KINGDOM

THIS OFFERING MEMORANDUM IS FOR DISTRIBUTION ONLY TO, AND IS DIRECTED SOLELY AT, PERSONS WHO (I) ARE OUTSIDE THE UNITED KINGDOM, (II) ARE INVESTMENT PROFESSIONALS, AS SUCH TERM IS DEFINED IN ARTICLE 19(5) OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 (FINANCIAL PROMOTION) ORDER 2005, AS AMENDED (THE "*FINANCIAL PROMOTION ORDER*"), (III) ARE PERSONS FALLING WITHIN ARTICLES 49(2)(A) TO (D) OF THE FINANCIAL PROMOTION ORDER OR (IV) ARE PERSONS TO WHOM AN INVITATION OR INDUCEMENT TO ENGAGE IN INVESTMENT BANKING ACTIVITY (WITHIN THE MEANING OF SECTION 21 OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 (THE "*FSMA*")) IN CONNECTION WITH THE ISSUE OR SALE OF ANY NOTES MAY OTHERWISE BE LAWFULLY COMMUNICATED OR CAUSED TO BE COMMUNICATED (ALL SUCH PERSONS TOGETHER BEING REFERRED TO AS "*RELEVANT PERSONS*"). THIS OFFERING MEMORANDUM IS DIRECTED ONLY AT RELEVANT PERSONS AND MUST NOT BE ACTED ON OR RELIED ON BY PERSONS WHO ARE NOT RELEVANT PERSONS. ANY INVESTMENT OR INVESTMENT ACTIVITY TO WHICH THIS OFFERING MEMORANDUM RELATES IS AVAILABLE ONLY TO RELEVANT PERSONS AND WILL BE ENGAGED IN ONLY WITH RELEVANT PERSONS. ANY PERSON WHO IS NOT A RELEVANT PERSON SHOULD NOT ACT OR RELY ON THIS OFFERING MEMORANDUM OR ANY OF ITS CONTENTS. EACH INITIAL PURCHASER HAS REPRESENTED AND AGREED THAT (A) IT HAS ONLY COMMUNICATED OR CAUSED TO BE COMMUNICATED AND WILL ONLY COMMUNICATE OR CAUSE TO BE COMMUNICATED AN INVITATION OR INDUCEMENT TO ENGAGE IN INVESTMENT ACTIVITY (WITHIN THE MEANING OF SECTION 21 OF THE FSMA) RECEIVED BY IT IN CONNECTION WITH THE ISSUE OR SALE OF THE NOTES IN CIRCUMSTANCES IN WHICH SECTION 21(1) OF THE FSMA DOES NOT APPLY TO THE ISSUER; AND (B) IT HAS COMPLIED AND WILL COMPLY WITH ALL APPLICABLE PROVISIONS OF THE FSMA WITH RESPECT TO ANYTHING DONE BY IT IN RELATION TO THE NOTES IN, FROM OR OTHERWISE INVOLVING THE UNITED KINGDOM.

AVAILABLE INFORMATION

Copies of the Indenture and the other Indenture Documents (as defined herein) will be available, free of charge, upon written request by any investor to the Indenture Trustee.

The information contained in this offering memorandum regarding Chile and Chilean power industry has been derived exclusively from publicly available documents. None of the Issuer, the Guarantors or the Initial Purchasers has participated in the preparation of publicly available documents with respect to Chile or the Chilean power industry, in connection with the offering of the Notes or otherwise. None of the Issuer, the Guarantors or the Initial Purchasers makes any representation that this information, whether or not taken together with publicly available documents or any other publicly available information regarding Chile or the Chilean power industry, is accurate or complete.

Each person purchasing Notes will be deemed at the time of the purchase, by its acceptance thereof, to acknowledge and agree that (1) it has relied on its own investigation and publicly available sources to make its investment decision and determination related to information about the Issuer and the Notes; (2) it has not relied on the Initial Purchasers or any of their respective affiliates in connection with its investigation of the information contained in this offering memorandum or its investment decision, and (3) no person has been authorized to give any information or to make any representation concerning the Notes other than those contained in this offering memorandum and, if given or made, such other information or representation should not be relied upon as having been authorized by the Issuer or the Initial Purchasers. See "*Transfer Restrictions*" for certain additional representations, acknowledgments and agreements investors will be deemed to have made. Prospective investors are strongly advised to make their own independent evaluations with respect to the Issuer's business, results of operations and financial condition prior to making an investment decision with respect to the Notes. See "*Risk Factors—Risks Related to Our Business*" and "*Risk Factors—Risks Relating to the Notes*."

Any publicly available information regarding Chile or the Chilean power industry that is not included in this offering memorandum is not deemed part of, or incorporated by reference into, this offering memorandum, and the contents of any website mentioned in this offering memorandum are not part of, nor are they incorporated by reference into, this offering memorandum. Information included in this offering memorandum and identified as being derived from information published by Chile or one of its agencies or instrumentalities is included herein on the authority of such publication as a public official document of Chile.

In addition, information regarding Chile and the Chilean power industry may be obtained from other sources including, but not limited to, press releases, newspaper articles and other publicly disseminated documents. There can be no assurance that any publicly available information with respect to Chile or the Chilean power industry will be up to date or otherwise accurate in all respects material to an investment of the Notes.

THE ISSUER IS NOT SUBJECT TO THE INFORMATION REQUIREMENTS OF THE U.S. SECURITIES EXCHANGE ACT OF 1934, AS AMENDED (THE "*EXCHANGE ACT*"), AND THE NOTES HAVE NOT BEEN, AND WILL NOT BE, REGISTERED UNDER THE SECURITIES ACT. IN ORDER TO PRESERVE THE EXEMPTIONS FROM REGISTRATION UNDER THE SECURITIES ACT AVAILABLE TO INVESTORS FOR RESALE AND TRANSFERS OF THE NOTES UNDER RULE 144A, THE ISSUER HAS AGREED THAT WHILE ANY NOTES REMAIN OUTSTANDING, THE ISSUER WILL MAKE AVAILABLE, UPON REQUEST, TO ANY BENEFICIAL OWNER AND ANY PROSPECTIVE PURCHASER OF NOTES, THE INFORMATION REQUIRED PURSUANT TO RULE 144A(D)(4) UNDER THE SECURITIES ACT, UNLESS AT SUCH TIME THE ISSUER IS SUBJECT TO THE REPORTING REQUIREMENT OF SECTION 13 OR 15(D) OF THE EXCHANGE ACT OR EXEMPT FROM SUCH REQUIREMENTS PURSUANT TO RULE 12G3-2(B) UNDER THE EXCHANGE ACT. REQUESTS FOR INFORMATION SHOULD BE DIRECTED TO THE ISSUER AT ITS CURRENT REGISTERED OFFICE LOCATED AT THE OFFICES OF CERRO EL PLOMO 5.680, OFICINA 1202, LAS CONDES, SANTIAGO, CHILE.

ENFORCEMENT OF CIVIL LIABILITIES

The Issuer is a limited liability company (*sociedad de responsabilidad limitada)* formed under the laws of Chile. Each of the Guarantors is a corporation (*sociedad anónima*) incorporated under the laws of Chile. The Issuer, the Guarantors and each of their respective directors and officers reside outside the United States (principally in Chile). All or a substantial portion of the assets of these persons and entities are or may be located outside the United States. As a result, it may not be practicable for the Indenture Trustee or investors in the Notes to effect service of process within the United States upon such persons or entities or to enforce against them in U.S. courts judgments predicated upon the civil liability provisions of the laws of jurisdictions other than the jurisdictions in which such persons or entities are located, including any judgments predicated upon the civil liability provisions of the federal securities laws of the United States or any applicable securities laws of any State of the United States.

The Issuer and the Guarantors have no assets that have not been pledged for the benefit of investors. All of their administrators, directors and executive officers reside outside of the United States and investors will have no recourse against such entities or persons. Further, the assets of these persons are located outside the United States. As a result, it may not be possible for investors to effect service of process within the United States, or bring actions or enforce foreign judgments against us or such persons in U.S. courts.

The Issuer has been advised by its Chilean counsel, Barros, Silva, Varela & Vigil Abogados Ltda., that no treaty exists between the United States and Chile for the reciprocal enforcement of foreign judgments. Chilean courts, however, have enforced final judgments rendered in the U.S., without reviewing the merits of the subject matter of the case, by virtue of the legal principles of reciprocity and comity, subject to the review in Chile of the U.S. judgment in order to ascertain whether certain basic principles of due process and public policy have been respected. If a U.S. court grants a final judgment for the payment of money, enforceability of this judgment in Chile will be subject to the obtainment of the relevant *exequatur* (*i.e.*, recognition and enforcement of the foreign judgment) according to Chilean civil procedure law in force at that time and, consequently, subject to the satisfaction of certain factors. Currently, the most important of these factors are (absent of a treaty between the United States and Chile for the reciprocal enforcement of foreign judgments):

(1) the judgment will be enforced if there is reciprocity as to the enforcement of judgments (*i.e.*, the relevant U.S. court would enforce a judgment of a Chilean court under comparable circumstances); if it can be proved that there is no reciprocity, the foreign judgment will not be enforced in Chile; and

(2) if reciprocity cannot be proved to exist, the foreign judgment nonetheless will be enforced if: (i) it does not contain anything contrary to Chilean law, notwithstanding the differences in procedural rules, (ii) it is not contrary to Chilean jurisdiction and public policy, (iii) it has been duly served, although the defendant may prove that for other reasons it has been prevented from using its means of defense (this specific standard was set forth in a ruling from the Chilean Supreme Court and further guidance was not provided in such ruling) and (iv) it is final under the laws of the country where the judgment or arbitral award, as the case may be, was rendered.

We have been advised by our Chilean counsel that there is doubt as to the enforceability, in original actions in Chilean courts, of liabilities predicated solely upon the federal securities laws of the United States and as to the enforceability in Chilean courts of judgments of U.S. courts obtained in actions predicated upon the civil liability provisions of the U.S. federal securities laws. See "*Risk Factors—Risks Relating to the Notes.*" Holders of Notes may find it difficult or impossible to enforce civil liabilities against us, our directors, officers and controlling persons.

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

As used in this offering memorandum, references to (a) the "*Issuer*" or "*ILAP*" are to Inversiones Latin América Power Ltda., and (b) the "*Company*" are to the Issuer and the Guarantors on a consolidated basis.

Unless otherwise specified, references herein to "*U.S. Dollars*," "*Dollars*," "*US$*" or "*$*" are to United States Dollars, the legal and official currency of the United States, and "*CLP*" or "*Pesos*" refer to Chilean Pesos, the legal and official currency of Chile. See "*Exchange Rates*" and "*Exchange Controls*" for information regarding exchange rates for Pesos since 2017.

Gross Domestic Product, or "*GDP*," means the total value of final products and services produced in Chile during the relevant period, using nominal prices.

Our functional currency is U.S. Dollars. Consequently, the financial information presented herein is in U.S. Dollars, except as otherwise indicated. Transactions in a foreign currency (currency different from the functional currency) are converted into our functional currency at the dates of the transactions (the main non-Dollar currency used by us is Pesos). This offering memorandum contains translations of certain currency amounts into U.S. Dollars at specified rates solely for the convenience of readers. These translations should not be construed as representations that the currency amounts actually represent the respective U.S. Dollar amounts, were converted to U.S. Dollars at the rate indicated or could be converted into U.S. Dollars at the rate indicated. Unless otherwise indicated, translations of currency amounts into U.S. Dollars in this offering memorandum have been made at the period-end rates of each corresponding period. See "*Exchange Rates*" and "*Exchange Controls.*"

Financial Statements

This offering memorandum includes the audited consolidated financial statements of ILAP and the Guarantors on a consolidated basis as of December 31, 2020 and 2019 and for each of the three years in the period ended December 31, 2020, together with notes thereto (the "*Audited Consolidated Financial Statements*"), which are presented in U.S. Dollars, prepared in accordance with International Financial Reporting Standards ("*IFRS*") issued by the International Accounting Standards Board ("*IASB*"). The offering memorandum also includes unaudited interim consolidated financial statements of ILAP and the Guarantors on a consolidated basis as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020 (the "*Unaudited Consolidated Financial Statements*"), which are presented in U.S. Dollars, prepared in accordance with IFRS. The Audited Consolidated Financial Statements and the Unaudited Consolidated Financial Statements are referred to as the "*Consolidated Financial Statements*" in this offering memorandum.

The Audited Consolidated Financial Statements have been audited by our current independent auditors, EY Audit SpA ("*EY Chile*"). The report of EY Chile on such financial statements appear elsewhere in this offering memorandum.

Alternative Performance Measures

In this offering memorandum, we have included references to certain non-IFRS measures and ratios, including Adjusted EBITDA. These measures are included because they are considered to provide relevant and useful additional information to investors. You should exercise caution in comparing the non-IFRS measures as reported by us to non-IFRS measures of other companies. Non-IFRS measures have limitations as an analytical tool, and you should not consider them in isolation or as a substitute for analysis of our operating results as reported under IFRS.

We define "*Adjusted EBITDA*" as gain (loss) after adding back (to the extent the number is negative) or subtracting (to the extent the number is positive), as the case may be, (1) income tax benefit (expense), (2) foreign exchange differences, (3) finance expense, (4) finance income, (5) interests withholding tax, (6) impairment charges, and (7) depreciation and amortization.

"*Total debt*" reflects the total of our financial obligations and is calculated as the sum of current and non-current portions of our indebtedness under NPA (excluding related deferred financing expenses) plus lease liabilities. We believe that total debt provides a useful indication of our financial position, including our ability to repay outstanding debt when comparing to our available cash and other highly liquid assets.

Market Data and Other Information

We obtained the market and industry data and other statistical information used throughout this offering memorandum from our own research, surveys or studies conducted by third parties, independent industry or general publications and other published independent sources, including the annual statistical compendium published by the

National Electrical Coordinator (*Coordinador Independiente del Sistema Eléctrico Nacional)*, an autonomous entity in charge of coordinating the efficient and safe operation and dispatch of generation units to satisfy demand, and public documents published by the CNE, the National Energy Commission (*Comisión Nacional de Energía*), a governmental entity operating under the Chilean regulatory framework, available at www.cne.cl, as well as the Ministry of Energy and the Central Bank. To the extent any such data or other information relates to the Chilean government or Chilean macroeconomic data or other third-party publications or sources, such data or information has not been independently verified by us or the Initial Purchasers. While we believe that each of these sources, including the estimates of the National Electrical Coordinator and CNE, is reliable, they are themselves subject to assumptions and involve judgments and estimates, and neither we nor the Initial Purchasers have independently verified such data, and neither we nor the Initial Purchasers make any representations as to the accuracy of such information. Similarly, we believe our internal research is reliable, but it has not been verified by any independent sources. Where information in this offering memorandum has been sourced from third parties this information has been accurately reproduced and as far as we are aware and able to ascertain from the information published by such third parties no facts have been omitted which would render the reproduced information inaccurate or misleading. The source of third party information is identified where used.

Independent Market Consultant Report

Certain of the information in this offering memorandum regarding the Chilean electricity industry was derived from the Independent Market Consultant Report, dated May 17, 2021 (the "*Independent Market Consultant Report*"), prepared by Valgesta Energía (the "*Independent Market Consultant*"), and included as an appendix to this offering memorandum.

Any projections and estimates contained in the Independent Market Consultant Report are for reference purposes only, and, accordingly, prospective investors are cautioned not to place undue reliance on these reports or, in each case, the projections or estimates contained therein. Such estimates and projections may be based on certain assumptions that may prove to be inaccurate. Under no circumstances should the inclusion of these projections or estimates in this offering memorandum be regarded as a representation or warranty by the Company, the Initial Purchasers or any other person with respect to the accuracy of the projections or estimates, or the accuracy of their underlying assumptions. Investors may not rely upon the summaries and excerpts in this offering memorandum and should review the Independent Market Consultant Report in full. Without limiting the generality of the foregoing, the Independent Market Consultant Report is expressly subject to the qualifications, assumptions made, procedures followed, matters considered and any limitations on the scope of work contained therein. The Independent Market Consultant Report speaks only as of its date, and the occurrence of unanticipated events or any other events since that time that could render the projections inaccurate are not reflected in that report.

The Independent Market Consultant Report has been prepared using, as applicable, judgments, analyses, projections and estimates, including with respect to supply and demand of electricity, market conditions, weather, inflation and other information and projections, available to the Independent Market Consultant at the time of preparation of the Independent Market Consultant Report, including, without limitation, certain related assumptions, analyses, projections and estimates. In our opinion, however, we believe that the Independent Market Consultant Report was prepared on a reasonable basis, reflecting the best estimates and judgments available. The information that has not been provided by us and assumptions that form the basis for the Independent Market Consultant Report have not been subject to any independent examination or verification by the Initial Purchasers or the Company, or by their independent auditors or other advisors. In particular, it should be noted that the Independent Market Consultant Report may reflect assumptions, qualifications, procedures and methodologies that differ in various degrees from the assumptions, qualifications, procedures and methodologies used by the Company, the CNE or the Ministry of Energy for the preparation of their own projections and market analyses. You should understand that the information contained in the Independent Market Consultant Report, including projections, estimates, judgments and forward-looking statements, is subject to material risk and uncertainty. In view of these uncertainties, investors should not rely on these projections, estimates, judgments and forward-looking statements to make their investment decisions and are encouraged to carefully analyze the information included elsewhere in this Offering Memorandum.

The information included in the Independent Market Consultant Report should not be taken as an indication of (1) the outlook for our operations, (2) a guarantee of our future performance, (3) a guarantee of the performance of the Tariff Stabilization Framework, the recognition of PEC Receivables or the generation of Surpluses, or (4) a guarantee of market conditions. The projections, estimates, judgments and forward-looking statements included in the Independent Market Consultant Report may not be realized considering that they are subject to and based on assumptions, including, among others, certain of those described in "*Forward-Looking Statements*."

Independent Engineer Report

Information in this offering memorandum regarding the development, design, construction, operations and projected operating results of the Projects was derived from the Independent Engineer Report, dated June 1, 2021 (the "*Independent Engineer Report*"), prepared by Arup Latin America, S.A. (the "*Independent Engineer*"), and included as an appendix to this offering memorandum.

The Independent Engineer Report has been prepared based upon the experience of such firm as an engineering consulting firm that provides consulting services to the power generation industry. The Independent Engineer Report is included in this offering memorandum in reliance upon the authority of such firm as a professional advisor in these matters. The Independent Engineer is an independent engineer with respect to the Company and its affiliates and does not own any interest in the assets covered by the Independent Engineer Report.

Any projections and estimates contained in the Independent Engineer Report are for reference purposes only, and, accordingly, prospective investors are cautioned not to place undue reliance on these reports or, in each case, the projections or estimates contained therein. Such estimates and projections may be based on certain assumptions that may prove to be inaccurate. Under no circumstances should the inclusion of these projections or estimates in this offering memorandum be regarded as a representation or warranty by the Company, the Initial Purchasers or any other person with respect to the accuracy of the projections or estimates, or the accuracy of their underlying assumptions. Investors may not rely upon the summaries and excerpts in this offering memorandum and should review the Independent Engineer Report in full. Without limiting the generality of the foregoing, the Independent Engineer Report is expressly subject to the qualifications, assumptions made, procedures followed, matters considered and any limitations on the scope of work contained therein. The Independent Engineer Report speaks only as of its date, and the occurrence of unanticipated events or any other events since that time that could render the projections inaccurate are not reflected in that report.

This offering memorandum contains excerpts and summaries from selected provisions of the Independent Engineer Report and is not a full statement of the terms of those documents. Accordingly, the excerpts or summaries in this offering memorandum are qualified in their entirety by reference to and are subject to the full text of such report. Investors may not rely upon the summaries and excerpts in this offering memorandum and should review the full report, which is subject to the limitations or disclaimers in that report or otherwise set forth in the disclaimers thereto. Without limiting the generality of the foregoing, the Independent Engineer Report is expressly subject to the qualifications, assumptions made, procedures followed, matters considered and any limitations on the scope of work contained therein. Investors should note that these summaries, and the attached report, are provided only as of the date set forth therein and do not contemplate any event, circumstances or changes with respect to the Projects or otherwise after such date.

The prospective projected operating results included in the Independent Engineer Report were not prepared by the Independent Engineer with a view toward compliance with any published guidelines of the SEC, nor the guidelines established by the American Institute of Certified Public Accountants or by any accounting regulators in Chile.

Independent Insurance Report

Information in this offering memorandum regarding the insurance policies for the Projects was derived from a report dated June 1, 2021 (the "*Insurance Report*"), prepared by Aon M&A and Transaction Solutions (the "*Independent Insurance Advisor*"), which is not included in or attached to this offering memorandum.

This offering memorandum contains summaries from selected provisions of the Insurance Report but does not include a full statement of the terms of the Insurance Report. Accordingly, the summaries in this offering memorandum are qualified in their entirety by reference to and are subject to the full text of such report.

Second-Party Opinion

Standard & Poor's Financial Services LLC has provided a Green Framework Alignment Opinion dated June 1, 2021 (the "*Second-Party Opinion*") about the transaction's alignment with the International Capital Market Association's (ICMA) Green Bond Principles (2018) (the "*GBP*") and Green Loan Principles 2021 ("*GLP*").

The Initial Purchasers and the Issuer make no assurances as to the suitability of the Second-Party Opinion or the Notes to fulfill such environmental and sustainability criteria. The Second-Party Opinion is not incorporated into and does not form part of this offering memorandum.

Description of Material Agreements and Transaction Documents

This offering memorandum contains summary descriptions of material provisions of various material agreements (e.g., PPAs) and Transaction Documents. Such descriptions do not purport to be complete or exhaustive. In addition, as with any contract or legal instrument, the terms thereof may be subject to interpretation. See "*Our Business—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*" and "*Description of the Notes*."

We take responsibility for the correct extraction and reproduction of the information contained in this offering memorandum.

Rounding

Some figures included in this offering memorandum may not represent exact amounts because they were rounded up or down for ease of presentation. Accordingly, the total results shown in tables included elsewhere in this offering memorandum may not correspond to the exact arithmetic sum of the figures that precede them.

Defined Terms

Capitalized terms used but not defined in this offering memorandum have the meanings specified in Annex A hereto.

Certain Assumptions

This offering memorandum contains tables and other information on projected cash flows, payment amounts on scheduled payment dates and target debt balance amounts which have been calculated on the basis of the following assumptions:

- an offering size of US$403.9 million of Notes;
- a 5.00% per annum yield rate on the Notes; and
- the launch of the offering, based on which the information in all tables and the other information referred to above in this section have been calculated, will occur on June 2, 2021.

The final offering price and yield to maturity of the Notes will be determined at the time of pricing and may be different to the assumptions and amounts set out above and in this offering memorandum. This information included in this offering memorandum related to the pricing of the Notes is for illustration purposes only and is subject to change.

FORWARD-LOOKING STATEMENTS

This offering memorandum includes "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act, including, but not limited to all statements regarding our future financial position, operations, strategy, plans, objectives, goals, targets, beliefs, expectations and projections about present and future events and financial trends affecting our business and financing plans. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts and includes all statements that address activities, events or developments that are expected, believed or anticipated to occur or that may occur in the future. In particular, statements, express or implied, concerning future operating results or financial position, prospects, plans and objectives of management or the ability to generate revenues, income or cash flow or to make payments on the Notes and other indebtedness are forward-looking statements. These statements may be identified by the use of words such as "anticipate," "believe," "estimate," "expect," "intend," "may," "plan," "predict," "target," "forecast," "strategy" or the negative of those terms or other variations of them or comparable terminology.

The expectations reflected in such forward-looking statements in this offering memorandum are based on information currently available to us and our advisors. However, no person can give any assurance that these expectations will prove to have been correct. All expectations and projections are subject to significant known and unknown risks, uncertainties and other factors, some of which are beyond the control of the parties stated herein and which may cause the actual results, performance or achievements, or industry results, to be materially different from any expected or projected results, performance or achievements expressed or implied by such forward-looking statements. Important factors that could cause actual results to differ materially from such expectations are disclosed in this offering memorandum, including, without limitation, those listed under "*Risk Factors*." All forward-looking statements, including, but not limited, to those attributable to us are expressly qualified in their entirety by the cautionary statements contained in this paragraph. We do not undertake any obligation, other than as required by applicable law, to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Such forward-looking statements are subject to risks and uncertainties, and actual results may differ materially from those expressed or implied in the forward-looking statements as a result of various factors, including, but not limited to:

- dependence on counterparties to generate substantially all of our revenue;
- dependence on wind conditions and other factors beyond our control to generate electricity;
- the variability in Chilean electricity supply and demand dynamics, which may result in differences between expected and realized prices and surpluses;
- the maintenance of relationships with customers;
- the enactment and limited precedent for application of the Tariff Stabilization Law;
- the interpretation of the legal framework governing the Tariff Stabilization Framework;
- our ability to enter into new PPAs at similarly favorable terms as our current PPAs;
- customer losses or losses of other sources of revenues, including upon the termination or nonrenewal of our material project agreements;
- partial dependence on revenue derived from spot market;
- changes in laws or governmental regulations that adversely affect us or the PEC Receivables;
- the political and economic condition of the Chilean and world economies;
- the novel coronavirus ("*COVID-19*") pandemic, together with governmental measures implemented to prevent its spread, and their impact on the economic and financial situation;
- potential or ongoing investigation, litigation, arbitration or administrative proceedings;
- our ability to fund and implement our ongoing maintenance capital expenditure programs;

- dependence on interconnection and transmission infrastructure;
- the loss of qualified employees or our ability to retain qualified employees;
- the effects from competition and regulation;
- changes in our regulatory environment, including the costs of complying with environmental and renewable energy regulations;
- the relative value of the Chilean peso as compared to the U.S. dollar;
- natural disasters;
- cyber-attacks and system integrity;
- increases in interest rates;
- adverse events related to any DisCo's business, results of operations, financial condition or prospects, which negatively impact such DisCo's ability or willingness to perform their respective obligations under the Tariff Stabilization Framework or otherwise in connection with the PEC Receivables;
- limited remedies for the failure by Chilean government entities to perform certain actions required under the Tariff Stabilization Framework;
- restrictions, regulations and covenants which may adversely affect the value of the Notes; and
- rights of security interest and noteholders which may adversely affect the value of the Notes.

Some of these factors are discussed under "*Risk Factors*," but there may be other risks and uncertainties not discussed under "*Risk Factors*" or elsewhere in this listing memorandum that may cause actual results to differ materially from those in forward-looking statements.

In any event, these statements speak only as of the date of this listing memorandum, and we do not undertake any obligation to update or revise any of them as a result of new information, future events or otherwise.

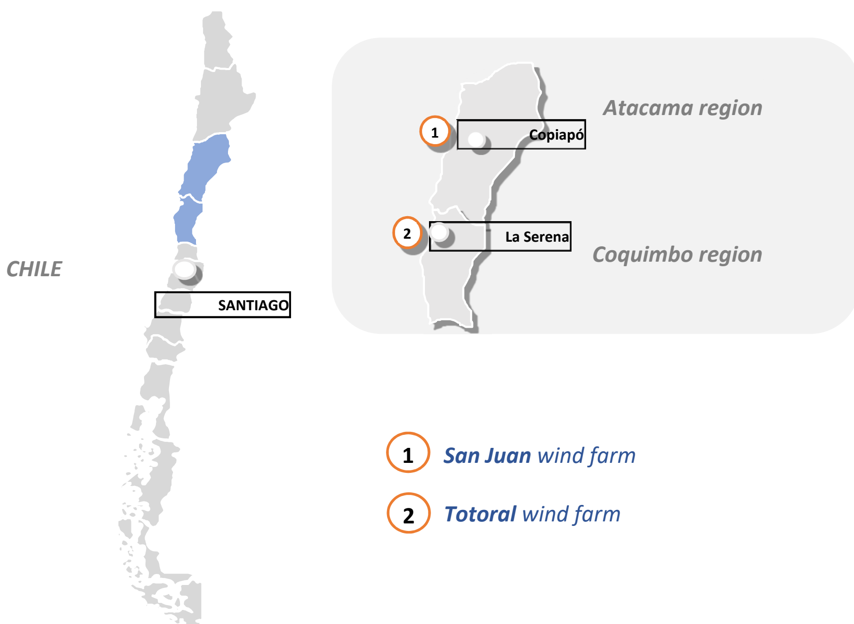
SUMMARY

The following summarizes certain relevant information included elsewhere in this offering memorandum and does not contain all of the information prospective investors should consider in making an investment decision. Prospective investors should read this summary together with, and this summary is qualified in its entirety by, the more detailed information appearing elsewhere in this offering memorandum. Investing in the Notes involves a significant degree of risk. See "Risk Factors."

Overview

We are a clean energy company that owns and operates wind generation plants with an aggregate installed capacity of 239.2MW and is engaged in the generation of electricity business in northern Chile. We own and operate two wind farm projects: (i) the San Juan Project, a 193.2 MW facility located in Vallenar in the region of Atacama, currently the second largest wind farm project in the country, and (ii) the Totoral Project, a 46.0 MW facility located in Canela, in the region of Coquimbo. The San Juan Project has been fully operational since March 2017 and the Totoral Project has been fully operational since January 2010. Both wind projects are located in areas characterized for their strong and highly predictable wind resource, which is considered favorable for the development of wind farms utilizing Vestas.

The map below provides an overview of the location and general specifications of the San Juan Project and the Totoral Project:



Source: ILAP.

We sell the electric power generated by our wind farm projects into the SEN (*Sistema Eléctrico Nacional*), the national electric system of transmission that provides electricity to almost the entire country. The SEN was created in 2017 after the interconnection of the two largest existing systems in the country, the SIC (*Sistema Interconectado Central*) and the SING (*Sistema Interconectado del Norte Grande*). The operation of the SEN, the SIC and the SING is coordinated by the National Electrical Coordinator.

Our main customers are highly-rated regulated DisCos (utility power distribution companies) and other large, experienced companies in varied industrial sectors (through long-term power purchase agreements (PPAs)), which provide a very stable source of recurring cash flow. As of March 31, 2021, 89.7% of our capacity at P50 is fully contracted under PPAs with tenors ranging from 4 to 12 years, and a weighted average life span of existing PPAs of

10.6 years, with DisCo PPAs expiring between 2031 and 2033. For the three-month period ending March 31, 2021, 86.9% of our revenue derived from sales of energy from PPAs, and over the fiscal years ended December 31, 2020, 2019 and 2018, 94.1%, 92.8% and 83.8% of our revenue derived from sales of energy from PPAs, respectively. Our most important individual PPA counterparty is Metro (Empresa de Transporte de Pasajeros Metro S.A., the operator of Santiago's subway system), a government-controlled entity rated A and A- by S&P and Fitch Ratings, respectively, representing 12.0% of our revenue for the three-month period ending March 31, 2021, and 13.1%, 27.9% and 24.8% for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively. The PPA with Metro expires in 2032. See "*Our Business—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*." We sell any excess energy to other power generation companies in the spot market. Spot market revenue represented in aggregate 13.1% of our revenue for the three-month period ending March 31, 2021, and 5.9%, 7.2% and 16.2%, for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively.

For the three-month period ending March 31, 2021, our total net generation was 129.4 GWh, and for each of the years ended December 31, 2020, 2019 and 2018, our aggregate net generation was 601.1 GWh, 661.3 GWh and 634.6 GWh, respectively, with an aggregate availability factor of 94.5%%, 95.9%, 96.9% and 97.3%, and an aggregate capacity factor of 25.0%, 28.7%, 31.8% and 31.4%, respectively. According to the Independent Engineer, the average annual sold generation by the San Juan Project since start of operations is 551.7 GWh/yr and the average total windfarm availability is 96.3%, and the average annual sold generation by the Totoral Project since start of operations is 80.1 GWh/yr and the average total windfarm availability is 96.8%.

For the three-month period ending March 31, 2021, our revenue totaled US$15,617 thousand, and with respect to each of the fiscal years ended December 31, 2020, 2019 and 2018, our revenue totaled US$72,887 thousand, US$62,516 thousand and US$52,097 thousand, respectively. Our Adjusted EBITDA increased from US$28,509 thousand to US$33,741 thousand from the year ended December 31, 2018 to the year ended December 31, 2019, and further, increased to US$36,887 thousand from the year ended December 31, 2020. Our Adjusted EBITDA decreased from US$9,607 thousand to US$5,571 thousand from the three-month period ending March 31, 2020 to the three-month period ending March 31, 2021, due to an increase in marginal costs as further explained under "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Our Results of Operations—Revenues—Factors Affecting the Level of Revenues—Volatility Conditions During the three months ended March 31, 2021.*"

The Projects

San Juan Project

The San Juan Project is a 193.2 MW wind farm facility located in Vallenar, Region of Atacama, Chile (approximately 650 Km north of Santiago). The asset is comprised of 56 Vestas V117-3.45 MW wind turbines, making it the second largest single wind farm in Chile. The San Juan Project began partial operations in July 2016 and achieved full commercial operation in March 2017. The San Juan Project was built by Elecnor, a leading global EPC and renewable energy investor, and employs wind turbines supplied by Vestas, the world's most experienced wind turbine manufacturer. Vestas is responsible for the operation and maintenance of the turbines under the Service and Availability Agreement between San Juan and Vestas dated March 25, 2015, as amended on January 29, 2021, through 2037, that guarantees generation availability of 97% per turbine, increasing to 98% starting in 2022. See "*Our Business—Operations and Maintenance—O&M Agreements*." According to the Independent Engineer, Vestas has an excellent history of supporting wind turbine manufacture, installation and operations across the world.

According to Vestas, the expected useful life of the wind turbines with respect to the San Juan Project is up to 30 years, provided a proper and adequate maintenance plan is in place, and the remaining useful life is expected to be 25 years with respect to the San Juan Project. The San Juan Project was originally developed by our parent LAP Chile, and its current legal owner is San Juan, which we formed on 2013.

The area surrounding the San Juan Project is characterized by its strong and highly predictable wind resources (averaging 7.5 m/s at hub height). According to the Independent Engineer, this climate is considered favorable for the development of wind farms utilizing Vestas V117-3.45 MW turbines. Since commencing operations, the San Juan Project has exhibited average annual generation of 551.7 GWh/yr. and an average availability of 96.3%. The San Juan Project sells power into the SEN and is connected to the grid at the Punta Colorada substation owned by Transelec, via an 85km transmission line at 220 kV. We have an interconnection agreement with Transelec that will remain in force as long as the connection line is installed and in operation. See "*Our Business— Interconnection and Interconnection Maintenance Agreement*." For further details on the key equipment and technology of the San Juan Project, see "*Our Business—Equipment and Technology*" below.

San Juan, as the legal owner of the San Juan Project, is party to 67 long-term PPAs with a diversified group of DisCos to supply Regulated Customers. These offtakers are highly regulated entities that provide electricity service to both non-regulated and regulated end customers in Chile. These PPAs consist of U.S. Dollar denominated 15-year "take-and-pay" agreements, and were entered into after the tender process known as "2013-3 Second Call Auction/Tender Process" administered by the CNE, the Chilean National Energy Commission (*Comisión Nacional de Energía*), held in December 2014. In 2016, San Juan also entered into an additional offtake agreement with Metro, an Unregulated Customer rated A by S&P and A- (Stable) by Fitch Ratings. Under that agreement, San Juan has contractually committed to supply up to 60% of Metro's hourly consumption that is not supplied by solar priority suppliers. In addition, San Juan has a PPA entered into in 2017 with Enel Distribución, a power distribution company controlled by Enel Chile (rated BBB+ by S&P, Baa2 by Moody's and A- (Fitch), for which we provide an annual average contracted energy of 180 GWh (with a "take-or-pay" of 70%, 126 GWh) until 2023. The PPA allowed Enel Distribución to secure electricity volumes to supply Enel Distribución's unregulated customers. However, effective January 1, 2021, Enel Distribución assigned the PPA to Enel Generación as a result of regulatory changes introduced to the Electricity Law that prevented distribution companies to dedicate to business other that the supply of electricity to regulated customers. Enel Generación is the largest power company in Chile, also controlled by Enel Chile (rated BBB+ by S&P, Baa1 by Moody's and A- by Fitch). See "*Our Business—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*."

The San Juan Project provides annual average contracted energy of 381 GWh with respect to the PPAs with DisCos, 75 GWh with respect to the PPA with Metro and 180 GWh with respect to the PPA with Enel Generación, at average PPA prices of US$109.97/MWh, US$102.18/MWh, and US$48.65/MWh respectively.

Totoral Project

The Totoral Project is a 46.0 MW wind farm facility located in Canela, Region of Coquimbo, Chile (approximately 300 km north of Santiago). The asset is comprised of 23 Vestas V90-2.0 MW wind turbines and began commercial operations in January 2010. The Totoral Project was built by SKANSKA, a world-leading project development and construction group, and with wind turbines supplied by Vestas.

According to Vestas—our turbine provider and current O&M (operations and maintenance) contractor—the expected useful life of the wind turbines with respect to the Totoral Project is up to 30 years, provided a proper and adequate maintenance plan is in place, and the remaining useful life is expected to be 20 years with respect to the Totoral Project. Vestas is responsible for the operation and maintenance of the turbines under the Service and Availability Agreement between Norvind and Vestas dated April 1, 2013, as amended on December 14, 2016 through 2029, that guarantees generation availability of 97% per turbine. See "*Our Business—Operations and Maintenance—O&M Agreements*." The Totoral Project's legal owner is Norvind and was originally developed by SN Power AS. We acquired Norvind from SN Power AS in 2013.

The area surrounding the Totoral Project is characterized for its steady wind resource. Since commencing operations, the Totoral Project has exhibited average annual generation of 83.4 GWh/yr. and an average availability of 97%. The Totoral Project also sells power into the SEN, and is connected to the grid at the Las Palmas substation owned by Transelec, via a 7 km transmission line at 220 kV. We have an interconnection agreement with Transelec that will remain in force as long as the connection line is installed and in operation. See "*Our Business—Interconnection and Interconnection Maintenance Agreement*." For further details on the key equipment and technology of the Totoral Project, see "*Our Business—Equipment and Technology*" below.

Norvind, as the legal owner of the Totoral Project, was also awarded long-term U.S. Dollar denominated PPAs as a result of "2013-3 Second Call Auction/Tender Process" in December 2014. Norvind has 23 PPAs with 23 DisCos to supply Regulated Customers consisting of DisCos that began in January 2019 and will continue through December 2033. Under these agreements, the Totoral Project will sell an annual average of 45.5 GWh of contracted energy at an average PPA price of $113.2/MWh. Additionally, Norvind has 15 bilateral PPAs with Unregulated

Customers and a power generation company to supply an average of 8.9 GWh expiring between 2022 and 2025. The Unregulated Customers range from large retail stores to universities and agro-industrial facilities. In aggregate, for the three-month period ending March 31, 2021, the Totoral Project's PPAs comprised 11.8% of our consolidated revenue, and for each of the years ended December 31, 2020, 2019 and 2018, these PPAs comprised 13.7%, 10.7% and 5.7% of our consolidated revenue, respectively.

PPAs and Main Counterparties

We earn contracted revenues from our PPAs with Contracted Customers (customers subject to a PPA), consisting of DisCos, Unregulated Customers and certain power companies (i.e. Enel Generación, Pacific Hydro Chacayes and Cinergia). We sell any excess power in the spot market. As of the date of this offering memorandum, we are party to 108 PPAs with 41 separate counterparties: San Juan is party to 67 PPAs with DisCos and three with Unregulated Customers, and Norvind is party to 23 PPAs with DisCos and 15 with Unregulated Customers. Our PPAs, in aggregate, have a weighted average term of 10.6 years.

For the fiscal year 2021, we estimate that 623.63 GW/h of our total generation capacity (at P50) will be contracted, representing 98.44% of the estimated total generation for the period. During the three months ended March 31, 2021 we sold 128.0 GW/h to Contracted Customers, and during the years ended December 31, 2020, 2019 and 2018, we sold 609.9 GW/h, 532.9 GW/h and 360.1 GW/h to Contracted Customers, respectively. During the three months ended March 31, 2021, 13.1% of our total revenues corresponded to energy sold in the spot market, and during the years ended December 31, 2020, 2019 and 2018, the energy sold to the spot market represented 5.9%, 7.2% and 16.2% of our total revenues, respectively.

PPAs with DisCos are long-term contracts, generally with a 15-year term, and serve Regulated Customers who have a peak load below 5 MW (customers with a peak load between 0.5 MW and 5 MW who are located in the area of a concession of a DisCo, may choose to be Unregulated Customers). The contractual terms and conditions, with the exception of the tariff, contracted demand and contract period clauses, are standard in nature and non-negotiable. These PPAs generally consist of U.S. Dollar denominated 15-year "take-and-pay" agreements, and were entered into after the tender process known as "2013-3 Second Call Auction/Tender Process" administered by the CNE, held in December 2014. During that process, San Juan was awarded Blocks 2-A, 2-C and 3, and Norvind was awarded Block 4, with end dates between December 31, 2031 and December 31, 2033. As a result, our Projects have received favorable long-term contracts with a diversified group of DisCos.

The table below summarizes the tenors, prices and contracted demand for each of the blocks awarded:

Company	Block	Client	Beg. Date	End Date	Term	Price (USD/MWh)	Energy GWh/y
San Juan	**2-A**	23 DisCos(1)	January 1, 2017	December 31, 2031	15 years	100.646(2)	68.2
San Juan	**2-C**	23 DisCos(1)	January 1, 2017	December 31, 2031	15 years	100.646(2)	40.8
San Juan	**3**	23 DisCos(1)	January 1, 2018	December 31, 2032	15 years	103.221(2)	272.5
Norvind	**4**	23 DisCos(1)	January 1, 2019	December 31, 2033	15 years	113.221(3)	45.5

(1) CGE Distribución S.A., Compañía Nacional de Fuerza Eléctrica S.A., Empresa Eléctrica Atacama S.A., Empresa Eléctrica de Antofagasta S.A., Luzlinares S.A., Luzparral S.A., Chilquinta Energía S.A., Energía de Casablanca S.A., Compañía Eléctrica del Litoral S.A., Enel Distribución Chile S.A. (formerly Chilectra S.A.), Compañía Eléctrica Osorno S.A., Empresa Eléctrica de la Frontera S.A., Sociedad Austral de Electricidad S.A., Empresa Eléctrica de Casablanca S.A., Cooperativa Eléctrica de Curicó Limitada, Cooperativa de Consumo de Energía Eléctrica de Chillán Limitada, Cooperativa Eléctrica de Los Ángeles Limitada, Cooperativa Eléctrica Paillaco Limitada, Cooperativa Regional Eléctrica Llanquihue Limitada, Cooperativa Rural Eléctrica Río Bueno Limitada, Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Limitada, Compañía Distribuidora de Energía Eléctrica Codiner Limitada and Empresa Eléctrica de Puente Alto Limitada.

(2) Average price from three awarded offers to the specific block.

(3) Price from one awarded offer to the specific block.

The four largest DisCo counterparties (Enel Distribución, CGE Distribución, Chilquinta Energía and SAESA) supply 97% of the total regulated clients of the SEN, and three of these DisCos have an investment grade rated parent company. The table below summarizes the main credit characteristics of these counterparties.

	Compañía General De Electricidad Distribución S.A.	**Enel Distribución Chile S.A.**	**Chilquinta Energía S.A.**	**Sociedad Austral De Electricidad S.A. (SAESA)**
Overview	Formerly known as Gas Natural Fenosa Chile S.A., CGE is a Chile based company founded in 2003 that is principally engaged in the energy sector. The company main activities include transmission and supply of electric energy. CGE business operations are in Chile and Argentina.	Founded in 1921 and formerly known as Chilectra S.A., Enel Distribución operates in the distribution and sale of energy. And is one of the largest electricity distribution company in Chile. Its concession area covers 2,065.4 km², considering 33 communes in the Metropolitan Region, including the capital city Santiago.	Founded in 1889, it operates as an energy supply service company. The company provides installation, transmition, maintenance and distribution of electricity and natural gas. Chilquinta Energia serves customers in Chile.	Founded in 2009, it operates as an electrical power distribution company. The company provides electric energy generation, installation, and distribution through substation power lines. Sociedad Austral de Electricidad serves residential, commercial, and industrial customers in Chile.
Rating	A+ (Fitch) / AA- (Feller) - Local	Not rated	AA (Humphrey's) / AA (Fitch) - Local	AA+ (ICR) / AA+ (Feller) - Local
Parent Company	Naturgy	Enel Chile	State Grid Corporation of China	AIMCO / OTPP
Parent Rating	BBB (S&P) / Baa2 (Moody's) / BBB (Fitch)	BBB+ (S&P) / Baa2 (Moody's) / A- (Fitch)	A+ (A&P) / A1 (Moody's)	Not rated
Number of Clients	3,066,3920	2,008,018	758,739	921,560
Coverage Reach	45%	30%	11%	14%
Energy Sold (GW/h)	10,876	16,481	2,384	3,767
Market Share	33%	49%	8%	10%

PPAs with Unregulated Customers or other power companies can be negotiated directly between the seller and the offtaker and are not subject to the tariff structure defined by National Energy Commission; hence the parties may freely choose a provider and freely agree the energy price. As of the date of this offering memorandum, we have signed 18 PPAs with Unregulated Customers and power companies (three in connection with the San Juan Project and 15 in connection with the Totoral Project), with varied terms and prices.

Our most important individual PPA counterparty is Metro. Our contracted energy with Metro is 75 GW/h per year at US$102.18/MWh. This contract represented 12.0% of our revenue for the three-month period ending March 31, 2021, and 13.1%, 27.9% and 24.8% for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively. The PPA with Metro expires in 2032.

Another important counterparty is Enel Generación for which we provide an annual average contracted energy of 180 GWh (with a "take-or-pay" of 70%, 126 GWh) at US$48.65/MWh under a PPA that is currently set to expire in 2023. Enel Generación is the largest power generation company in Chile, operating 3,468 MW of installed capacity from renewable sources and 2,454 MW of installed capacity from thermal sources, for a total of 6,000 MW of installed capacity. In 2020, its market share in energy sales reached 30.4% of the total energy sold in the SEN and sold 21,811 GW/h. Enel Generación is rated BBB+ by S&P, Baa1 by Moody's and A- by Fitch.

The table below highlights the most relevant features with respect to our most relevant PPAs by group:

	DisCos	Enel Generación	Metro	Other Unregulated Customers
Contracted Energy (GWh per Year)	427(1)	180	75	Incremental from 38 GWh in 2021 to 82 GWh in 2023
Tenor	2031 - 2033	2023	2032	2023 – 2025
Volume Risk	Yes - Take and pay	Yes – 30% take and pay	Yes - Take and pay	Yes - Take and pay
Currency	US$ Denominated	US$ Denominated	US$ Denominated	US$ Denominated
Revenue Streams	Energy Sales	Energy Sales	Energy Sales NCRE Credits	Energy Sales
Energy Dispatch Costs Pass through	Yes - (Transmission and Capacity Charges)	N/A	Yes - (Transmission and Capacity Charges)	Yes - (Transmission and Capacity Charges)

(1) Sum of all DisCo PPAs.

Availability; Production; Generation Capacity

The following tables summarize the average total windfarm availability and power factors for each of the Projects, for the years indicated below:

San Juan Project		
Year	**Availability**	**Power Factor**
2017	93.3%	34.2%
2018	97.4%	34.2%
2019	97.0%	34.5%
2020	95.3%	30.8%

Totoral Project		
Year	**Availability**	**Power Factor**
2017	95.8%	19.0%
2018	96.9%	20.2%
2019	96.6%	20.7%
2020	97.3%	19.6%

The following tables summarize certain production metrics for each of the Projects, for the years indicated below, with a 97% aggregate availability:

<u>San Juan Project</u>

Exceedance probability	**Generation GWh**
P10 (1 year)	625.6
P50	552.1
P90 (1 year)	478.6

<u>Totoral Project</u>

Exceedance probability	**Generation GWh**
P10 (1 year)	92.1
P50	81.4
P90 (1 year)	70.7

San Juan Project

Year	**Production (GWh)**	**Specific Curtailment (GWh)**	**Solved Failure (GWh)**	**Adjusted Generation (GWh)**	**Comments**
2017	553.5	88.0	-	641.5	Major curtailment due to system transmission line capacity
2018	553.3	63.7	-	616.8	Major curtailment due to system transmission line capacity
2019	579.4	21.7	-	599.8	500kV transmission line COD in June 2019, allowing from then the dispatch of all energy
2020	522.8	13.5	29.4	565.0	Curtailment for delayed maintenance of transmission lines supporting the new 500kV. Zigzag transformer overload produced a stoppage in one of San Juan's circuits for 36 days. A spare zigzag was purchased and all of the MV cables were changed from incomer to the LV side of the power transformer.

Totoral Project

Year	**Production (GWh)**	**Curtailment (GWh)**	**Solved Failure (GWh)**	**Adjusted Generation (GWh)**	**Comments**
2017	76.7	10.4	-	87.1	Major curtailment due to system transmission line capacity
2018	81.5	9.1	-	90.6	Major curtailment due to system transmission line capacity
2019	83.2	4.2	-	87.4	500kV transmission line COD in June 2019, allowing from then the dispatch of all energy
2020	79.0	2.7	0.0	81.7	

Wind Resource

Both Projects benefit from a strong and highly predictable coastal wind resource (7.5 m/s for the San Juan Project and 5.6 m/s at the Totoral Project at hub height).

An independent engineer reviewed the wind production at the San Juan and Totoral Projects with data based on actual performance since they began commercial operation. Actual data from the operational period has been scaled to long term expectations based on meso-scale data available for Chile. The tables below summarize the results of the annual energy production assessments.

P Values	1 year average			10 year average		
	San Juan	Totoral	Combined	San Juan	Totoral	Combined
P50	552,1	81,4	633,5	552,1	81,4	633,5
P90	478,6	70,7	549,3	498,5	74,6	573,1
P99	418,6	61,9	480,5	454,7	69,1	523,8

According to the Independent Engineer Report, the external wake loss factor with respect to the San Juan Project from nearby operational assets is 87.6%, presented on a blended basis, which includes actual losses from Cabo Leones I (181.5 MW, operational since June 2018) and Sarco (170.2 MW, operational since July 2020), and estimated wake losses from Cabo Leones III (which began operations in December 2020). According to the Independent Engineer, an extension to Cabo Leones is in construction phase, which is due to commence operation during the next 12 months, based on reports from developers. The San Juan Project does not receive compensation for the wake effect by the other wind projects.

Our Corporate and Ownership Structure

ILAP is a limited liability company (*sociedad de responsabilidad limitada*) formed under the laws of Chile, and is 99.9999% owned by Latin America Power S.A. ("*LAP Chile*"), a corporation (*sociedad anónima*) formed under the laws of Chile, and 0.00001% by Latin America Power Holdings B.V. ("*LAP*"), a Dutch corporation. ILAP owns all but one share in San Juan and all but one share in Norvind, with the remaining share in each case owned by LAP Chile.

LAP owns all but one share of LAP Chile, and Latin America Power Panama S.A. ("*LAP Panama*") owns the remaining share. LAP is a power generation company created with the goal of improving the energy matrix for Chile and Peru through the development of renewable energy sources, while also maintaining close relationships with neighboring communities and protecting the environment. LAP identifies, develops, builds and operates hydro and wind projects. LAP currently owns a total of 10 projects with an aggregate capacity of approximately 342MW.

Our ultimate beneficial owners are:

- ***BTG Pactual Brazil Infrastructure Fund II (45.85%)*** is managed by BTG Pactual Brazil, the leading investment bank in Latin America. It holds approximately US$58 billion in assets under management. BTG Pactual Brazil has an extensive track record in investing in the electrical power through the administration of funds. BTG Pactual Brazil has invested in projects which generate more than 3,500 MW. It was a pioneer in wind power investment in Brazil, through Bons Ventos Park (155 MW). Currently holds a participation in renewables assets, thermal plants and transmission lines. In addition, is a leading financial group with operations in energy trading in Brazil.

- **Patria Investments (Patria)** ***(45.85%),*** which manages the Patria Funds mentioned above, is one of the most traditional alternative investment firms in Latin America. Patria is a pioneer in private equity investments in the region, with over 30 years of experience. The firm currently has over US$ 14.4 billion of assets under management, in funds dedicated to Private Equity, Infrastructure, Real Estate, Public Equities, Agribusiness and Credit Solutions. Patria's infrastructure group, which currently manages US$ 4.7 billion in assets, has significant experience investing in energy. Prior to LAP, Patria co-founded Energías Renováveis S.A. ("*ERSA*"), a leading player in renewables in Brazil, alongside GMR Energía. Patria currently holds interests in CPFL Renovaveis, the largest renewable energy company in Latin America, with a diversified portfolio of hydro, wind, solar and biomass assets. As of December 2020, Patria's Infrastructure Group held interests in 14 companies, including LAP.

- ***GMR Holding B.V. - (8.30%).*** GMR Holding is a Dutch company affiliate of PWR Capital group and holds its investments in Renewable Energy in Latin America.

Our History

LAP was formed in 2011 by a Brazilian entrepreneur named Roberto Sahade, taking advantage of the thriving and efficiently regulated Chilean electrical market, with the goal of developing and operating all-renewable power plants in Chile and other Latin American countries. The first investments were made to purchase water use rights in the south of Chile, and participation in six run-of-river hydro projects in Peru (two of them are still in operation).

In 2013, LAP acquired 100% of the shares of Norvind S.A. from SN Power AS. In parallel, LAP started to develop and seek greenfield projects in order to create a portfolio of generation assets, first in Chile, and later in the neighboring Peru.

In the public auction named "2013-3 Second Call auction" held in 2014, LAP bid energy from the operating Totoral Project and the San Juan Project, which was still in development. As a result of this auction, the Totoral Project was awarded a 15-year contract to supply 45.5 GWh/year to the regulated DisCos from January 1, 2019 to December 31, 2033 and, in the same process, the San Juan Project was awarded 381 GWh/year to supply energy to DisCos for the same period of time.

After securing cash flow stability, LAP entered into turnkey construction agreements with Elecnor, a leading global EPC and renewable energy investor, to build the San Juan Project. The San Juan Project work was completed by Elecnor in September 2016. Vestas, the world's most experienced wind turbine manufacturer, became the provider of wind turbines for both Projects and is also their current O&M service provider. The terms of the O&M Agreements with Vestas guarantee generation availability of 97% per turbine in both Projects, and 98% with respect to the San Juan Project starting 2022. ILAP became the owner of both projects in 2017.

Our principal executive offices and corporate headquarters are located at Cerro El Plomo 5.680, oficina 1202, Las Condes, Santiago, Chile, and our telephone number is +56 2 2820 3200.

Competitive Strengths

Attractive Macroeconomic Fundamentals

Chile offers one of the most business friendly environments in the region: competitive economy, transparent regulatory regime and stable credit status. Chile is rated A by S&P, A1 by Moody's and A- by Fitch. As of 2019, it has a nominal GDP of US$282 billion and a GDP per capita of US$23.6 thousand, with a 7.1% unemployment rate. Chile's public debt as a percentage of GDP is 36%. As of 2019, it showed a diversified economic activity, led by the services industry (39%), followed by industrials (14%), mining (10%) and construction (10%).

Proven Assets with Stable and Predictable Wind Resource and Best-in-Class Design

The San Juan Project began partial operations in July 2016 and achieved full commercial operation in March 2017. The Totoral Project began commercial operations in January 2010. Both Projects benefit from a strong and highly predictable coastal wind resource (7.5 m/s at the San Juan Project and 5.6 m/s at the Totoral Project at hub height). Both Projects utilize Vestas wind turbines, which offer best-in-class design and technology. Vestas is a market leader with 136 GW of installed capacity worldwide, over 40 years of experience and more than 80,000 turbines installed and connected to date, 443 of them in Chile with a generation capacity of 1,044 MW. The San Juan Project operates 56 Vestas V117-3.45 MW wind turbines, designed to be installed at medium or high wind sites, maximizing generation for wind speed. The wind performance at the San Juan Project was improved by the incorporation of a PowerPlus upgrade package offered by Vestas in the base case, which increased the energy production per turbine from 3.3 MW to 3.45 MW, increasing therefore the installed capacity from 184.8 MW to 193.2 MW. The Totoral Project operates 23 Vestas V90-2.0 MW wind-turbines to be low weight with a lower load to reduce foundation costs without sacrificing durability or impacting asset life. The V90-2.0 MW blades are one of the lightest 44 m blades in the market maximizing availability and wind generation during moderate wind periods. All the major components have been designed to allow for fast and efficient repair and have undergone highly accelerated lifetime tests. The technology allows for an asset life extension strategy backed by a detailed long-term O&M program and preventative maintenance plan with Vestas.

Highly-rated PPA Counterparties

Throughout the term of the Notes, we expect that our revenue will consist of approximately 92% from Contracted Customers, including DisCo PPAs, Unregulated Customers PPAs, NCRE (non-conventional renewable energy) contracts and capacity payments. The weighted average rating of the DisCo obligors is "AA-" on the Chilean local scale (equivalent to "BBB" in the international scale), and the overwhelming majority of the DisCo obligors are owned by large, highly-rated international strategic companies (Naturgy, Enel, State Grid, AimCo & Ontario Teachers' Pension Plan). The Chilean DisCos operate as natural monopolies, of which the largest four DisCos (Enel Distribución, Chilquinta Energía, CGE Distribución and SAESA) account for approximately 97% of the total regulated clients of the SEN and maintain local investment grade ratings. In addition, the Metro contract serves as a natural hedge against the risk that the DisCos are over-contracted, as any additional generation at the San Juan Project beyond the amount sold through the DisCo PPAs is available to be sold to Metro, Enel Generación, Cinergia, other potential new PPA client, or the spot market.

In aggregate, the DisCo PPAs represent stable contracted cash flows that are Dollar denominated, inflation indexed, and diversified across a series of market participants providing a critical service through a monopolistic distribution network. This combination of Contracted Customers creates a diverse set of cash flows with limited exposure to any single counterparty. Furthermore, there are special rules and procedures in place to ensure business continuance in case of a DisCo's insolvency or concession revocation. The latter supports the Projects' operational stability, because our operations may rely on stable and predictable market conditions in which all the off-takers are subject to the same set of rules.

Industry Leading O&M Support and Appropriate Insurance Coverage

We use state of the art industry leading O&M support. We have developed and implemented a unified system and preventative maintenance plan for all aspects of electrical, technical and design maintenance by signing comprehensive O&M Agreements with Vestas and subcontracting specialists to enhance O&M support. The contracts include 24/7 monitoring, control and operation, including preventive and corrective maintenance, and unscheduled maintenance due to failures, breaks or under performance not as a result of any excluded event. It also includes O&M expenses such as workforce, spare parts, consumables, tools and lifting equipment. Vestas will perform the scheduled and unscheduled maintenance of the San Juan and Totoral Projects through 2037 and 2029, respectively, under the current contracts, which guarantee 97% availability per turbine for both Projects (98% availability in the San Juan Project starting 2022), subject to financial penalties.

Both Projects have insurance coverages that are in line with those of similar assets and industry standards, adequate to properly mitigate for the operational risks of the Projects. According to the Independent Insurance Advisor the Company has property damage and business interruption coverage with an aggregate total value of US$552,336,542, and general liability and D&O insurance coverage in line with markets standards.

Transparent Market with Significant Regulatory Oversight

Since the liberalization of the electricity market in 1982, the Chilean power industry has undergone significant regulatory changes, consistently increasing transparency and competition in the marketplace, including mechanisms for long-term contracts to supply Regulated Customers, the introduction of a spot market, stable capacity markets and NCRE revenues. The combination of these revenues creates a diversified cash flow profile that is supportive of long-term financing and asset development. These changes to the Chilean power industry have resulted in a stable and favorable regulatory environment for independent power producers like us.

Our Projects consist in NCREs, which Enjoy Strong Governmental Support under the NCRE Law

Recent legislation in Chile supports the increased development of renewable generation resources compared to other technologies that may rely on fossil fuels or that may release carbon emissions to the atmosphere. The NCRE Law, encourages the development of non-conventional renewable energy units by requiring that a certain amount of electric power withdrawn by power companies be generated by NRCEs (20% by 2025), reflecting Chile's commitment to renewable generation and increasing renewable energy demand growth to 13.6% annually through 2025 to comply with regulations. The NCRE Law created an NCRE credits market and a penalty applicable to generation companies that do not meet the minimum NCRE generation amount or do not purchase sufficient NCRE credits. In 2019, the Chilean government and the largest companies having interests in coal-fired generation (Enel, AES Gener, Engie and Colbún) reached a voluntary agreement (as further developed in 2020) not to initiate the construction of new coal-fired power plants and to work on a progressive decommissioning schedule to dismantle those facilities by 2040. This agreement has further encouraged the development of NCRE projects to replace the coal-fired power plants being decommissioned. These and other programs that may arise in the future, showcase the Chilean government's commitment with renewable energy.

Market Design Supports Contracted Revenues

In May 2005, the Ministry of Economy instituted Short Law II requiring DisCos to participate in a competitive tender/auction process to secure their electricity supply through long-term fixed price contracts. The goal was to address uncertainties regarding future electricity supply by establishing volume requirements, setting fixed prices for medium and long-term supply and predicting demand three years in advance. In 2015, the Energy Tender Process Reform (Law 20,805) was enacted to improve the tender process and limit/prevent oversupply conditions. In order to do so, the auction structure tied the DisCo revenue to their demand forecasting accuracy via the VAD tariff; DisCos receive revenue based on how closely they can predict their energy demand relative to a "model" company.

Demand shortfall is distributed pro rata throughout all DisCo PPA contracts and the generation impact is shared proportionately by all of the DisCos. The PPA contracts therefore provide stability due to the shared risk amongst all the DisCos, creating a low likelihood of systemic default within the DisCo market. The DisCos have also been historically resilient and only one major DisCo has defaulted on its contracted agreements since the implementation of the auction and contracting reform. The risk associated with the San Juan and Norvind DisCo PPAs is mitigated by distributing sales of energy across 67 PPAs with 23 counterparties, which participated in the 2013-3 Second Call auction.

The market design has anticipated critical risks that would otherwise disincentive investors from participating in the Chilean market. Currency risk is mitigated through Dollar indexed PPAs. Inflation risk is reduced through the CPI or U.S. CPI index. Counterparty risk is reduced through distribution across multiple DisCos as well as through a mechanism allowing the government to intervene in the event of DisCo insolvency. The stability of contracted revenues creates a highly resilient cash flow profile, supplemented by capacity revenues, NRCE contracts and a strong spot market. In addition, the Unregulated Customer PPA market is broad and efficient enough to allow generating companies to counter mid-term oversupply situations by signing bilateral contracts with energy retailers or end customers, therefore reducing the spot market exposure. We believe all these factors will enable us to ensure regularity of cashflows available for debt service payments through 2031.

Experienced Key Management Team

Our senior management team has extensive experience in the development and operation of renewable energy in Chile, with more than 18 years on average of experience in the energy industry in Chile and Latin America, playing several roles as developers, partners and board members in different renewable energy companies. We benefit from our parent companies' experience in developing, owning and managing renewable assets in Chile and the region, and our representatives participate actively in industry groups such as the Chilean Generators guild (*Generadoras de Chile*), a trade association formed by the largest power generation companies in the country. Additionally, we have a dedicated internal team of technicians which work closely with Vestas providing support including administration and oversight over the period in which the manufacturer is responsible for the maintenance of the turbines.

Business Strategy and Objectives

Provide world-class service quality while operating our Projects safely, efficiently and sustainably

We strive to provide world-class quality of service while operating our facilities safely, efficiently and sustainably. Our business adheres to global benchmarks for safety, environmental and operating standards in the industry and we promote a culture of health, safety, accident prevention, security and environmental excellence by our employees, contractors and local communities. We are continually exploring the implementation of efficiency measures and renewable energy generation technologies in order to enhance the overall operational efficiency and sustainability of our Projects. We also follow strict corporate governance standards and seek to ensure fairness, transparency, accountability, and responsibility in the operation of our business for our owners and all stakeholders.

Maintain a solid financial profile with stable and predictable cash flows

We are committed to maintaining a solid financial profile, strong credit metrics, and providing stable returns to our owners. Our principal financial objectives include generating predictable and stable cash flows, maintaining adequate minimum liquidity and managing our debt amortization schedule in line with the tenor of our PPAs. Our business model, based on long-term PPAs covering our generation capacity in the long-term, protects us against electricity price fluctuations in addition to fluctuations in our variable costs and exchange rates.

Achieve Financial Excellence

Our financial policy focuses on profitability, stability and liquidity in order to maintain and develop our business and drive profitability. Our principal financial objectives include balancing our capital structure, maintaining an adequate liquidity and having a debt amortization schedule according to our cash flow generation to prevent cash flow and earnings volatility. The proceeds of this offering of Notes will be mainly used to satisfy in full all of our obligations under the NPA, to further reorganize our liabilities in the long term.

Maximizing Efficiency and Asset Life

We continue to improve and maintain our assets to optimize efficiency and cost effectiveness of operations on a day-to-day basis, as well as to maximize the lifespan of our assets, by ensuring proper O&M and applying industry best practices. We use state-of-the-art technology for the control and monitoring of our Projects with services rendered by leading companies like Nispera and Saroens, which allow us to predict our generation availability with better accuracy and anticipate system failures. See "*Our Business—Equipment and Technology*." Through the implementation of updated technologies and employee training programs in maintenance and operations of the Projects, together with maintaining our O&M Agreements AOM4000 with Vestas, we continue to modify our strategies and procedures to enhance asset operational reliability and life expectancy.

Maintain Constructive Relationships with Government Regulators and the Community

We continue to build and maintain constructive relationships with government regulators and local communities where our assets are located, with a focus toward mutually beneficial relationships with all parties involved in the operation and maintenance of our Projects, as well as those involved in the generation and sale of energy. In 2020, we were awarded first place for "good practices" in an annual contest held by the Chilean Generators guild (*Generadoras de Chile*), due to our management of relationships with communities. Our management policies are certified under the ISO9001:2015 standards.

Summary of Findings from Independent Engineer Report

The Independent Engineer prepared the Independent Engineer Report, a copy of which is attached as Appendix A to this offering memorandum. Below is a summary of the key findings of the Independent Engineer Report:

- The Projects have benefited from high levels of availability and production compared to budget expectations and performance has improved as the Company worked through minor ramp-up equipment issues, as would be expected in the early stages of these projects. Vestas contractually guarantees availability of the turbines at 97% for both sites. In 2021, this availability requirement will increase to 98% for San Juan. These levels of availability have consistently been achieved.

- The Projects have both encountered some losses, including grid curtailment, which would be expected in the early part of operations. Importantly, a new transmission line (Cardones-Polpaico

500 kV) was completed in 2019 and has reduced the level grid curtailment in 2020. The Independent Engineer notes that no formal log of curtailment is provided from the grid. However, the Independent Engineer recommends that the Company improve their method for quantifying and logging outages, which will help to isolate issues within the facility from true grid curtailment. Other minor breakdowns are considered by the Independent Engineer to be isolated events, which management has rectified and appropriate assumptions for future availability are included in the yield assessments for both projects.

- The Independent Engineer has undertaken an independent yield assessment for the two Projects, using industry-standard approaches. For Totoral, historical operating information from the period 2017-2020 was used to develop a post-construction yield assessment. The Independent Engineer's analysis indicates an average Net Yield of 81.4 GWh/ year (P50) and a 1-year P90 of 70.7 GWh.

- For San Juan, the Independent Engineer found that there has been a complicated ramp-up period: as new windfarms have been constructed between 2017 and 2020. While the Independent Engineer's post-construction yield assessment takes these effects into account, the 'clean' operating period is relatively short. The Independent Engineer considers there remain some uncertainties in the post-construction approach and so a blended pre-construction and post construction yield assessment has been used.

- The Independent Engineer's analysis indicates an average Net Yield of 552.1 GWh/ year (P50) and a 1-year P90 of 478.6 GWh. These values take into consideration the likely wake-losses from nearby development, Cabo Leones III, which began operation in December 2020, Sarco (2018), and Cabo Leones I (2020).

- The Company has an appropriate O&M/asset management approach, with an in-house staff covering both wind farms and some central resources to support other projects in the region. The Company benefits from a cloud-based maintenance management system and remote monitoring of the assets via SCADA to a control room situated in Santiago, Chile.

- There are opportunities for improvement to the Company's overall O&M approach, which the Company has indicated they intend to take, including better monitoring of production losses to help improve performance as well as a more robust inspection program, particularly for towers and foundations.

- Based on the information provided, the operating assets of the two Projects appear to be operating satisfactorily and are well-maintained. For the wind turbines and towers, the Vestas O&M contract provides a high-quality service to monitor and maintain this equipment. There have been a few, minor operating defects since start of operations, which Vestas have resolved.

- The San Juan Project suffered from a zig-zag transformer failure in July 2020, causing a partial outage for 36 days. This has been investigated and appeared to arise from combination of technical and operating factors. Measures are in place to ensure this issue be mitigated in future.

- The foundations for the wind farm are a key component in the overall project and the expected useful life of the asset. Should any problems arise during the operational phase, these can often be uneconomic to repair. The validation of an appropriate design and verification of construction quality are important to ensure that a useful life of more than 20 years for the foundations can be expected. Although no fundamental flaws have been identified with the design, a high-level review has shown that the fatigue analysis in the design phase was limited. The Independent Engineer therefore recommends that the Company should undertake a fatigue analysis, which the Company management has indicated they intend to undertake. The Independent Engineer recommends a downside sensitivity case to consider a 2% production curtailment from year 15 onwards to ensure that fatigue loads remain within the design-envelope of the foundations.

- The Independent Engineer understands that the Company is discussing life-extension with Vestas for the tower and wind turbine generators once the existing contracts expire (Totoral, March 2029; San Juan, March 2037). This is a reasonable strategy. Considering the appropriate maintenance strategy in the meantime, the Independent Engineer believes that from a commercial point of view, sufficient budget has been built in the financial model for the wind farms to operate for 30 years.

The summary of conclusions of the Independent Engineer Report above is qualified in its entirety by the report itself, which you should read before making an investment in the Notes. The Independent Engineer is an independent consultant with experience in the industry. For purposes of preparing its report, the Independent Engineer relied on information provided by us as well as government agencies.

Summary of Findings from Market Consultant Report

The Independent Market Consultant prepared the Independent Market Consultant Report, a copy of which is attached as Appendix B to this offering memorandum. This report, among other things, provides context on (i) the Chilean electricity market, explaining the regulatory framework with the most important laws that govern the market relevant to the Projects, (ii) the main entities and segments in the Chilean electricity market, (iii) market perspectives, methodological aspects for energy price projections and capacity credit estimation, (iv) ILAP's portfolio characteristics, (v) a review of the most relevant PPAs of both Projects, and (vi) the results of marginal cost projections and capacity credit projections. Below is a summary of the key findings of the Independent Market Consultant Report:

- The report notes that the San Juan Project has an installed capacity of 193.2 MW made up of 56 turbines, the second largest wind farm in Chile. The Totoral Project has an installed capacity of 46 MW made up of 46 Vestas V90/2.0 MW wind turbines. Located near the coast, the San Juan Project has a good capacity factor and relatively predictable generation cycle, whereas Totoral Project has a more unpredictable generation. In 2020, the San Juan Project generated 504.6 GWh, and the Totoral Project generated 79.5 GWh.

- The Independent Market Consultant Report describes recent updates to the Chilean electricity system. According to the Independent Market Consultant, Chile is in a period of transformation or transition associated with trends such as an increase in the participation of variable renewable generation sources, increasing participation of distributed generation, energy storage, among others. The changes that are contemplated include the incorporation of a new concept of "Flexible Capacity" to satisfy the needs of the flexibility of the systems concerning the ramps of the system, as well as the incorporation of modifications that integrate better "demand signals" for the determination and contribution to the sufficiency power, among others.

- The report also addresses the effects of the COVID-19 pandemic in the Chilean electricity market. The Independent Market Consultant explains that such effects can be observed in two main areas: on the one hand, there is a variation in electricity consumption. The report provides data showing that the percentage increase of residential demand of electricity from March to September 2020 ranged from 100% to 270%. On the other hand, the pandemic has caused delays in construction of electrical infrastructure. Of about 5,000 MW of generation under construction, projects currently representing almost 2,800 MW have delays, approximately 55% of the projects.

- The report provides monthly marginal cost and capacity projection results for five nodes: Crucero 220 kV, Maitencillo 220 kV, Las Palmas 220 kV, Quillota 220 kV and Charrúa 220 kV. It divides the data into Base Scenario and Downside Sensitivity. Under Base Scenario, the report concludes as follows: the expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 48.6 US$/MW; the expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 45.7 US$/MWh; the expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 45.5 US$/MWh; the expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 47.6 US$/MWh; the expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh.

Under the Downside Sensitivity scenario, the report concludes as follows: the expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 38.6 US$/MW; the expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 37 US$/MWh; the expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 36.8 US$/MWh; the expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 38 US$/MWh; the expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh.

- The report concludes that the installed capacity of the SEN as of February 2021 totaled 26,376 MW. Thermal installed capacity, counting coal, natural gas, and diesel technologies have a share of 48.7% of the total installed capacity of the SEN. Hydro powered units (run-of-river and dam units) add up to 25.9% of the total installed capacity, while solar PV and wind-based technologies represent 23.3% of the SEN's installed capacity. The "big four" generating companies (Enel, AES Gener, Colbún, and Engie) own 60.9% of all the installed capacity of the SEN; however, given the increase in competitivity that has been seen during the last tendering processes for regulated and unregulated clients, the market share has diversified and permitted the entry of new competitors. Regarding the transmission segment, the main company is Transelec, with 27.6% of the market share. CGE and Interchile come afterwards with 10.7% and 5.5%, respectively. Transelec, CGE, Interchile, ENGIE, Colbún Transmisión, Minera Escondida, AES Gener, TEN, Chilquinta, STS and Enel Transmisión Chile form 70.9% of the whole market share. In the remaining 29.1%, there are 176 additional companies, totaling 187 transmission companies operating in the SEN.

- Finally, the report discusses the general methodology and main input data. It describes the main input data corresponding to the methodologies on which the projection of commercial revenues and costs are based. The data correspond to generation and transmission expansion plans, a decarbonization plan, fuel price projection, LNG availability and demand projection. In addition, methodological aspects related to energy marginal cost projection, capacity recognition projection are also addressed.

The summary of conclusions of the Independent Market Consultant Report above is qualified in its entirety by the report itself, which you should read before making an investment in the Notes. The Independent Market Consultant is an independent consultant with experience in the industry. For purposes of preparing its report, the Independent Market Consultant relied on information provided by us as well as government agencies.

The Chilean Power Market

The main electricity system in Chile is the SEN, which was created through the interconnection, in November 2017, of the formerly known Central Interconnected System or SIC and the Northern Interconnected System or SING, which supplies electricity to over 99% of the national population, with a length of 3,100 kilometers, and is the interconnected system between Arica (*Región de Arica y Parinacota*), and Chiloé (*Región de Los Lagos*). Additionally, there are a number of medium and small electricity systems in the regions of Los Lagos, Aysen and Magallanes and one small system on Easter Island, none of which have an aggregate capacity higher than 200 MW.

The SEN power grid featured gross installed capacity amounting to 26,310.4 MW as of December 31, 2019. Maximum hourly gross demand in the twelve-month period ending December 31, 2020 came to 10,907.2 MW and total generation in the SEN in the same period amounted to 58,034 GWh.

In the SEN, electricity generation is coordinated by a system operator, the National Electrical Coordinator, whose main purpose is to minimize operational costs and to ensure the highest economic efficiency of the system, while meeting all service quality and reliability requirements established by law. Since the Transmission Law, the National Electrical Coordinator is also in charge of tracking and monitoring competition in the electricity industry and safeguarding open access to electricity transmission. The National Electrical Coordinator also has a complementary role in planning the expansion of transmission.

The Chilean electricity industry is divided into three business segments: generation, transmission and distribution. In general terms, generation is subject to market competition, while transmission and distribution, given their natural monopoly character, are subject to price regulation. Final customers may be regulated or unregulated depending on their connected capacity. Only Unregulated Customers may freely choose a provider and freely agree the energy price. Regulated Customers are forced to contract with DisCos and pay them a tariff defined by National Energy Commission.

The generation segment is comprised of companies that own generating plants, whose energy is transmitted and distributed to end customers. Generation companies produce electricity and sell their production at the spot market price, which is calculated on an hourly basis by the National Electrical Coordinator, based on the marginal cost of production of the most expensive kWh dispatched.

Power generation companies satisfy their contractual sales requirements with dispatched electricity, whether produced by them or purchased from other generation companies in the spot market. The principal purpose of the National Electrical Coordinator in operating the dispatch system is to ensure that only the most cost-efficient electricity is dispatched to customers. The National Electrical Coordinator dispatches plants in the order of their respective variable cost of production, starting with the lowest-cost plants, such that electricity is supplied at the lowest available cost. Generators balance their contractual obligations with their dispatches by buying or selling electricity at the spot market price, which is calculated on an hourly basis by the National Electrical Coordinator, based on the marginal cost of production of the most expensive kWh dispatched.

All generators can commercialize energy through contracts with distribution companies for their Regulated Customers and Unregulated Customers, or directly with Unregulated Customers or other generation companies. All contracts executed between generation and DisCos for the supply of Regulated Customers after 2005 must be the result of open, competitive and transparent auction processes. Generators may also sell energy to other power generation companies on a spot price basis. Power generation companies may also engage in contracted sales among themselves at negotiated prices, outside the spot market. Contract terms are freely determined (except in the case of supply to Regulated Customers).

Final customers are classified according to their installed capacity, as follows: (i) Unregulated Customers with connected capacity of over 5,000 kW; (ii) Regulated Customers with connected capacity up to 500 kW; and (iii) customers that choose either a regulated tariff or an unregulated regime for a minimum period of four years, available to customers whose connected capacity falls in the range of 500 kW to 5,000 kW.

Recent Developments

Impact of COVID-19 Pandemic

Since the beginning of the COVID-19 pandemic in the first quarter of 2020, energy demand in the Chilean electricity market has decreased as a result of the pause, reduction or discontinuation of certain industrial and mining operations and limitations to local and international travel.

Beginning in March 2020, the Chilean government, the Central Bank and the CMF announced a series of measures aimed at mitigating the effects of COVID-19 on the Chilean economy. On April 2, 2020, the Central Bank published its monetary policy report for the month of March, modifying its GDP forecasts. The Central Bank estimated GDP contraction between 5.5% and 7.5% of GDP for 2020 and GDP growth between 4.75% and 6.25% for 2021 and between 3.0% and 4.0% for 2022. However, actual economic results may differ materially from these estimates.

Since the first quarter of 2020, we have taken steps to prevent the spread of the virus following the guidelines and recommendations from health authorities, including social distancing protocols and remote working, which has allowed us to maintain normal operations and protect the health and safety of operators and administrative personnel.

Tariff Stabilization Law and PEC

As a result of the social unrest that began in Chile in October 2019, the Tariff Stabilization Law was enacted in November 2019 to temporarily stabilize electricity prices for Regulated Customers, by rescinding a recent increase in electricity tariffs payable by Regulated Customers and effectively preventing us from collecting revenues at the levels set forth in our existing PPAs. See "*Legal and Regulatory Framework—Tariff Stabilization Framework*."

The main purposes of the Tariff Stabilization Law are (i) to unwind the 9.2% electricity tariff increase which came into effect on October 10, 2019; and (ii) to avoid future increases on tariffs that Regulated Customers pay to DisCos, temporarily stabilizing tariffs between July 1, 2019 and December 31, 2020 at the rates in effect on June 30, 2019. Tariffs applicable as of June 30, 2019 are known as the Regulated Customer stabilized price (*precio estabilizado a cliente regulado*), or PEC. In addition, the Tariff Stabilization Mechanism provides that the PEC may be adjusted only for inflation by the CPI from January 1, 2021, to December 31, 2024. The PEC so adjusted for inflation, is known as the Adjusted PEC. The cost of the Price Stabilization Mechanism will be borne by the generation companies because DisCos will pay the prices established by the rules issued by the CNE and not those prices previously agreed with the generation companies in PPAs currently in effect. Other contractual indexations such as U.S. CPI, exchange rate differences or fuel price changes are not considered in PEC adjustments. See "*Legal and Regulatory Framework—Tariff Stabilization Framework*."

Since the enactment of the Tariff Stabilization Law, DisCos have paid (and will pay) their suppliers the lower of (a) the PNLPs, or (b) the PECs or Adjusted PECs set out in each Tariff Decree. If, as a result of the Tariff Stabilization Mechanism, the PEC or Adjusted PEC applicable during a Tariff Period is lower than the PNLP that would otherwise have applied during that Tariff Period by a DisCo to a generating company under a PPA were the Tariff Stabilization Mechanism not in effect, the difference between that PEC or Adjusted PEC and that PNLP will constitute an unpaid balance (*saldo*), and the Ministry of Energy will be required to recognize it in the subsequent Tariff Decrees as a receivable, creating a PEC Receivable payable by that DisCo to that generating company. The Tariff Stabilization Mechanism will be in effect from July 1, 2019 until the earlier of (a) December 31, 2027, and (b) the date on which the PEC Receivables have been paid in full.

While the Tariff Stabilization Law will create a mechanism to record and recover any differences between PPA prices and stabilized prices under the Tariff Stabilization Framework via PEC Receivables, in the short term, we expect our revenues to decrease, at a minimum, by the amount corresponding to the difference between our PPA prices and the PEC determined under the Tariff Stabilization Framework. The Tariff Stabilization Framework, or other future legal or regulatory intervention in the determination of energy prices in the Chilean market, could cause us to have a cash flow shortfall, negatively affecting our results of operations and our ability to make payments under the Notes. See "*Risk Factors—Risks Related to the PEC Receivables*" below for a more detailed description of risks associated with the recording, collection and enforcement of PEC Receivables.

Refinancing Transaction

In September 2017, we entered into an agreement with private investors for the issuance of a US$412,000 thousand bond to refinance the existing debt in connection with the construction of the San Juan Project and the Totoral Project, associated break costs, provide funding for reserve accounts, pay fees, expenses, make distribution to our owners and for general corporate purposes. The bonds issued under the NPA bear a fixed interest rate of 5.35% *per annum*, and mature in March 2033. The obligations under the NPA are secured by the assets of San Juan and Norvind, the contractual and collection rights under the PPAs, certain transaction accounts in Chile and the U.S., and the shares in each of ILAP, San Juan and Norvind.

On May 5, 2021, we entered into an amendment to the NPA under which all investors agreed, among others, to a reduction in the make-whole premium amount set forth in the NPA, provided the Issue Date occurs on or before June 15, 2021.

The outstanding amount under the NPA as of March 31, 2021, is US$389,235 thousand, which we expect to repay in full on the Issue Date with the proceeds of the issuance of the Notes together with all associated make-whole premium and accrued interest. See "*Use of Proceeds*." We expect to release all collateral securing the notes issued under the NPA simultaneously with the issuance of the Notes.

Green Bond Principles

We intend to allocate an amount equivalent to the net proceeds from the sale of the Notes (less certain transaction expenses) into projects that may qualify as eligible green projects under the GBP and GLP, and refinance in whole existing debt incurred in connection with the Projects consisting in two wind farms in northern Chile. The Projects support activities related to renewable energy, energy efficiency, and energy affordability as described in this offering memorandum.

The GBP are voluntary process guidelines for the issuance of green bonds, developed by a committee of issuers, investors and other participants in the social, green and sustainability bond markets, with the International Capital Market Association acting as Secretariat. We have obtained a Second Party Opinion from a consultant with recognized environmental and social expertise on the environmental benefits of the use of proceeds described herein as well as its alignment to the GBP. We believe the process described in the section "*Use of Proceeds*" below is in alignment with the GBP and GLP.

We have assumed certain annual reporting obligations, as further described under "*Use of Proceeds*" below. The issuance of these reports does not imply a contractual obligation, and breach of this undertaking may not constitute a default or event of default under the Notes. Further, we may decide to change our reporting undertakings or not comply with these reportings at any time.

THE OFFERING

The following is a brief summary of certain terms of this offering. For a more complete description of the terms of the Notes, see "Description of the Notes" in this offering memorandum. See "Description of the Notes" for capitalized terms used but not defined in this summary.

Issuer .... Inversiones Latin América Power Ltda., a limited liability company (*sociedad de responsabilidad limitada*) formed under the laws of Chile.

Guarantors .... The Notes will be fully and unconditionally, jointly and severally, guaranteed by each of the Issuer's direct and indirect subsidiaries, including San Juan S.A. and Norvind S.A. (each, a "*Guarantor*" and, together, the "*Guarantors*").

Notes .... U.S.$403,900,000 million aggregate principal amount of 5.125% Senior Secured Notes due 2033. The Issuer may issue additional Notes from time to time, which additional Notes will form part of the same series as the Notes for all purposes under the Indenture, if certain conditions are satisfied.

Issue Price .... 99.997%, plus accrued interest, if any, from June 15, 2021.

Final Maturity Date........................... June 15, 2033.

Amortization of Principal .... The principal of the Notes is payable in semi-annual installments on each Note Payment Date.

Scheduled Payment Dates	Scheduled Principal Amount (thousands of US$)
03 January, 2022	3,546.00
03 July, 2022	4,754.00
03 January, 2023	4,370.00
03 July, 2023	3,417.00
03 January, 2024	6,127.00
03 July, 2024	4,339.00
03 January, 2025	7,100.00
03 July, 2025	7,632.00
03 January, 2026	10,659.00
03 July, 2026	9,022.00
03 January, 2027	12,228.00
03 July, 2027	10,815.00
03 January, 2028	13,347.00
03 July, 2028	12,263.00
03 January, 2029	14,736.00
03 July, 2029	12,661.00
03 January, 2030	14,037.00
03 July, 2030	13,828.00
03 January, 2031	15,177.00
03 July, 2031	14,735.00
03 January, 2032	16,274.00

03 July, 2032	12,173.00
03 January, 2033	12,996.00
15 June, 2033	167,664.00

Target Debt Balance.......................... On every scheduled payment date, and to the extent of Available Cash (as defined herein), the Issuer will be required to redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed based on a Target Debt Balance amount as of the date of determination, without premium.

Scheduled Payment Dates	Target Debt Balance (thousands of US$)
03 January, 2022	397,761.00
03 July, 2022	390,221.00
03 January, 2023	383,564.00
03 July, 2023	377,599.00
03 January, 2024	368,994.00
03 July, 2024	362,170.00
03 January, 2025	352,259.00
03 July, 2025	339,061.00
03 January, 2026	322,947.00
03 July, 2026	307,872.00
03 January, 2027	289,671.00
03 July, 2027	272,124.00
03 January, 2028	252,561.00
03 July, 2028	237,957.00
03 January, 2029	220,196.00
03 July, 2029	202,797.00
03 January, 2030	183,503.00
03 July, 2030	164,423.00
03 January, 2031	143,607.00
03 July, 2031	123,262.00
03 January, 2032	100,875.00
03 July, 2032	82,052.00
03 January, 2033	62,039.00
15 June, 2033	49,511.00

Interest.. Interest on the Notes will accrue from the date of issuance until the final maturity date of the Notes, at the rate of 5.125% per annum, payable semi-annually in arrears in cash on each January 3 and July 3, commencing on January 3, 2022. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

Use of Proceeds .... We estimate that the net proceeds from the sale of the Notes will be approximately US$392 million after deduction of fees and expenses. We intend to use the entirety of the proceeds from the sale and issuance of the

	Notes to finance or refinance a pool of renewable energy projects that meet certain green energy guidelines. For more information, see "*Use of Proceeds*."
Additional Amounts	Any and all payments of principal of, premium, if any, and interest on or with respect to the Notes, by or on behalf of the Issuer, to noteholders, will be made free and clear of, and without withholding or deduction for or on account of, Taxes imposed by any Taxing Jurisdiction, unless required by Applicable Law, subject to certain exceptions. For more information, see "*Description of the Notes—Additional Amounts*."
Note Guarantees	The Guarantors will fully and unconditionally, jointly and severally, guarantee all of the Issuer's obligations under the Notes. The Note Guarantees will be subject to contractual and legal limitations under relevant local law and may be released under certain limited circumstances.
Ranking	The Notes and the Note Guarantees will be the senior obligations of the Issuer and the Guarantors, will rank equally in right of payment with all of the Issuer's and the Guarantors' existing and future senior indebtedness, effectively senior to any existing and future unsecured indebtedness (to the extent of the value of the collateral securing the Notes and the Note Guarantees) and senior to any of the Issuer's or the Guarantors' future subordinated indebtedness. On, before or after the Issue Date, the Issuer intends to enter into a Letter of Credit Facility Agreement with Citibank, N.A. for purposes of issuing one or more standby letters of credit to fund the Debt Service Reserve Account and the O&M Reserve Account (as defined herein). The Issuer's obligations under the LC Facility Agreement would rank *pari passu* with the Notes, be secured ratably by the Collateral and be jointly and severally guaranteed by the Guarantors.
Optional Redemption	*Optional Redemption prior to July 3, 2028*. At any time prior to July 3, 2028, the Issuer may redeem the Notes, in whole or in part, at a "make-whole" redemption price equal to the greater of (1) 100% of the principal amount of the Notes being redeemed and (2) the present value at such redemption date of all required interest and principal payments on such Notes through the final maturity date (excluding accrued but unpaid interest to, but excluding, the redemption date), plus any accrued and unpaid interest and additional amounts to, but excluding the date of redemption, discounted at the treasury rate plus 50 basis points. *Optional Redemption on or after July 3, 2028*. At any time and from time to time on or after July 3, 2028, the Issuer may redeem the Notes, at its option, in whole or in part, at the following redemption prices, expressed as percentages of the principal amount on the redemption date, *plus* Additional Amounts and accrued and unpaid interest to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant scheduled payment date to the extent that such date precedes the redemption date), if redeemed during the twelve-month period beginning on July 3, 2028, of each of the years set forth below:

Year	Percentage
2028 …………………………………………..	102.5625%
2029 …………………………………………..	101.7083%
2030 …………………………………………..	101.28125%
2031 and thereafter …………………………..	100.0000%

Optional Redemption upon Equity Offerings. Prior to July 3, 2024, the Issuer may, at its discretion, at any time or from time to time, use an amount not to exceed the net cash proceeds of one or more Eligible Equity Offerings to redeem up to 35% of the aggregate principal amount of the outstanding Notes (including any Additional Notes) at a redemption price equal to 105.125% of the principal amount on the redemption date, plus any accrued and unpaid interest to, but excluding, the redemption date subject to certain restrictions.

Optional Tax Redemption. The Issuer may redeem the Notes in whole but not in part at any time, at its option, at a redemption price equal to 100% of the principal amount of the Notes being redeemed, plus accrued and unpaid interest and Additional Amounts, if any, on such Notes to, but excluding, the redemption date, if, as a result of certain changes to the applicable laws, treaties or regulations that cause the Issuer to be obligated to pay Additional Amounts in excess of the Additional Amounts initially payable on the Notes. See "*Description of the Notes—Optional Redemption*."

Change of Control Offer.................. If a Change of Control occurs, the Issuer will be required to offer to purchase all of the Notes at 101% of the principal amount thereof, together with accrued and unpaid interest and additional amounts, if any, to, but excluding, the date of purchase. See "*Description of the Notes—Offers to Purchase—Change of Control*."

Cash Sweep Mandatory Redemption .... Upon each scheduled payment date, the Issuer will redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed, plus accrued and unpaid interest to the redemption date, plus Additional Amounts, if any (but without payment of any "make-whole" premium) in an amount equal to the lesser of: (i) 100% of Available Cash (if any) and (ii) the total outstanding principal of the Notes as of such scheduled payment date less the applicable Target Debt Balance corresponding to such scheduled payment date (calculated after accounting for any principal payment made on such scheduled payment date), subject to certain restrictions. See "*Description of the Notes—Cash Sweep Mandatory Redemption*."

Excess Disposition Offer .... Upon the occurrence of Dispositions of assets, the Issuer shall be required to offer to apply any Excess Disposition Proceeds to purchase the Notes at 100% of the principal amount thereof, together with accrued and unpaid interest and additional amounts, if any, to, but excluding, the date of purchase. We will not be required to purchase the Notes to the extent the proceeds from any Disposition are used or committed to be used within 180 days to either (a) make any capital expenditure or (b) purchase any Replacement Assets. See "*Description of the Notes—Offers to Purchase—Dispositions*."

Excess Loss Offer.............................. Within 180 days after an Event of Loss with respect to the Projects occurs, the Issuer must (1) apply (or enter into a binding commitment within such 180-day period) the Net Available Amount received to rebuild, replace, repair or restore the Project (or affected portion thereof), and (2) provide to the Trustee within such 180-day period a Feasible Repair Certificate. See "*Description of the Notes—Offers to Purchase—Event of Loss*."

Ratings.. The Notes are expected to be rated at least "BB" by S&P, "Ba1" by Moody's and "BB+" by Fitch.

These ratings are not a recommendation to purchase, hold or sell Notes, and they do not comment as to market price or suitability for a particular investor. These ratings are based upon current information furnished to S&P, Moody's and Fitch by us and information obtained by S&P, Moody's and Fitch from other sources. These ratings may be changed, superseded or withdrawn as a result of changes in, or unavailability of, such information.

Collateral .... The Notes will be secured, subject to Permitted Liens, by the assets of the Issuer and Guarantors, *pari passu* and pro rata among all other Senior Secured Obligations. See "*Description of the Notes—Collateral*" and "*Description of the Notes—Accounts and Priority of Payments*."

Certain Covenants .... The Issuer and the Guarantors will agree to various limitations and restrictions, including (among other things), covenants prohibiting it from:

- creating, incurring, assuming or suffering to exist any Indebtedness or issue Disqualified Stock other than Permitted Indebtedness;
- creating, assuming, incurring or suffering to exist any Lien other than Permitted Liens;
- declaring or paying any dividend or making any other payment or distribution on its Equity Interests except subject to the Distribution Release Conditions;
- merge, consolidate, or sell, lease or dispose of their assets to another person other than certain enumerated exceptions; and
- enter into Affiliate Transactions, unless the terms of such Affiliate Transaction are no less favorable than would be obtained in a comparable arm's length transaction with a person who is not an Affiliate, subject to certain permitted exceptions.

The Indenture will also contain additional affirmative and negative covenants. The affirmative and negative covenants will be subject to a number of important qualifications and exceptions. See "*Description of the Notes*."

Listing .... An application will be made to list the Notes on the Singapore Exchange Trading Limited.

Transfer Restrictions .... The Notes are being offered only to (1) QIBs, in reliance on Rule 144A under the Securities Act and (2) non-U.S. persons outside the United States pursuant to Regulation S under the Securities Act. We have not registered the Notes under the Securities Act. The Notes are subject to restrictions on transfer and may only be offered in transactions exempt from or not subject to the registration requirements of the Securities Act. See "*Transfer Restrictions*."

Form of Notes, Clearing and Settlement .... Notes sold in reliance on Rule 144A will be represented by a global note in fully registered form deposited with the Trustee as custodian for, and registered in the name of, a nominee of DTC. Notes sold in offshore transactions in reliance on Regulation S under the Securities Act will be represented by a global note in fully registered form deposited with the Trustee as custodian for, and registered in the name of a nominee of, DTC.
Delivery of the Notes will be made in book-entry form only, through the facilities of DTC, on or about the date set forth on the cover page of this offering memorandum, against payment therefor in immediately available funds. See "*Form of Notes, Clearing and Settlement*."

Risk Factors .... You should carefully consider all of the information contained in this offering memorandum prior to investing in the Notes. In particular, we urge you to

	carefully consider the information set forth under "*Risk Factors*" for a discussion of risks and uncertainties relating to an investment in the Notes.
Governing Law	The Notes, the Note Guarantees, the Indenture, the Security and Depositary Agreement and certain other transaction documents will be governed by the laws of the State of New York. The other Security Documents will be governed by Chilean law. The Issuer and the Guarantors will consent to the jurisdiction of the U.S. Federal court of the Southern District of New York and any court of the State of New York sitting in New York County, New York City, and will agree that all disputes arising under the Indenture or any Note of the Note Guarantees may be submitted to the jurisdiction of such courts.
Trustee, Registrar, Offshore Collateral Agent, Paying Agent and Transfer Agent..................................	Citibank, N.A.
Onshore Collateral Agent	Banco de Chile.

SUMMARY OF FINANCIAL AND OTHER INFORMATION

The following summary financial and operating information should be read in conjunction with, and is qualified in its entirety by reference to, the Audited Consolidated Financial Statements and the Unaudited Consolidated Financial Statements and the information in the sections "Presentation of Certain Financial and Other Information," "Selected Financial Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" appearing elsewhere in this offering memorandum.

The Audited Consolidated Financial Statements have been audited by our current independent auditors, EY Chile. The report of EY Chile on such Audited Consolidated Financial Statements appear elsewhere in this offering memorandum.

The Consolidated Financial Statements have been prepared in accordance with IFRS. IFRS differs in certain respects from U.S. GAAP. We do not describe any differences between IFRS and U.S. GAAP in this offering memorandum. No reconciliation of any of our financial statements to U.S. GAAP has been prepared for this offering memorandum. Any such reconciliation could result in material quantitative differences. For further details and specific questions, investors should consult their professional advisors for an understanding of the differences between IFRS and U.S. GAAP.

Historical results are not necessarily indicative of future results.

Income Statement Data

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Profit or loss					
Revenue	15,617	20,920	72,887	62,516	52,097
Cost of sales	(14,918)	(16,637)	(55,477)	(50,540)	(44,644)
Gross profit (loss)	**699**	**4,283**	**17,410**	**11,976**	**7,453**
Administrative expenses	(458)	(430)	(2,836)	(2,287)	(2,416)
Operating profit	**241**	**3,853**	**14,574**	**9,689**	**5,037**
Finance income	0	15	16	216	219
Finance expenses	(6,263)	(6,425)	(25,279)	(25,730)	(25,504)
Foreign exchange differences	(415)	(789)	(82)	48	(171)
Impairment charges	-	-	-	(4,665)	-
Loss before taxes	**(6,437)**	**(3,346)**	**(10,771)**	**(20,442)**	**(20,419)**
Income tax benefit (expense)	1,693	(524)	1,182	1,312	5,515
Loss for the period	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:					
Owners of the Parent	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Non-controlling interests	-	-	-	-	-
Other comprehensive income (loss)	-	-	-	-	-
Total comprehensive loss for the period, net of tax	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:					
Owners of the Parent	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Non-controlling interests	-	-	-	-	-

Balance Sheet Data

	As of March 31,		As of December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Assets					
Current assets					
Cash and cash equivalents	2,639	7,692	7,363	18,428	13,313
Other financial assets	-	-	-	-	3,527
Trade and other current receivables	7,188	12,113	10,565	11,836	13,623
Accounts receivable from related entities	3,728	3,224	3,836	3,643	-
Inventory	93	-	63	-	-
Total current assets	**13,648**	**23,029**	**21,827**	**33,907**	**30,463**
Non-current assets					
Trade and other current receivables, non-current	12,063	6,299	11,742	1,245	-
Other non-current non-financial assets	-	-	-	-	258
Intangible assets other than goodwill	489	497	491	499	507
Goodwill	-	-	-	-	4,665
Property, plant and equipment	389,975	411,020	395,264	416,757	427,308
Deferred tax assets	37,791	34,393	36,098	36,149	33,604
Total non-current assets	**440,318**	**452,209**	**443,595**	**454,650**	**466,342**
Total assets	**453,966**	**475,238**	**465,422**	**488,557**	**496,805**
Equity and liabilities					
Current liabilities					
Other current financial liabilities	12,175	10,011	16,404	13,983	11,370
Trade and other payables	13,877	12,816	10,288	11,805	11,689
Accounts payable to related entities	4,889	4,600	4,902	4,724	744
Lease liabilities	362	362	362	343	-
Other non-financial liabilities	-	-		698	533
Total current liabilities	**31,303**	**27,789**	**31,956**	**30,855**	**24,336**
Non-current liabilities					
Other non-current financial liabilities	372,501	384,673	378,811	389,933	396,675
Provisions	53,226	51,892	52,885	51,615	50,258
Lease liabilities	11,562	11,847	11,652	12,014	-
Deferred tax liabilities	-	-	-	1,233	-
Accounts payable to related entities	-	-		-	3,499
Total non- current liabilities	**437,289**	**448,412**	**443,348**	**454,795**	**450,432**
Total liabilities	**468,592**	**476,201**	**475,304**	**485,650**	**474,768**
Equity					
Paid-in capital	89,801	93,001	89,801	93,001	93,001
Retained earnings (accumulated losses)	(99,683)	(90,094)	(90,094)	(70,964)	(70,964)
Result for the period	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Equity attributable to the owners of the Parent	(14,626)	(963)	**(9,882)**	**2,907**	**22,037**
Non-controlling interests	-	-	-	-	-
Total equity	**(14,626)**	**(963)**	**(9,882)**	**2,907**	**22,037**
Total equity and liabilities	**453,966**	**475,238**	**465,422**	**488,557**	**496,805**

Consolidated Statements of Cash Flows

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Cash flows from operating activities					
Loss before taxes	**(6,437)**	**(3,346)**	**(10,771)**	**(20,442)**	**(20,419)**
Adjustments to reconcile profit/loss to net cash flow:					
Depreciation	5,330	5,754	21,383	23,138	22,545
Foreign exchange differences	415	789	82	(48)	171
Finance expenses	6,263	6,425	25,279	25,730	25,504
Impairment charges	-	-	-	4,665	-
Changes in assets and liabilities					
Inventory	(30)	-	(63)	-	-
Trade and other account receivables	3,056	(5,825)	(9,226)	1,787	(1,504)
Other current assets	-	(66)	19	-	-
Trade payables and other current liabilities	3,589	1,093	(1,517)	(983)	3,699
Other non-financial assets and liabilities	(463)	(193)	(19)	(1,499)	147
Account receivable and payable with related entities	95	-	(14)	(2,519)	-
Other movements	-	-	-	-	102
Interest paid	(10,727)	(11,008)	(22,234)	(21,954)	(22,042)
Net cash flow generated by (used in) operating activities	**1,091**	**(6,377)**	**2,919**	**7,875**	**8,203**
Cash flows from investment activities					
Acquisition of property, plant, equipment and intangibles	-	(14)	(74)	(88)	(930)
Proceeds from short-term investments, net	-	-	-	3,526	(3,526)
Net cash flow generated by (used in) investing activities	**-**	**(14)**	**(74)**	**3,438**	**(4,456)**
Cash flows from financing activities					
Reduction of capital	-	-	(3,200)	-	(24,603)
Payment of principal portion of lease liabilities	(90)	(86)	(343)	(327)	-
Repayment of borrowings	(5,725)	(4,259)	(10,367)	(5,871)	(801)
Net cash flow used in financing activities	**(5,815)**	**(4,345)**	**(13,910)**	**(6,198)**	**(25,404)**
Effect of changes in exchange rates on cash and cash equivalents	-	-	-	-	-
Net increase (decrease) in cash and cash equivalents	**(4,724)**	**(10,736)**	**(11,065)**	**5,115**	**(21,657)**
Opening balance of cash and cash equivalents	**7,363**	**18,428**	**18,428**	**13,313**	**34,970**
Closing balance of cash and cash equivalents	**2,639**	**7,692**	**7,363**	**18,428**	**13,313**

Alternative performance measures

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Alternative performance measures					
Adjusted EBITDA[1]	5,571	9,607	36,887	33,741	28,509
Reconciliation of Adjusted EBITDA to Gain (Loss)					
Loss	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Income tax (benefit) expense	(1,693)	524	(1,182)	(1,312)	(5,515)
Foreign exchange differences	415	789	82	(48)	171
Finance expense	6,263	6,425	25,279	25,730	25,504
Interests withholding tax	-	-	930	914	918
Finance income	-	(15)	(16)	(216)	(219)
Impairment charges	-	-	-	4,665	-
Depreciation and amortization	5,330	5,754	21,383	23,138	22,554
Adjusted EBITDA	**5,571**	**9,607**	**36,887**	**33,741**	**28.509**

(1) We define "*Adjusted EBITDA*" as gain (loss) after adding back (to the extent the number is negative) or subtracting (to the extent the number is positive), as the case may be, (1) income tax benefit (expense), (2) foreign exchange differences, (3) finance expense, (4) finance income, (5) interests withholding tax, (6) impairment charges, and (7) depreciation and amortization. Adjusted EBITDA is not an IFRS measure but we consider it useful for investors as it presents a measure of our operational economic performance from management's perspective.

	As of March 31,		As of December 31,		
	2021	2020	2020	2019	2018
Operating Data					
Total installed capacity (MW)	**239.2**	**239.2**	**239.2**	**239.2**	**230.8**
Energy sales (GWh)					
PPA sales – Contracted Customers	133.7	192.8	609.9	532.9	359.9
Spot market sales	25.7	-	26.2	163.3	274.8
Total energy sales	**159.1**	**192.8**	**636.1**	**696.3**	**634.6**
Generation (GWh)					
Wind	135.1	113.4	671.8	700.0	722.1
Minus own consumption, maintance and losses	4.0	1.5	54.5	12.8	14.7
Curtailment	1.7	3.6	16.2	25.9	72.8
Net generation	**129.4**	**108.3**	**601.1**	**661.3**	**634.6**
Contracted Energy	30.0	30.0	35.0	35.0	0
Total energy available for sale before transmission	**159.1**	**138.3**	**636.1**	**696.3**	**634.6**
Purchases spot market	-	54.5	-	-	-
Total energy sales	**159.1**	**192.8**	**636.1**	**696.3**	**634.6**

RISK FACTORS

Prospective purchasers should carefully consider all of the information set forth in this offering memorandum and, in particular, the following risk factors. This section does not describe all risks applicable to the Notes. Additional risks not presently known or that may currently be deemed immaterial may also adversely affect the Notes or an investment in the Notes.

Our business is subject to various changing economic, political, social and competitive conditions. Any of the following risks, if they actually occur, could materially and adversely affect our business, results of operations and financial condition and, as a result, our ability to fulfill our obligations under the Notes. An investment in the Notes involves risk. Therefore, you could lose a substantial portion or all of your investment in the Notes. You should consider carefully all the information contained in this offering memorandum, including the risk factors set forth below, before deciding to invest in the Notes. You should note that the risks described below are not the only risks to which we are exposed. There may be other risks that are not presently known to us or that we do not presently consider to be material that could adversely affect our ability to fulfill our obligations under the Notes.

Risks Related to Our Business

We are dependent on our counterparties to generate substantially all of our revenues.

We are dependent on our counterparties to generate substantially all of our revenue and our financial results are dependent upon counterparties under PPAs fulfilling their contractual obligations. The majority of our PPAs are under "take and pay" terms, and not subject to a minimum amount of energy purchase for the relevant period. As of the date of this offering memorandum, we are a party to 108 PPAs with 41 separate counterparties with a weighted average term of 10.6 years. For the fiscal year 2021, we estimate that 623.63 GW/h of our total generation capacity (at P50) will be contracted, representing 98.44% of the estimated total generation for the period. Revenues derived from these long-term agreements constitute our main source of revenue and are expected to continue to constitute most of our revenue until 2031. Accordingly, we are dependent on our counterparties' continued willingness and ability to timely meet their respective contractual obligations with us.

In addition, we rely on a limited number of Contracted Customers to purchase a significant portion of our output. On average, for the fiscal years ending December 31, 2020, 2019 and 2018, revenues associated with our three largest Contracted Customers (Enel, CGE and Metro), represented in aggregate 70.2% of our total sales. A loss of one of our main Contracted Customers may be difficult or impossible to replace. Likewise, further concentration of counterparties would increase our dependence on any one counterparty. The failure of any material counterparty to perform its contractual obligations or make required payments may negatively impact our results of operations.

We depend on wind conditions and other factors beyond our control to generate electricity.

Electricity generated from wind energy depends heavily on suitable wind conditions, wind speeds and other conditions at the relevant site. Objects such as buildings, trees or other wind turbines near our wind farms, especially in more built-up areas may reduce our wind resources due to the disruption of wind flows, known as "wake effects." Other existing or future projects, when developed, would have a negative wake effect on our Projects. We cannot assure you that owners of land near our Project sites will not lease or transfer their land use rights to other developers who may construct wind turbines or other structures that would have negative wake effects. Such developments may reduce the operational performance of our wind farms, which could have a material adverse effect on our business, financial condition or results of operations.

Furthermore, we may be affected by certain other factors, such as severe weather and other factors beyond our control. If such conditions are unfavorable or below our expectations, our Projects' electricity generation and the revenue generated from our Projects may be substantially below our expectations. Operation and maintenance problems at Projects, including as a result of natural events, may cause our electricity generation to fall below our expectations. Adverse conditions caused by one or more of these factors beyond our control could adversely affect our business, financial condition, results of operations and cash flows.

Oversupply conditions may affect our profitability and results of operations.

In the context of the tender process, the CNE develops demand projections for the procurement of supply for Regulated Customers, based on each DisCos' projected requirements. See "*Legal and Regulatory Framework—Tender Process*." To reduce the risks and uncertainty associated with demand projections, the forecasts are updated annually. Because these demand projections are based upon assumptions that may prove to be inaccurate, actual energy demand from Regulated Customers may deviate substantially from the forecasts used in the procurement of the PPAs. In the case that actual demand is below the contracted energy at a particular time (that is, the DisCos are over-contracted), the actual demand will be covered by all generators in proportion to their contracted energy. Therefore, the oversupply risk is distributed evenly (pro rata) across the generation market.

DisCos generate revenue by selling power to Regulated Customers at an officially determined tariff that is composed of three main components: (i) generation prices, (ii) transmission tolls, and (iii) the value added in distribution ("*VAD*"). See "*Industry—Business Segments—Distribution Segments*." The generation component of the tariff to Regulated Customers is based on the price paid by the DisCos to generators for supply under their PPAs. The transmission component is also a pass-through cost based on the tolls incurred by DisCos transmitting power, which are collected by the DisCos, and paid to the respective transmission companies.

However, unlike the generation and transmission components, the VAD represents an actual income to the DisCos and is calculated based on the average annualized distribution cost of an efficient (model) company under specified demand and supply conditions. See "*Industry—Business Segments—Distribution Segments—Compensation*." In simplest terms, it is calculated as the ratio between the total distribution costs and projected demand. Thus, if the demand projection used in determining a DisCo's VAD overstates actual demand, then the VAD will underestimate the DisCo's actual distribution costs, leading to revenue under-collection and lower margins. This risk of under-collection creates a strong incentive for DisCos to avoid overestimating their demand. Due to the fact that this VAD component is independent of the actual costs of the DisCos, it incentivizes the DisCos to cut costs and project supply as close to reality as possible in order to meet the "model" company. The VAD therefore serves as an oversupply risk mitigant for the Chilean auction system.

A number of additional factors have also been implemented to mitigate the risk of DisCos over-contracting generation and subsequently apportioning PPA contracts down. Should the DisCos incorrectly project demand using inaccurate information in the process, the Superintendency of Electricity and Fuels has the authority to penalize the DisCos. Depending on the severity of the infraction, penalties could range from a monetary charge between US$830 and US$8.3 million, to closure and even to license cancellation.

Our revenues are affected by the supply and oversupply levels projected by the CNE within the context of each auction process for the determination of energy prices in Chile. Likewise, some of the projections that appear in this offering memorandum directly correlate to such projections made by the CNE. Such projections may be based on assumptions that may be erroneous or inaccurate, or may be subject to other factors that are beyond our control. In addition, change of circumstances in the Chilean energy market may make such projections erroneous, such as changes in consumption patterns or the level of efficiency in the production of energy by generating companies.

The COVID-19 pandemic has created oversupply conditions in the energy generation industry as a result of many production and industry activities being suspended, postponed or reduced. Currently, the regulated contracted energy is higher than the regulated consumed energy due to the regulated demand rate growth below the level projected by CNE for the auction processes. According to the information contained in the Preliminary CNE's report dated April 2021, the calculated oversupply level in 2020 was 38.7%, with oversupply progressively decreasing by 2025. Consequently, the CNE modified the 2019/01 regulated auction process in order to move the supply start year from 2024 to 2026, and modified the schedule of the auction and the contracted energy level in a new process named 2021/01.

These and other factors may affect our profitability and results of operations, and consequently, our ability to pay our obligations under the Notes.

Our PPAs are subject to certain termination, renewal or rollover risks.

We mitigate our oversupply exposure by entering into short-term PPAs with Unregulated Customers. Power sold under these PPAs with Unregulated Customers have various expiration dates between 2023 and 2033. For the three-month period ending March 31, 2021, 86.9% of our revenue derived from sales of energy from PPAs, and over the fiscal years ended December 31, 2020, 2019 and 2018, 94.1%, 92.8% and 83.8% of our revenue derived from sales of energy from PPAs, respectively. In addition, these PPAs are subject to termination prior to expiration in certain circumstances, including, in the case of PPAs with DisCos downgrade of our credit rating (BB+ local scale). When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, the price received under subsequent arrangements may be reduced significantly, and/or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA. In addition, if we are not able to secure a new PPA on acceptable terms, we may be forced to sell energy in the spot market, which may make our projected revenues difficult to predict. Furthermore, our projections do not consider the renewal or rollover of existing PPAs, or the entering into new PPAs on terms at least similar to those PPAs currently in effect. We cannot guarantee that PPAs will be executed after the expiration of our current PPAs or that the terms of new PPAs, if any, will be similar to our existing PPAs. Each of these situations, alone or in the aggregate, could negatively affect our results of operations and our ability to make payments under the Notes.

The enactment of the Tariff Stabilization Law will temporarily affect our revenues.

As a result of the social unrest that began in Chile in October 2019, the Tariff Stabilization Law was enacted in November 2019 to temporarily stabilize electricity prices for Regulated Customers, by rescinding a recent increase in electricity tariffs payable by Regulated Customers and effectively preventing us from collecting revenues at the levels set forth in our existing PPAs. See "*Legal and Regulatory Framework—Tariff Stabilization Framework*." While the Tariff Stabilization Law will create a mechanism to record and recover any differences between PPA prices and stabilized prices under the Tariff Stabilization Framework via PEC Receivables, in the short term, we expect our revenues to decrease, at a minimum, by the amount corresponding to the difference between our PPA prices and the PEC determined under the Tariff Stabilization Framework. The Tariff Stabilization Framework, or other future legal or regulatory intervention in the determination of energy prices in the Chilean market, could cause us to have a cash flow shortfall, negatively affecting our results of operations and our ability to make payments under the Notes. See "*—Risks Related to the PEC Receivables*" below for a more detailed description of risks associated with the recording, collection and enforcement of PEC Receivables.

Prices of PPAs determined as a result of recent auction processes have had lower rates than those PPAs we currently have in effect.

In Chile prices under PPAs between DisCos and generation companies are set through a public tender process, subject to certain adjustments. PPA prices are expected to decrease as a result of the expected introduction of renewable generation assets and other more efficient technologies into the Chilean electricity generation matrix. PPAs that become effective in 2019, 2020 and 2021 have already been awarded at lower prices than those from our existing PPAs, and prices in subsequent PPA auctions are expected to continue to decline given the increase in competition due to additional power generation sources.

This decline in PPA prices is expected to translate into a PNP below the Adjusted PEC, resulting in the generation of surpluses which will support PEC Receivables repayment. In addition to these dynamics, the CNE is obligated to adjust the PEC for the Tariff Periods between January 1, 2025 and December 31, 2027 so that sufficient surpluses are generated to repay the PEC Receivables in full by the latter date.

Subsequent PPAs may not be available at prices comparable to those set forth in our existing PPAs, in case one of our existing PPAs is terminated. The early termination of one of our existing PPAs could affect our profitability and our results of operations. If this occurs, we would have to further rely on the spot market to maintain profitability, which prices are difficult to predict. If we are unable to maintain our profitability, we could temporarily or permanently cease operations of our Projects, which could have a material adverse effect on our financial results.

We may experience a downward pressure in the price of energy we sell.

As new participants have entered the SEN and existing generators expand their renewable generation capacity, we could continue to experience downward pricing pressure, including pressure from our customers to renegotiate our PPAs or political pressure to force the government to change the terms and conditions of existing PPAs with DisCos to supply Regulated Customers. PPAs that become effective in 2019, 2020 and 2021 have already been awarded at lower prices (when compared to those awarded in 2017 or earlier), and prices in subsequent PPA auctions are expected to continue to decline given the increase in competition due to additional power generation sources. Consequently, in the long term, we expect that a majority of our sales of energy will derive from the spot market upon the expiration of our PPAs with DisCos between 2031 and 2033 in the event we are not able to enter into new PPAs in terms and with prices substantially similar to our existing PPAs or economically beneficial to us.

Spot market sales represented 13.1% of our total revenue for three-month period ending March 31, 2021 and 5.9% of our total revenue for the fiscal year ending December 31, 2020. Our revenues derived from the spot market are partially dependent on the actions of third parties and factors beyond our control.

Our revenues derived from the spot market depend, in part, on factors beyond our control.

Generators like us receive merchant spot market revenue as a result of the net value of energy injected (supplied) into the system less the energy withdrawn (demanded) into the system. The following factors, most of which are beyond our control, may unfavorably impact our revenues in the spot market:

- adverse general economic conditions, political instability or social unrest in Chile;
- an increase or decrease in marginal production costs of generators in the Chilean market;
- a deterioration of our financial condition and profitability;
- changes in policy, regulation and actions and interpretations of regulatory bodies;
- unforeseeable changes in weather conditions and phenomena, or natural disasters, such as earthquakes;
- health epidemics or pandemics or other contagious outbreaks, such as the recent COVID-19 outbreak;
- fluctuations in energy prices caused by regional, domestic and international supply and demand;
- changes in availability and demand of electricity in Chile;
- increases in capital costs;
- increases in local and national taxes resulting from changes in tax regulations or the interpretation thereof;
- opposition to energy infrastructure development, particularly in environmentally and socially sensitive areas or in areas inhabited by indigenous populations;
- availability and competitiveness of alternative energy sources or more efficient power plants;
- difficulties obtaining the necessary rights or permits for national transmission system expansion or major maintenance projects;

- availability of spare parts or the ability of our O&M provider to fix or replace malfunctioning parts on a timely basis or at all;
- early termination of significant contracts for which renewal does not depend on us; and
- the ability of our service providers to comply with their contractual obligations.

These and other factors could materially and adversely affect our energy generation, cash flows, financial condition and results of operations, as well as our ability to make interest payments on the Notes.

We may not be able to refinance the Notes.

We may need to raise a significant amount of debt or equity capital in order to repay our outstanding obligations under the Notes in the event we do not generate sufficient Available Cash (as defined under "*Description of the Notes*") necessary to pay all amounts corresponding to the Target Debt Balance (as defined under "*Description of the Notes*"). While failure to pay the Target Debt Balance does not constitute a Default or Event of Default under the Indenture, failure to pay these amounts will increase the outstanding amount of principal payable at maturity.

If we are unable to raise sufficient debt or equity capital to repay all outstanding obligations under the Notes at maturity and we are otherwise unable to extend the maturity dates or refinance these obligations, we would be in default, which would have a material adverse effect on our financial condition and ability to continue as a going concern.

We may not be able to repurchase the Notes upon the occurrence of a Change of Control.

Upon the occurrence of a Change of Control (as defined in "*Description of the Notes*"), we may be required by the holders of the Notes to offer to repurchase all of the outstanding notes at 101% of their principal amount, plus accrued and unpaid interest to, but excluding, the date of purchase. The source of funds for any such purchase of the Notes will be our available cash or cash generated from our operations or other sources, including borrowings, sales of assets or sales of equity. We may not be able to repurchase the notes upon a Change of Control because we may not have sufficient financial resources to purchase all of the Notes that are tendered upon a Change of Control. Our failure to repurchase the notes upon a Change of Control would cause a default under the Indenture governing the Notes.

Our business is dependent on overall macro-economic conditions of Chile.

General economic conditions of Chile may affect our activities. Certain general macro-economic risks include currency exchange rates, interest rates, inflation rates, industry conditions, political and diplomatic events and trends, health concerns, including the COVID-19 outbreak, and general levels of economic activity. The profitability of a significant portion of revenue-generating activities depends, to a great extent, on correct assessments of the future course of price movements in energy prices and other factors that are beyond our control or that we may not be able to preemptively identify. Negative macro-economic conditions may negatively affect our results of operations and our revenues.

The coronavirus outbreak could have an adverse effect on our business.

The spread of the coronavirus (COVID-19) has caused severe disruptions in the world economy, including the demand for energy, the movement of people and services and the visibility into future conditions, which could in turn disrupt our business and operations. The virus has spread rapidly across the globe, including Chile. The continued spread and related government restrictions put in place to slow it, including the imposition of quarantines and medical screenings, travel restrictions and the suspension of certain activities, have already affected, and may continue to affect our supply chain as well as our customer base. While the significance of the long-term impact on us is still uncertain, a material adverse effect on our customers, counterparties, or service providers could significantly impact our operating results. The unprecedented nature of the current pandemic and market conditions could materially adversely affect our near-term and long-term revenues, earnings, liquidity and cash flows, and has required significant actions in response, including but not limited to, telework (work from home) requirements for administrative employees, voluntary or mandatory vaccination programs, employee furloughs, reduction of on-site personnel, postponement of programmed non-critical maintenance, increase in monitoring of health and safety across operators, task force of specialized professionals hired to design new plant work-flows and employee single-person isolation measures, initiatives to support local communities in the surrounding areas of our Projects, emergency procedures in response to positive cases, extended collection periods with some of our customers, expense reductions, partial plant and operational shutdowns, all in an effort to mitigate such impacts.

The extent of the impact of the pandemic on our business and financial results will depend largely on future developments, including the duration of the spread of the outbreak, the impact on capital and financial markets and the related impact on consumer confidence and spending, all of which are highly uncertain and cannot be accurately predicted based on the impacts observed to date. This situation is changing rapidly, and additional impacts may arise that we are not aware of currently. To the extent the COVID-19 pandemic continues for a longer period than expected and due to the uncertainty surrounding the effects of the outbreak in the economy and governments and regulators take additional measures to address the negative impacts of the pandemic, we may require funds in addition to those referred to above to satisfy incremental working capital or liquidity needs (including as a result of the credit deterioration of our counterparties). Also, the additional preventive measures adopted by our management team might not be sufficient to address the negative impacts of the COVID-19 pandemic and government bodies and regulatory agencies might take additional mitigating measures or policies that could impact our business and operations. As such, there is no assurance that the COVID-19 pandemic will not have an adverse effect on our business, financial condition and results of operations.

Payments on the Notes are dependent solely on the cash flows generated by our Projects. Failure to generate energy or to perform our obligations will result in reduced revenue and could materially and adversely affect our results of operations and ability to make payments on the Notes.

We are dependent upon the cash flows produced from our Projects, and therefore dependent upon successfully operating our Projects and selling electricity at prices sufficient to continue operations and to meet our financial and debt payment obligations. Failure to generate electricity or to provide capacity, breach of obligations under the PPAs, or non-compliance with applicable rules and regulations that may result in sanctions or cancellations of permits by the relevant governmental agencies, may have a material adverse effect on our cash flow, financial condition and results of operations, and could impair our ability to make debt service payments under the Notes.

Energy generation activities carry inherent operating hazards.

We anticipate our activities will involve a number of operating hazards related to the generation of electricity, including hazards related to operating large pieces of rotating equipment, structural collapse, machinery failure, and delivering electricity to transmission and distribution systems. In addition, we are exposed to natural disaster risks and other hazards such as fire and explosions. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, disruption of communication systems and technology, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being subject to various litigation matters, including regulatory and administrative proceedings, asserting claims for substantial damages, may result in us being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to regularly improve environmental, health and safety performance, but there can be no guarantee that such programs will fully and effectively eliminate the inherent risk of environmental, health and safety liabilities related to our operations.

Our employees and other third parties may be in close proximity with, among other things, large pieces of mechanized equipment, moving vehicles, manufacturing or industrial processes, and regulated materials. If we fail to design and implement adequate practices and procedures, if the practices and procedures we implement are ineffective or if our service providers or other suppliers do not follow them, such persons may become injured and our and others' property may become damaged. Unsafe work sites also have the potential to increase employee turnover or raise our operating costs. Any of the foregoing could result in financial losses, which could have a material adverse effect on our financial results.

Inadequate operating systems and procedures may increase operating costs and the potential incidence of operator error; equipment failure could have a detrimental effect on our operations.

The ability of our plants to meet availability requirements and generate the required amount of power to be sold to counterparties may be detrimental to the revenues we receive. There is a risk of equipment failure due to wear and tear, more frequent or larger than forecasted downtimes for equipment maintenance and repair, unexpected construction delays, latent defect, design error, operator error or force majeure events, among other things, any of which could adversely affect our financial results. Additionally, older equipment, even if maintained in accordance with good practices, is subject to operational failure, including events that are beyond our control, and may require unplanned expenditures to operate efficiently. Unplanned outages of generation facilities, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase operation and maintenance expenses and may reduce our revenues or require us to incur additional costs, sometimes, in excess of the price we receive under the PPAs as a result of our necessity to purchase power from other generators on the spot market to fulfill our contractual obligations. We cannot guarantee that any or all of our power generation equipment will not malfunction or otherwise be unavailable to generate electricity for an extended period of time. Any such extended malfunction or unavailability would have an adverse effect on our results of operations.

Our Projects are dependent on interconnection and transmission infrastructure.

Our Projects are connected to the main Chilean grid, the SEN. We provide energy to our customers utilizing existing transmission lines that by law have an open access policy. Consequently, we rely on services provided by third parties such as Transelec, who own or control the transmission lines and substations we use to provide energy. A failure or delay in the operation or development of these interconnection or transmission facilities or a significant increase in the cost of the development of such facilities that may result in a delay in scheduled works could limit the amount of power we may deliver resulting in loss of revenues. In the event there are transmission restrictions, due to technical, design or other conditions, or there are delays in maintenance or repair of existing transmission systems or the installation of new transmission systems, our ability to supply energy to our counterparties could be limited, and this could materially affect our business, results of operations and financial condition.

If the electric transmission infrastructure is inadequate, the recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have a sufficient incentive to invest in expansion of transmission infrastructure. Additionally, we cannot predict whether interconnection and transmission facilities will be expanded to accommodate the delivery of electricity by our Projects. Likewise, the generation of electricity may be curtailed without compensation due to transmission limitations or limitations on the electricity grid's ability to deliver power generated by us, reducing our revenues and impairing our ability to capitalize fully on a particular generating potential. Such curtailments could have a material adverse effect on our financial results.

We may be exposed to risks related to litigation, arbitration and administrative proceedings that could materially and adversely affect our business and financial performance in the event of an unfavorable ruling.

Our business may expose us to litigation relating to labor, regulatory, environmental advocacy or community complaints, tax and administrative proceedings, governmental investigations, tort claims, contract disputes and criminal prosecution, among other matters including proceedings in which our owners and directors are or may be involved. In the context of these proceedings, we may not only be required to pay fines or money damages but also be subject to sanctions, revocation of our permits or injunctions affecting our ability to continue our operations. While we may contest these matters vigorously and make insurance claims when appropriate, litigation and other proceedings are inherently costly and unpredictable, making it difficult to accurately estimate the outcome of actual or potential litigation, arbitration or proceedings. Although we may establish provisions as we deem necessary, the amounts that we reserve could vary significantly from any amounts we actually pay due to the inherent uncertainties in the estimation process. Any such litigation, dispute, administrative proceedings or investigations could result in a substantial cost and diversion of management efforts, which could independently have a material adverse effect on our financial condition and operating results.

We engage in transactions with related parties and such transactions present possible conflicts of interest that could have an adverse effect on us.

We have entered into transactions with related parties. Related party transactions create the possibility of conflicts of interest. Such a conflict could cause an affiliate to seek to advance its economic interest above ours. In addition, other related parties may from time to time provide services to us if and as approved by the Board of Directors. It is possible that we could obtain such goods and services from unrelated persons at a lesser price and that a conflict of interest could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We may be unable to hire and retain qualified key employees.

The success of our business will depend, in part, on our ability to retain, recruit and motivate key employees who have experience in our industry. Experienced employees in the power industry are in high demand and competition for their talents can be intense and we may not succeed in attracting, integrating or retaining personnel with the experience or at the compensation levels necessary to preserve our business quality and reputation, or to support or expand our operations. The loss of any experienced officer, key employee, senior manager or member of the management team could adversely affect our ability to implement our business strategy. Further, an aging work force in the power industry may necessitate recruiting, retaining and developing the next generation of leadership. A failure to attract and retain executives and other key employees with specialized knowledge in power generation could have an adverse impact on our financial results because of the difficulty of promptly finding qualified replacements.

Our Projects may impact the lifestyle and conditions of local communities.

Historically, power generation projects are subject to high levels of scrutiny by political parties, environmental groups and other organized advocacy groups, and local residents. The perception that a local community's lifestyle may be endangered by the development, construction and operation of a Project, may trigger protests, political action, legal remedies or negative press that may threaten the long-term viability of a Project or disrupt the normal operations.

While we believe our operations incorporate the best industry practices in connection with social responsibility, in order to minimize any negative impact in all communities in which we operate, delays or disruptions may be caused by organized efforts from these groups that may deviate resources and attention, and ultimately affect our revenues.

Compliance with environmental regulations may require significant expenditures that could adversely affect our results of operations.

Our operations are regulated by a wide range of environmental requirements in Chile. Failure to comply with environmental requirements can result in civil, administrative or criminal fines or sanctions, claims for environmental damages, remediation obligations, the revocation of environmental authorizations or the temporary or permanent closure of facilities.

Chilean environmental regulations have become increasingly stringent in recent years, as well as the enforcement of existing legal and permit requirements, and this trend is likely to continue in the near future. New environmental requirements or changes in the application, interpretation or enforcement of existing requirements, could result in substantially increased capital, operating or compliance costs, and could impose conditions that restrict or limit our operations. In addition, changes to environmental regulations could create additional conditions to our operations, could adversely affect our revenues, and thus could have an adverse effect on our financial condition and results of operations.

Regulatory authorities may impose fines on us as a result of energy supply failures.

We may be subject to regulatory fines in Chile for breach of current regulations, including the system experiencing a blackout and/or a delay in reestablishing energy after a blackout. All electricity companies may be subject to these fines if a system blackout results from any generator's or the transmission system operator's operational mistake, including failures related to the coordination of duties of system participants. A power generation company may also be obligated to make compensatory payments to Regulated Customers affected by electricity shortages or to Unregulated Customers.

The Ministry of Energy may dictate a rationing decree when an electricity system is facing or is expected to face a generation deficit as a consequence of prolonged breakdown of generating units, or as a consequence of a drought or as a result of unusually high demand. If a rationing decree is enacted, fines may be imposed on power generation companies that do not comply with the measures ordered in the decree. Any such fines may have a material adverse effect on our business, results of operations or financial condition.

We and the grid itself are subject to the risk of mechanical or electrical failures and any resulting unavailability may affect our ability to fulfill our contractual commitments and/or make us liable for fines by the Superintendency of Electricity, and thus adversely affect our financial performance.

Although we perform regular maintenance and operational enhancements to maintain the commercial availability of our Projects, the grid itself is at risk of mechanical or electrical failure and may experience periods of unavailability. Any unplanned unavailability of our Projects may adversely affect our financial performance as we may need to buy electricity on the spot market at a higher price than the price we receive under our PPAs in order to fulfill our obligations with our counterparties. Under our PPAs, we have also guaranteed certain efficiency parameters to our counterparties, which could be adversely affected during any periods of commercial unavailability.

There is no assurance that our insurance policies, which cover losses related to earthquakes and business interruptions, among others, would be sufficient or adequate in the event of a loss of our insured facilities.

We maintain comprehensive insurance with respect to our facilities, including general liability insurance and other insurance policies customary in the power industry, which cover losses related to earthquakes, property damages and business interruptions, among others. Such insurance coverage may not be available in the future at commercially reasonable costs or the amounts for which we are insured or amounts which we will receive under such insurance coverage may not cover all of our losses. In the event there is a total or significant loss at our facilities, the proceeds received in respect thereof may not be sufficient to satisfy our obligations under the Notes.

Our business may require substantial capital expenditures for ongoing maintenance and environmental requirements.

Ongoing maintenance and improving the capabilities of our Projects may require incremental capital expenditures in the future. Furthermore, over time we may need to invest significant capital to modernize our existing facilities in order to comply with any new standards and other regulatory requirements. If we are unable to finance any such capital expenditures, or if we are required to use funds for such capital expenditures that would otherwise have been used to grow our business, our business could be adversely affected.

The performance and management of the O&M Agreements with Vestas may adversely affect our business, financial position and results of operations.

Under the O&M Agreements, Vestas is responsible for the operation and maintenance for the Projects. Any failure to perform such operation and maintenance activities could disrupt our operations and adversely affect our business, financial position and results of operations.

Lawsuits against us could adversely affect our results of financial condition or operations.

In the ordinary course of our business, we enter into agreements with counterparties in connection with the sale of electricity under our PPAs. The interpretation and enforcement of certain provisions of our existing or any additional agreements may result in disputes among us, our counterparties or third parties and we cannot assure you that any claims, suits or other legal proceedings arising from such agreements against us will not adversely affect our results of financial condition or operations.

The Chilean Government's heightened requirements regarding the use of NCREs may lead to increased competition and increased volatility in spot prices.

As the Chilean government heightens its requirements regarding the use of NCREs, we expect new participants in the renewable energy sector to enter the market. The current regulatory framework targets a 20% NCRE power generation requirement by 2025, which has already been met. If new participants enter, we could experience downward pricing pressure, including pressure from our Unregulated Customer counterparties to renegotiate our PPAs, which could have a material adverse effect on our profit margins, thereby adversely affecting our business, financial condition and results of operations. In addition, NCREs are likely to lead to very low spot prices at certain times of the day, and very high prices at other times, particularly at night. This may create instability in prices in the spot market and may have a negative impact on our financial condition and results of operations.

We operate in a highly regulated environment; any changes in laws or changes in the interpretation of existing laws may negatively impact our business, financial condition and results of operations.

Chile's electricity sector has a regulatory framework that has been in effect and has evolved significantly over more than three decades. This has enabled the development of an industry with a high level of participation of private capital to drive the industry's development. See "*Industry Overview*." The electricity sector and its private participants are subject to various regulations and the supervision of various technical bodies. The material laws and regulations covering the Chilean electricity sector are contained in the Electricity Law, the Transmission Law and the Environmental Law. See "*Legal and Regulatory Framework*."

New laws and regulations, changes to existing legislation and new interpretations of existing laws or regulations, together with their political and social considerations, are beyond our control. The outcome of any of these events alone or taken together may be difficult to predict, and if they impose onerous obligations or requirements to our business or our operations, such events may result in a decrease in our revenues.

For example, Law 21,249, enacted on August 8, 2020 (and subsequently modified on January 5, 2021), established that DisCos may not suspend the service to final clients for lack of payment, under certain circumstances and upon meeting certain requirements, and such affected clients shall pay all outstanding amounts to DisCos in installments. Likewise, power generation companies must continue to provide their services to DisCos, and DisCos may also pay any due and unpaid amounts in installments to power generation companies, in the same proportion as such payments made by final clients, without penalties, interest or any other expenses.

Additionally, as of the date of this offering memorandum, the Chilean Congress was discussing a bill that would amend the Electricity Law to incorporate a new entity into the electricity distribution system in Chile to promote competition. This entity would be a private enterprise which, like generation companies and DisCos, would be subject to the oversight of the CNE and the National Electrical Coordinator. As currently envisioned, a trader would be able to purchase blocks of energy from generation companies and sell sub-blocks of energy to Regulated Customers at prices comparatively lower than those offered by DisCos. Currently, only generation companies are allowed to sell electricity to DisCos and end consumers. Based on the current status of the legislative discussion, this new entity and its activities is not expected to reduce the amount of electricity that awarded generation companies currently supply to DisCos. Current status of legislative discussion suggests that the energy blocks such trader would be permitted to trade will be either related to (i) incremental demand of Regulated Customers not being supplied by awarded generation companies or (ii) energy blocks being released by awarded generation companies as a result of the termination of their PPAs.

We are subject to a number of laws, violations of which may result in the imposition of fines and reputational damage; our risk management and internal controls may not be successful in preventing or detecting all violations of law or of company-wide policies.

In addition to environmental and electricity industry regulations, our business is subject to a significant number of laws, rules and regulations, including those relating to competition and antitrust, anti-bribery and anti-corruption, health, safety and the environment, labor and employment, and taxation. We are subject, from time to time, to investigations and proceedings by authorities for alleged infringements of these laws. These proceedings may result in fines or other forms of liability and could have a material adverse effect on our reputation, business, financial condition and results of operations.

Our existing compliance processes and internal control systems may not be sufficient to prevent or detect all inappropriate practices, fraud or violations of law by our employees, officers or agents. We may in the future discover instances in which we have failed to comply with applicable laws and regulations or internal controls. If any employees or other persons engage in fraudulent, corrupt or other unfair business practices or otherwise violate applicable laws, regulations or internal controls, we could become subject to one or more enforcement actions or otherwise be found to be in violation of such laws, which may result in penalties, fines and sanctions and in turn adversely affect our reputation, business, financial condition and results of operations.

Labor laws currently in effect may negatively impact us.

As of the date of this offering memorandum, none of ILAP, San Juan nor Norvind have employees, and the operation of the energy generating plants is handled by third party contractors. Likewise, labor and bookkeeping aspects are covered under a management agreement with LAP Chile, pursuant to which San Juan and Norvind pay LAP Chile a monthly fee. While this operation model mitigates many of the most common issues concerning labor relations, we remain liable for certain labor obligations under the relevant subcontracting provisions of the Chilean Labor Code, which hold companies jointly and severally responsible of the labor obligations of the contractors in certain circumstances. We are unable to predict the risk of insolvency or other managerial failures by any of the contractors or other service providers used by us in our current and future activities.

Recently, there have been some legislative efforts that could affect the operational costs of companies, including the possibility of increasing the percentage of retirement-related payments borne by the employer, which could entail a material effect in labor costs; together with the reduction of the working week to 40 hours a week, instead of the current 45 hours a week, which could increase the labor costs of the contractors of Norvind and San Juan, in case we may require additional employees to cover for such reduction. These costs, in turn, could be transferred to the price of the services currently subcontracted or outsourced by us.

The most immediate change to social security legislation relates to a government-endorsed bill proposing to increase the percentage of mandatory social security payments deducted from the employees' salaries, from the current 10% to 12%. Such 2% increase will be borne by the government and employers in equal parts. These changes, and other that may arise in the future, could impact labor costs associated with our operations and affect our income.

A cyber-attack could adversely affect our business, financial condition and results operation.

Information security risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication and activities of cyber-attacks as well as increased connections of equipment and systems to the Internet. In the event of a cyber-attack, we could have our business operations disrupted; experience losses and incur response costs; and be subject to litigation and damage to our reputation. A cyber-attack could adversely affect our business, results of operations and financial condition.

We may encounter significant competition from private companies, governments and state-owned companies.

The power generation industry is characterized by intense competition and we may encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for PPAs, which has contributed to a reduction in electricity prices where supply has surpassed demand plus appropriate reserve margins. Further, changes in technology may facilitate the entrance of new competitors, increase the supply of electricity or reduce the cost of methods of producing power that we do not currently use. If these technologies became cost competitive, we could face increasing competition

In addition, the Chilean government has exercised and continues to exercise substantial influence over many aspects of the private sector. In some cases, the government owns or controls many companies, including some of the largest in Chile. The availability of investment opportunities depends in part on the government continuing to liberalize its policies regarding private investment and to further encourage private sector initiatives. Increasing competition among participants in the power generation industry or from the government may negatively affect our results of operations and revenues.

Political conditions in the United States may adversely affect our results of operations and financial condition.

The Chilean economy and the market value of securities issued by Chilean issuers may be, to varying degrees, affected by economic and market conditions in other emerging market countries and in the United States. Adverse economic conditions in the United States, such as those caused by the current COVID-19 outbreak or other related events could have an adverse effect on the Chilean economy. Although economic conditions in other emerging market countries and in the United States may differ significantly from economic conditions in Chile, investors' reactions to developments in other countries may have an adverse effect on the market value of securities of Chilean issuers. There can be no assurance that future developments in other emerging market countries and in the United States, over which we have no control, will not have a material adverse effect on our ability to service our debt, which could adversely affect the market price of the Notes.

Information included in the Independent Market Report and the Independent Engineer Report, including projections or estimates may prove to be incorrect, which may affect our ability to pay our obligations under the Notes.

This offering memorandum contains expert opinions on matters related to projected energy flows, energy and capacity prices, demand factors, node factors, and supply of and demand for electricity, among others. Any projections or estimates contained in the Independent Market Consultant Report or the Independent Engineer Report were made using various analytical methodologies and are based on numerous assumptions, including assumptions in respect of material contingencies and other matters beyond our control, including, among others, the GDP of Chile, energy prices and demand and availability factors, among others. The Independent Market Consultant Report and the Independent Engineer Report contain important discussions of the projections and estimates and of the assumptions used in their preparation.

We urge you to read the Independent Market Consultant Report and the Independent Engineer Report in their entirety before making a decision to invest in the Notes. The Independent Market Consultant and the Independent Engineer prepared their respective opinions on the basis of assumptions and estimates that believed to be reasonable at the time. However, these assumptions and estimates, as set forth in the Independent Market Consultant Report and the Independent Engineer Report may not be accurate and actual results may be materially different. Even if the assumptions and estimates are accurate, the actual revenues, expenditures, expenses and energy demand may differ materially from those expressed in the Independent Market Consultant Report and the Independent Engineer Report. We urge you not to place undue reliance on any projections included in the Independent Market Consultant Report and Independent Engineer Report, and elsewhere in this offering memorandum.

No undue reliance should be placed on forward-looking statements and estimates included in the models and projections included herein

The projections contained in the Independent Market Consultant Report and the Independent Engineer Report contain forward-looking statements and estimates, including certain potential financial results for the period 2021 through 2033. These forward-looking statements and estimates reflect current expectations and projections about future events based on present facts and circumstances and assumptions about future events (which may not occur). These statements and estimates are not necessarily indicative of future results and involve risks and uncertainties that could cause actual results to differ materially from our expectations. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could have an adverse effect on us, include those described under "*Forward-Looking Statements*" and elsewhere in this "*Risk Factors*" section.

The forward-looking information included in the Independent Market Consultant Report and the Independent Engineer Report was not prepared in compliance with the published guidelines of the SEC, the International Federation of Accountants, IFRS or any other relevant organization, regarding projections or forecasts, and are based on numerous assumptions relating to factors that are outside of our control and may or may not be realized. For the foregoing reasons and because our business is subject to numerous risks, uncertainties and other factors, including those set forth in this "*Risk Factors*" section, investors should not place undue reliance on the information and forward-looking information in the Financial Model as an estimate or prediction of future performance. Actual results may differ from those reflected in the forward-looking information included in the Financial Model, and the differences could be material.

Neither our independent auditors nor any other independent accountant, or any other person, including the Initial Purchasers, has compiled or examined the forward-looking information in the Independent Market Consultant Report and the Independent Engineer Report, and our independent auditors disclaim any association with such forward-looking information. We disclaim any obligation to update the information in the Independent Market Consultant Report and the Independent Engineer Report or disclose any difference between our actual results and those reflected in such forward-looking information.

Risks Relating to the PEC Receivables

Each PEC Receivable is the obligation of a specified Chilean DisCo, and not of the Republic of Chile.

The sole obligor of each PEC Receivable is the DisCo identified as such in the Tariff Decree pursuant to which that PEC Receivable is recognized, and that DisCo is the only person required to make payments due on that PEC Receivable. The Republic of Chile is not the obligor of any PEC Receivable. Although various Chilean governmental entities are required to perform certain actions with respect to the PEC Receivables under the Tariff Stabilization Framework, neither Chile nor any of those Chilean governmental entities is required to make payments due on the PEC Receivables. We have no obligations under the PEC Receivables or the Tariff Stabilization Framework with respect to the payment of the PEC Receivables, but we are required to issue related invoices within three Chilean business days after the publication of each PEC Receivable Payment Chart on the National Electrical Coordinator's website.

We will have no recourse against the Republic of Chile or any governmental authority with respect to a shortfall in payments due on any PEC Receivable unless the relevant Chilean governmental entities fail to perform certain actions required under the Tariff Stabilization Framework.

Furthermore, no DisCo will be an obligor of a PEC Receivable unless that DisCo is expressly identified as the obligor of that PEC Receivable in the Tariff Decree pursuant to which that PEC Receivable is recognized. In addition, there can be no assurance that a DisCo that is the obligor of a PEC Receivable (a) will be able to pay that PEC Receivable in full, (b) will not be dependent on reallocations from other DisCos at the instruction of the National Electrical Coordinator, or (c) will have sufficient funds otherwise available to it to make out-of-pocket payments on the PEC Receivables.

Our claims against the DisCos for failure to make payments on the PEC Receivables may not be successful or may be subject to defenses.

A DisCo's obligation to make payments on its PEC Receivables arises from the Tariff Decree recognizing the generation of such PEC Receivables. The timing of those payments will be determined by the National Electrical Coordinator's issuance of the PEC Receivable Payment Charts as a result of (a) the generation of surpluses and, if applicable, (b) the inclusion of additional amounts to ensure that all PEC Receivables are paid in full by December 31, 2027. In general, we, as holder of that PEC Receivable, would have a claim against a DisCo if that DisCo failed to make a payment on a PEC Receivable within six Chilean business days after the publication of a PEC Receivable Payment Chart on the National Electrical Coordinator's website. If payment of a PEC Receivable has not been made by December 31, 2027, because no PEC Receivable Payment Chart has been issued for the payments expected to be due and payable as of such date, we, as holder of that PEC Receivable, or the Onshore Collateral Agent, may initiate ordinary actions against the obligor of that PEC Receivable; however, the applicable DisCo is likely to argue that in the absence of a PEC Receivable Payment Chart, it is not required to make payments and that we should seek recourse against the National Electrical Coordinator, the Ministry of Energy or the CNE, as applicable. There can be no assurance that an obligor will not be successful in asserting this or another defense.

The outcome of a DisCo's insolvency proceeding is uncertain, and the Tariff Stabilization Law does not provide guidance as to the treatment of the PEC Receivables in case of the insolvency or liquidation of a DisCo.

No DisCo has been liquidated as a result of becoming insolvent or declared bankrupt or undergone a voluntary or forced liquidation proceeding, and there is only one case of a DisCo that was subject to a creditors' agreement composition (*convenio preventivo*) in accordance with Chilean insolvency law (in force before the enactment of the Bankruptcy Law); therefore, there is very limited case law and practical experience with respect to how the applicable regulators and courts would handle or resolve the insolvency or liquidation of a DisCo.

The Tariff Stabilization Framework does not expressly provide guidance as to the treatment of the PEC Receivables in case of the insolvency or liquidation of an obligor; therefore, there is no certainty as to whether the holders of a PEC Receivable would participate in any insolvency, bankruptcy, reorganization or other similar proceedings of the obligor of that PEC Receivable and to what extent those proceedings would impact the timing and the amount of payments payable by the obligor under the PEC Receivable.

In the event of a payment default in respect of a PEC Receivable, the balance of that PEC Receivable that has not been included in a PEC Receivable Payment Chart and is not yet due and all other PEC Receivables will not be subject to acceleration.

Although all PEC Receivables must be paid in full by December 31, 2027, individual payments will become due following the National Electrical Coordinator's issuance of the PEC Receivable Payment Charts. Unless a resolution of liquidation is issued against a DisCo, its failure to make any payment on a PEC Receivable when due will not result in the acceleration of (i) any balance of that PEC Receivable that is not yet due, (ii) any other PEC Receivables of that DisCo or (iii) any PEC Receivable of any other DisCo.

The Ministry of Energy and the other Chilean governmental entities may fail to take the steps necessary to approve tariff increases.

Pursuant to the Tariff Stabilization Framework, all PEC Receivables must be paid by December 31, 2027. Although the PEC Receivables are expected to be paid from surpluses that the Chilean electricity system is expected to generate over time, if the CNE projects in its semi-annual definitive technical reports to be issued in 2024 that surpluses generated and to be generated will not be sufficient to pay all PEC Receivables in full by December 31, 2027, the CNE is required to recommend tariff increases from 2025 to 2027. The responsibility to increase tariffs based on those recommendations ultimately lies with the Ministry of Energy. There can be no assurance that tariff increases will occur.

There can be no assurance that the CNE will include the adjustment factor to increase tariffs in its preliminary and definitive technical reports and, subsequently, that the Ministry of Energy will issue Tariff Decrees applying those increases in tariffs as they may be needed to ensure that all PEC Receivables are paid by December 31, 2027. If sufficient surpluses are not generated to pay all PEC Receivables in full by December 31, 2027 and the CNE does not include sufficient additional amounts in the technical reports issued during 2027 and such additional amounts are not recognized in the relevant Tariff Decree and PEC Receivable Payment Chart, the DisCos that are the obligors of those PEC Receivables may fail to make payments on those PEC Receivables and the prospects of success of a claim against DisCos for the unpaid PEC Receivables is uncertain.

If the CNE or the Ministry of Energy were to fail to perform the actions required to ensure that surpluses are generated so that PEC Receivables are paid in full by December 31, 2027, we would be entitled to file a claim against the CNE or the Ministry of Energy seeking damages resulting from that failure, but the success of such a claim is uncertain.

Even if the CNE recommends and the Ministry of Energy approves tariff increases, the assumptions and projections used to calculate the amounts of those tariff increases may prove incorrect or may not be realized.

Under the Tariff Stabilization Law, the CNE is required to ensure that sufficient surpluses are generated to pay all PEC Receivables in full by December 31, 2027. The CNE is required to base both the recommendation to increase tariffs and the amounts of those increases on projections it is required to include in each technical report covering a Tariff Period starting after December 31, 2024. These projections will likely be based on assumptions, including with respect to macroeconomic conditions, future PPA prices and the expected electricity supply and demand. Should any of the CNE's assumptions prove materially incorrect or fail to materialize as expected, tariff increases may not generate sufficient surpluses to pay all PEC Receivables in full by December 31, 2027.

We and, in turn, Investors have limited remedies for the failure by Chilean government entities to perform certain actions required under the Tariff Stabilization Framework, and pursuing those remedies may be difficult.

The Tariff Stabilization Framework requires Chilean government entities to carry out certain actions whose performance is material to the ability of the DisCos to pay the PEC Receivables in accordance with the Tariff Stabilization Framework. However, the Tariff Stabilization Framework does not set out specific remedies against Chile, the Ministry of Energy, the CNE, the National Electrical Coordinator or any other Chilean government entity for non- performance of such actions under the Tariff Stabilization Mechanism.

Available claims

Pursuant to generally applicable law in Chile, should the Ministry of Energy or the CNE fail to comply with its obligations under the Tariff Stabilization Framework, we, as holder of the PEC Receivables, could (a) bring a claim for damages against the non performing governmental authority in Chilean courts for an unlawful failure to act that gives rise to state liability (*responsabilidad estatal por falta de servicio*) under the Chilean Constitution and Chilean law No. 18,575, (b) petition the Comptroller General (i) to instruct the non-performing governmental authority to carry out the actions it failed to perform and (ii) to initiate administrative proceedings against the public officials who failed to perform those duties, or (c) petition the relevant Chilean Court of Appeals to issue a constitutional injunction (*recurso de protección*) on the non-performing governmental authority for the violation of the fundamental right to property and equal treatment under the law.

Failure by the National Electrical Coordinator to issue a PEC Receivable Payment Chart instructing a DisCo to make payments on its PEC Receivables could give rise to claims for damages under general principles of the Chilean Civil Code. Furthermore, any claims against the National Electrical Coordinator would need to be brought under general principles of private law or as constitutional injunctions (*recursos de protección*). Finally, although failure by the Comptroller General to validate a Tariff Decree could delay the Ministry of Energy's issuance of that Tariff Decree, there is no precedent of a claim for damages or constitutional injunction claims against the Comptroller General, for failing to validate Tariff Decrees or other acts similar to Tariff Decrees before the applicable deadline.

There is limited precedent for claims against Chilean governmental entities for unlawful failure to act (*falta de servicio por omisión*), and there can be no certainty as to what standard Chilean courts will apply in each case.

Timing of claims

In addition, some of these claims can only be brought within a limited timeframe. For example, constitutional injunctions must be brought within 30 days after the alleged violation of a fundamental constitutional right occurs, claims brought before the Experts' Panel for mistakes included in PEC Receivable Payment Charts (subject to the limitations described above) must be brought within 15 days after the National Electrical Coordinator publishes the PEC Receivable Payment Chart on its website, and general administrative claims (*recursos de reposición*) must be brought within five Chilean business days after the claimant receives notice of the respective administrative act or decision. As a result, so long as there is standing, we or the Onshore Collateral Agent may fail to bring the applicable claim in time unless proper instructions or powers of attorney are given in advance.

Source of funds

Judgments entered against certain governmental entities provide recourse only to the applicable entities' assets. Although a judgment entered against the Ministry of Energy would be satisfied from the general assets of the Republic of Chile, a judgment entered against the CNE or the National Electrical Coordinator would be satisfied only from the specific assets of that entity, which are treated as independent from those of the Chilean state. Should the

CNE's assets not be sufficient to satisfy a judgment, the Chilean government and the Chilean Congress could appropriate additional funds for that purpose in the general annual budget for the following year or the Chilean government could make a direct transfer to the CNE to satisfy the unpaid portion of a judgment. Should the National Electrical Coordinator's assets be insufficient to satisfy a judgment, the National Electrical Coordinator would not be permitted to obtain additional funding from the Chilean government through budgetary appropriations or direct transfers. There are no precedents for claims for damages brought against the National Electrical Coordinator. The National Electrical Coordinator's budget is funded by Regulated Customers and Unregulated Customers through a "public service fee" included in the tariffs calculated and fixed pursuant to a regulation of the CNE. The National Electrical Coordinator does not receive government contributions.

There can be no assurance that, if any Governmental Authority fails to comply with its obligations under the Tariff Stabilization Framework, any claim that we or the Collateral Agent acting as per the instructions of the holders of the Notes may have against that entity will be successful or, if successful, that any damages awarded and paid will be sufficient to pay the amounts due to us on the PEC Receivables. If a Governmental Authority's failure to perform the duties required by it under the Tariff Stabilization Framework results in a shortfall in funds for DisCos to make payments due on the PEC Receivables, and we cannot bring a successful claim against the Republic of Chile or the applicable governmental authority, we would not have sufficient funds to make payments due on the Notes and it may not be able to recover that shortfall in an enforcement scenario in a timely manner or at all. Under the Indenture, we are not obligated to pursue any of the foregoing claims.

Issuance by the Ministry of Energy and confirmation by the Comptroller General of a Tariff Decree does not ensure it will not be challenged.

When the Comptroller General confirms a Tariff Decree, the decree is presumed to be legally valid; nevertheless, any legal entity or person that is regulated or materially affected by the content of a Tariff Decree can challenge that Tariff Decree through administrative avenues (general administrative claims or invalidation requests) and judicial avenues (constitutional injunctions (*recursos de protección*) or public annulment claims), and the Ministry of Energy can invalidate that Tariff Decree *ex-officio*. The respective court or the Ministry of Energy, as applicable, is permitted to annul or revoke a Tariff Decree if the Tariff Decree contravenes the law, the Ministry did not follow the proper administrative procedure for issuing the Tariff Decree or, depending on the specific circumstances, if the Tariff Decree infringes on constitutional rights. An invalidated or revoked Tariff Decree would cease to be in force, and the previous Tariff Decree would become valid until a new Tariff Decree is issued. Once the invalidated Tariff Decree is correctly reissued, it is likely that the new Tariff Decree would incorporate adjustments to account for shortfalls or excesses in payments made under the invalidated Tariff Decree or as a result of the application of the previous Tariff Decree beyond its intended period of applicability. There is no precedent of a Tariff Decree being invalidated or revoked after its confirmation by the Comptroller General; however, there can be no assurance that future Tariff Decrees will not be invalidated or revoked, and it is uncertain whether a replacement Tariff Decree would include proper adjustments to compensate for any shortfalls or excesses. Invalidation or revocation of a Tariff Decree could have a material adverse effect on the timely generation of surpluses, the issuance of PEC Receivable Payment Charts, the timing of the DisCos' payments on the PEC Receivables, the DisCos' ability to make payments on the PEC Receivables and, in turn, our ability to make payments on the Notes.

There can be no assurance that the Tariff Stabilization Framework or other tax or other laws or regulations affecting the PEC Receivables will not change.

There can be no assurance that ongoing or future social unrest, civil disruptions or other factors, including prolonged consequences of the COVID-19 pandemic, will not cause the Chilean government to implement changes to the Tariff Stabilization Framework or the PEC Receivables, including the Purchased Receivables, that are material and adverse to us.

The Tariff Stabilization Framework could be modified by the Chilean Congress through the enactment and modification of related laws, which must be approved by a simple majority of the Chilean Congress, and could also be modified by the relevant Chilean government entities, including the CNE and the Ministry of Energy, through the issuance and modification of related regulations. Any changes in future laws and regulations could even have retroactive effect and adversely affect the PEC Receivables. Although changes of these types may give rise to clams against various government entities, there can be no assurance that any such claim would be successful or that any recovery would be timely or sufficient to cover losses to us.

A modification of the Tariff Stabilization Framework could have a material adverse effect on our rights and remedies with respect to the PEC Receivables and, as a result, a material adverse effect on our ability to make payments due on the Notes. If a modification affects our right to property and the modification was approved other than by law, we would be entitled to request that the Chilean Supreme Court grant a constitutional injunction (*recurso de protección*) requiring the modification to be revoked. If a modification is made by law, during the discussion of the bill of law in the Congress, only the President of Chile, one of the Chambers of Congress or a quarter of its members are entitled to object the constitutionality of the bill before the Constitutional Court. Once the bill of law has been enacted into law, the judge or the persons who are part of any pending judicial proceeding in which the application of the law is decisive to resolve the matter, would be entitled to request the inapplicability of the law for its unconstitutionality. The declaration of inapplicability of a law due to its unconstitutionality will only have effect on the respective judicial proceeding; however, if the law has been declared at least once inapplicable as unconstitutional, the Constitutional Court may declare *ex-officio* or upon any person's request the unconstitutionality of the law with general effects and the law will be considered repealed. There can be no assurance that we would obtain a desired constitutional injunction, or that any of the persons entitled to request that a modification be declared unconstitutional will do so successfully or at all. In addition, criteria applied by the Constitutional Court and the Chilean Supreme Court to reach a judgment may vary based on extraordinary emergency powers and other rights, powers and protections that Chile, as a sovereign State may have.

In addition, a change in tax law in Chile affecting us could have a material adverse effect on our cash flows. Under Chilean law, there is currently no withholding tax imposed on the payment of PEC Receivables. If, however, in the future the laws in Chile were changed to require the DisCos to deduct or withhold any taxes, duties, assessments or governmental charges in respect of the PEC Receivables, payment by the DisCos to the holders of the Receivables would be made net of those taxes, duties, assessments or governmental charges. The DisCos have no obligation to "gross up" or pay any additional amounts to the holders of the PEC Receivables if changes in law result in withholding or deductions. As a result, should any such changes occur, we may not have sufficient funds to make payments on the Notes.

The Tariff Stabilization Framework does not have a similar precedent under Chilean legislation.

Although the regulatory framework that governs the Chilean electricity industry has been in place since the 1980s, the Tariff Stabilization Framework is the first mechanism of its kind to be employed in Chilean electricity pricing, and it contains features with respect to which there is no, or very limited, legal and regulatory interpretative history. As of the date of this offering memorandum, there are no existing administrative or judicial interpretative precedents for many of the key features of the Tariff Stabilization Framework. The regulatory, administrative and judicial uncertainty surrounding the Tariff Stabilization Framework and its implementation could result in insufficient, delayed or otherwise uncertain cashflows to us and adversely and materially affect our ability to make payments on the Notes.

The Chilean electricity system may not generate sufficient surpluses to fund payments of the PEC Receivables as expected or at all without the CNE's approval of tariff increases.

The Tariff Stabilization Framework is premised on the expectation that the cost of electricity generation will decrease over time (primarily as a result of lower PPA prices awarded as a result of the introduction of renewable energy assets) and, therefore, if the tariffs charged to Regulated Customers are maintained or adequately increased, the Chilean electricity system will generate surpluses that will be available for DisCos to pay the PEC Receivables on or before December 31, 2027. The PEC Receivables are expected to be paid from surpluses that the Chilean electricity system is expected to generate from the positive difference between (a) the tariffs charged by the DisCos to Regulated Customers from time to time and (b) the prices payable by the DisCos under PPAs from time to time. Nevertheless, the Chilean electricity system could fail to produce the expected surpluses for various reasons. Although prices under PPAs that have already been awarded and become effective in 2021 are lower than current PPA prices, if the prices payable by DisCos to generation companies under adjudicated PPAs are renegotiated or otherwise modified or if PPAs to be adjudicated in the future provide for higher-than-expected prices, the PNLPs, which average PPAs prices over a

Tariff Period, will similarly increase and, as a result, the difference between the PNLP and the PEC or Adjusted PEC for that Tariff Period will decrease or may be zero.

Future PNLPs are expected to decrease as a result of the expected introduction of renewable generation assets into the Chilean electricity generation matrix. PPA prices reflect the cost to the generation companies of generating the electricity to be sold under those PPAs. Because renewable energy plants use low-cost or freely available natural resources to generate electricity, the introduction of renewable generation assets into the Chilean generation portfolio is expected to reduce generation costs and, by extension, PPA prices and PNLPs. If renewable energy assets are not introduced at the rates expected or if the impact they have on PPA prices is less than expected, the Surpluses expected to be generated by these price decreases may be limited or may be zero.

In addition, because PNLPs are based on PPA prices, which are denominated in U.S. Dollars, and the PEC and Adjusted PEC (the tariffs that DisCos are entitled to charge Regulated Customers) are denominated in Pesos, a depreciation of the Peso against the U.S. Dollar during the period preceding a Tariff Decree would reduce (and could even eliminate) the positive difference between the PEC or Adjusted PEC and the PNLPs that DisCos are required to pay the generation companies. Any such depreciation of the Peso against the U.S. Dollar may be significant and reduce the rate at which surpluses are generated.

If surpluses are not generated as quickly as expected or at all, whether due to any of the foregoing or other reasons, including if the CNE fails to increase tariffs, the DisCos may not have sufficient funds available to make payments on the PEC Receivables. Although the Tariff Stabilization Framework contemplates a mechanism to increase tariffs to make up for a shortfall in surpluses, there can be no assurance that that mechanism will be implemented properly or at all.

Risks Related to Chile

Chilean political and economic conditions may adversely affect our business and the market price of the Notes.

Our main business operations and assets are located in Chile and all of our customers are Chilean companies. In the past, unfavorable general economic conditions, including the 2008 financial crisis that affected the global banking system and financial markets, have caused a decrease in the amount of foreign capital invested in emerging markets, including Chile and Latin America. In turn, this caused securities markets in many emerging markets, including Chile and Latin America, to decrease in value and led to depreciation of emerging market currencies compared to the U.S. Dollar. Because international investors' reactions to the events occurring in one market sometimes affect other regions or disfavor certain investments, the Chilean economy could be adversely affected by negative economic or financial developments in other countries, such as those related to the current COVID-19 outbreak and civil unrest that begun in October 2019. We cannot assure you that negative developments in Latin America or other emerging markets or in developed economies will not occur or that such negative developments would not adversely affect the securities markets in which the Notes trade or affect our access to sources of financing.

The Chilean economy has recently experienced a slowdown in growth, and we cannot assure you that the Chilean economy will grow in the future or that future developments in or affecting the Chilean economy, including further consequences of economic difficulties in Brazil, Argentina and other emerging markets or in the financial markets of developed economies, will not impair our ability to proceed with our business plan or materially adversely affect our business, financial condition or consolidated results of operations.

Although Chilean inflation has decreased in recent years, Chile has experienced high levels of inflation in the past. High levels of inflation in Chile could adversely affect the Chilean economy and have an adverse effect on our results of operations if the high inflation is not accompanied by a matching devaluation of the local currency. There can be no assurance that Chilean inflation will not revert to prior levels in the future. In addition, the measures taken by the Central Bank of Chile to control inflation have often included maintaining a tight monetary policy with high interest rates, thereby restricting the availability of credit and economic growth. A significant portion of our operating costs are denominated in Dollars and could therefore be significantly affected by a decrease in economic activity levels in Chile. If inflation in Chile were to increase without a corresponding depreciation of the Peso, or if the value of the Peso were to appreciate relative to the U.S. Dollar without the Peso experiencing corresponding deflation in Chile, the financial position and results of our operations as well as the value of the Notes could be materially and adversely affected.

The Chilean government has modified in the past and has the ability to modify monetary, fiscal, tax and other policies to influence the Chilean economy. We have no control over government policies and cannot predict how those policies or government intervention will affect the Chilean economy or, directly and indirectly, our business, consolidated results of operations and financial condition. Changes in policies involving exchange controls, taxation and other matters related to our sector may adversely affect our business, consolidated results of operations and financial condition and the market price of the Notes.

We are exposed to economic and political volatility, including civil unrest, in Chile, which could impact Chilean economy and our business, results of operations and financial condition in Chile. Starting in October 2019, Chile began to experience social turmoil, starting initially because of a fare hike in the Santiago subway system. Student and civil protests caused public and private sector property damage and disruption to institutions and commerce. The government initially declared a 90-day state of emergency, extendable as necessary, and at the same time, it launched various political, social, and economic reforms, and approved calling for a national referendum. However, the state of emergency lasted less than ten days.

On October 25, 2020, a constitutional referendum was held, where nearly 80% of voters elected to replace the Chilean Constitution which should be drafted by a special constitutional convention comprised of 155 citizens elected for that task only, from which there are 17 benches reserved only for members of the indigenous communities. The election for members of the special constitutional convention took place on May 15 and 16, 2021. See "*—The enactment of a new constitution in Chile may have a negative impact on our business and financial condition*." There can be no assurance that any future civil unrest will not adversely affect our business, results of operations, and financial condition in Chile.

The enactment of a new constitution in Chile may have a negative impact on our business and financial condition.

On November 15, 2019, representatives of Chile's leading political parties entered into an agreement to hold a referendum on whether the Chilean Constitution should be replaced and how the new constitution should be drafted. On October 25, 2020, the referendum was held and nearly 80% of voters elected to replace the Chilean Constitution and approved the motion of electing a special constitutional convention comprised of 155 citizens elected for the sole task of drafting the new Chilean Constitution, from which there were 17 benches reserved only for members of the indigenous communities. The citizen members of the special constitutional convention were elected on May 15 and 16, 2021, and the special constitutional convention is expected to deliver a final draft of the new constitution within a period of nine months from its inauguration (which is expected to take place no later than the first week of July 2021), which can be further extended up to a total of twelve months from its inauguration. Among the elected members, the majority group is of those who are independent to political parties, and virtually all sides of the political spectrum are represented. Additionally, there are 77 women and 78 men among the elected members (as a result of the gender equality regulations governing the election). The final draft of the new Chilean Constitution will be submitted to a further public referendum for its approval by simple majority vote (where the referendum will be of mandatory vote), which is expected to take place around mid-2022. It is difficult to determine how we could be affected by a new Chilean Constitution, if finally enacted, since there is still significant uncertainty regarding the process to approve it and further protests and political instability cannot be ruled out if approved and enacted. Given the highly regulated nature of our industry, any such constitutional reform (if approved) may have a material adverse effect on our business, financial condition or results of operations.

A severe earthquake or tsunami in Chile could adversely affect the Chilean economy and our infrastructure and, as a result, negatively impact our business, financial condition and consolidated results of operations.

Chile lies on the Nazca tectonic plate, one of the world's most seismically active regions. Chile has been adversely affected by powerful earthquakes in the past, including an 8.8 Richter Scale magnitude earthquake in central south regions in 2010, an 8.3 Richter Scale magnitude earthquake in Northern Chile in 2014 that caused several blackouts due to damage to the local electricity distribution network, and an 8.4 Richter Scale magnitude earthquake, in Northern Chile, in 2015. A 9.5 Richter Scale magnitude earthquake occurred in Valdivia, Chile in 1960, which remains the largest earthquake recorded in modern history.

A severe earthquake or tsunami in Chile could damage our facilities and have an adverse impact on the Chilean economy and on us, including our business, financial condition and consolidated results of operations. Our facilities are also susceptible to damage caused by fires and other catastrophic disasters arising from natural or accidental human causes, as well as acts of terrorism and health pandemics or other contagious outbreaks. A catastrophic event could cause disruptions in our business, significant decreases in our revenues or significant additional costs that may not be covered (or only partly covered) by our insurance. Furthermore, there may be lags between a major accident or catastrophic event and the final reimbursement from the insurance policies, which typically carry a deductible and are subject to per event policy maximum amounts.

Future increases in the corporate tax rate in Chile or additional modifications to the Chilean tax system to finance future social reforms may have a material adverse effect on our results of operations.

In the last decade several and substantial amendments have been made to the Chilean income tax system, including increases to corporate and personal income tax rates.

In February 2020, Congress enacted Law No. 21,210 (the "*2020 Chilean Tax Reform*") including several amendments to the Chilean tax system. Among these amendments, the 2020 Chilean Tax Reform provides for (i) elimination, effective as of January 1, 2020, of the coexistence of the attributed-income tax system and the consolidation of a single partially-integrated tax system for large companies, which was created in 2014, with a corporate tax rate of 27%, (ii) creation of a new special tax regime for small- and medium-sized companies, with a corporate tax rate of 25% that can be fully integrated with final taxes, (iii) gradual elimination of tax refunds that Chilean holding companies were able to claim for corporate taxes paid by their Chilean subsidiaries as a result of the absorption of holding companies' tax losses with dividends received from such subsidiaries, (iv) increasing the maximum tax bracket to 40% for the personal income tax applicable to resident individuals, (v) application of VAT to foreign digital services used in Chile and (vi) stricter requirements for private investment funds to benefit from preferential tax treatment.

In addition, based on Chile's current social and political environment after the civil unrest that started in October 2019, the Chilean government may introduce further tax reforms aimed at limiting tax exemptions and/or preferential tax treatments. The 2020 Chilean Tax Reform and the SII's (the Chilean tax authority) interpretation thereto, or the potential approval of future tax reforms, may have other consequences on us, and there can be no assurance that the current tax burden will not be adjusted in the future to finance future social reforms fostered by the Chilean government or to achieve other purposes, which may have a material adverse effect on our business, financial condition and results of operations.

In the event of any reorganization, liquidation or insolvency proceeding under the Bankruptcy Law involving Chilean entities, the rights and priorities with respect to the Collateral granted to the holders of Notes and the ability of holders of Notes to receive payments in respect of the Notes may be challenged.

In the event of any reorganization, liquidation or insolvency proceeding affecting us, it is possible that the Collateral pledged in favor of the Onshore Collateral Agent for the benefit of the holders of Notes may be subject to attachment, claw back or subordination in terms of relative priority in respect of the claims of third-party creditors of the Chilean entity pursuant to fraudulent conveyance or similar legal concepts (*acciones revocatorias*) under Chilean law. In such event, the granting of the security interest in the Collateral in favor of the Onshore Collateral Agent for the benefit of the holders of Notes would be subject to a mandatory, two-year claw back period beginning on the date that is two years prior to the commencement of such reorganization, liquidation or insolvency proceeding ("*claw back period*") being able to be rendered ineffective if it is proved before the court that such encumbrance (i) was entered with the counterparty's knowledge of the debtor's adverse business condition; and (ii) caused damages to the bankruptcy estate or that has affected the parity that should exist among creditors (e.g., that the transaction has not been entered into on terms and conditions similar to those usually prevailing in the market at the time of its execution). If the relevant elements under the Bankruptcy Law are met, then the appointed vendor or liquidator (trustee in bankruptcy), as the case may be, could seek from the Chilean court the setting aside or invalidation of the security interest granted on the Collateral in favor of the Onshore Collateral Agent for the benefit of the holders of Notes occurring during the claw back period.

In light of the foregoing, certain of the rights and priorities granted to holders of Notes, as well as payments in respect of the Notes, may be subject to challenge by our creditors in the circumstances set forth above.

The remedies available to holders, the Onshore Collateral Agent and the Indenture Trustee may be limited in bankruptcy under Chilean law.

If we seek the protection of bankruptcy or insolvency laws, or if one of our creditors begins a bankruptcy proceeding against us, the Onshore Collateral Agent's rights to foreclose on the Collateral and our ability to make payments in respect of the Notes are likely to be significantly impaired. In addition, we cannot predict how long payments on the Notes could be delayed, or if any payments on the Notes would be made, following the commencement of a bankruptcy case against us. Finally, because our contracts make up part of the Collateral, if any counterparty to any of those contracts were the subject of bankruptcy proceedings, then such counterparty, or a trustee appointed in the applicable bankruptcy case, could choose to reject the contract. If that occurred, the Onshore Collateral Agent would not be able to specifically enforce the rejected contract.

In addition, any bankruptcy or insolvency proceeding is likely to be subject to the insolvency and administrative laws of Chile, and we cannot assure that you will be able to effectively enforce your rights in any bankruptcy, insolvency or similar proceedings. In addition, the bankruptcy, insolvency, administrative and other laws of Chile may be materially different from, or in conflict with, each other, including in the areas of rights of creditors, priority of government entities and other third party and related party creditors' ability to obtain post-bankruptcy filing loans or to pay interest and the duration of proceedings. The laws of Chile may not be as favorable to your interests as the laws of those jurisdictions with which you are familiar. The application of these laws, or any conflict among them, could call into question what and how Chilean laws should apply. Such issues may adversely affect your ability to enforce your rights under the Notes in Chile or limit any amounts that you may receive.

Also, it is important to note that a secured creditor is generally free to apply the proceeds raised upon the foreclosure of its mortgage, pledge or other security interest to the amounts owed and secured thereby. In fact, a secured creditor usually does not need to return such proceeds to the estate or wait until the completion of the bankruptcy proceeding to receive them. In certain cases, however, if it appears that claims for preferred credits (i.e., statutory priorities) would not be satisfied in full from the proceeds of the sale of other assets of the debtor in bankruptcy, the secured creditors who have foreclosed on their collateral may be required to deposit a portion of the proceeds obtained therefrom to cover the existing deficiency or to otherwise secure payment thereof in full. If such credits cannot be satisfied with the proceeds obtained in the liquidation of other assets of the estate, such deposits would be applied to set off any existing deficiency and the secured creditors could be even required to return additional amounts if the deposits thus made are not sufficient to cover the existing deficiency, up to, along with the previously deposited amount, a total aggregate amount equal to the proceeds raised upon such foreclosure. Otherwise, the proceeds on deposit would be returned to the secured creditors up to the actual sum of money owed to them.

Such issues may adversely affect your ability to enforce your rights under the Notes in Chile or limit any amounts that you may receive.

Our environmental permits may be revoked or we may experience operational delays related to legal claims challenging our environmental permits that allow citizens affected by any environmental decision-making process to challenge the process or permit.

Our environmental permits may be revoked by the Supreme Court of Chile and other Chilean courts because citizens affected by any environmental decision-making process may petition for relief to a Chilean Court of Appeals, which has the power to require the suspension of the offending activity and to adopt protective measures through a constitutional protection remedy (*recurso de protección*).

The protection remedy challenge has been a widely utilized tool to obstruct and to delay projects. Moreover, environmental regulations provide specific claims to challenge environmental licenses (*recurso de reclamación*), along with remedies set forth in general administrative regulations that are frequently used to seek the revocation of granted environmental approvals (*solicitud de invalidación*). As a result, in the future, the resolution of our environmental permits (RCA) may be annulled or delayed through judicial action brought by the affected communities. These challenges may result in revocation of the approved permits and consequently, in a disruption of our operations.

Chile's changes to environmental regulations and policies may lead to significant changes in our industry and business.

Chile has adopted a number of policies and regulation that have benefited NCRE sources, like wind power, focusing on energy modernization, the social impact of energy, energy development, low emission energy, sustainable transport, energy efficiency and energy education and training. The current regulatory framework targets a 20% NCRE power generation requirement by 2025, which has been achieved in advance. Our facilities and operations are subject to a series of environmental laws and regulations, including, but not limited to, laws and regulations related to protected areas, licensing, use of dangerous products, and interface with indigenous territories, among others, which are becoming increasingly rigid and more strictly enforced and supervised. Furthermore, new or more rigorous environmental standards (including measures to address global warming) imposed on us, or a more rigorous application of such standards, could require us to expend additional funds in order to comply with such standards, which expenditure may be significantly longer than currently foreseen, which could have an adverse effect on our financial condition and results of operations.

As an example, new regulations enacted during 2019, such as the Tariff Stabilization Mechanism, could have a material adverse effect to our business by determining the final tariff paid by Regulated Customers not to be subject to increase prior to 2021 and cancelling a 9.2% price increase that occurred in mid-2019. There can be no assurance that these laws or any proposed new regulations will have no material adverse impact on our business, financial condition and results of operations.

Inflation in Chile may have an adverse effect on our business, results of operations and financial condition.

Historically, Chile has experienced high rates of inflation from time to time. Although inflation rates have been relatively low in recent years, we cannot assure you that this trend will continue. The annual rates of inflation and (deflation), as measured by changes in the CPI, in 2016, 2017, 2018, 2019 and 2020 were 2.7%, 2.3%, 2.6%, 2.2% and 3.1%, respectively. Although only a minor portion of our costs are denominated in Chilean Pesos, high levels of inflation in Chile could adversely affect the Chilean economy and have a material adverse effect on our business, results of operations and financial condition.

The Chilean Government could seize or expropriate our assets under certain circumstances.

Pursuant to Article 19 No. 24 of the Chilean Constitution, the Chilean Government may exercise its eminent domain powers in respect of our assets, in the event such action is required in order to protect public interests. According to Decree Law No. 2,186 of 1978, eminent domain powers may be exercised through an administrative expropriation process, the result of which can be appealed before a civil court. In the case of expropriation, we would be entitled to compensation for the expropriated assets. However, the compensation may be lower than the price for which the expropriated asset could be sold in a free market sale or the value of the asset as part of an ongoing business, which may adversely affect our ability to make payments under the Notes.

Chile has different corporate disclosure and accounting standards than those you may be familiar with in the United States and other jurisdictions.

Accounting, financial reporting and securities disclosure requirements in Chile differ in certain significant respects from those required in the United States. Accordingly, the information about us available to you will not be the same as the information available to holders of Notes issued by a U.S. company. In addition, although Chilean law imposes restrictions on insider trading and price manipulation, applicable Chilean laws are different from those in the United States, and the Chilean securities markets are not as highly regulated and supervised as the U.S. securities markets.

Risks Relating to the Notes and the Collateral

The Notes are a new issue of securities for which there is currently no public market. You may be unable to sell your Notes if a trading market for the Notes does not develop.

The offer and sale of the Notes have not been registered under the Securities Act or the securities law of any other jurisdiction and the Notes are being offered and sold only to QIBs within the meaning of Rule 144A under the Securities Act and in offshore transactions to persons other than U.S. persons pursuant to Regulation S under the Securities Act. The Notes will constitute a new issue of securities with no established trading market. If a trading market does not develop or is not maintained, or if the Initial Purchasers holds any significant portion of the Notes, holders of the Notes may experience difficulty in reselling the Notes or may be unable to sell them at all or the price of the Notes may be adversely impacted. Accordingly, an active trading market for the Notes may not develop. See "*Plan of Distribution*."

The Notes cannot and will not be publicly offered or sold to persons in Chile, and may be privately offered or sold in Chile only in circumstances which have not resulted and will not result in a public offering under Chilean law, and in compliance with CMF Rule 336. See "*Notice to Chilean Investors*." The definition of a public offering of securities under Chilean law includes both offers directed to the general public and offers directed to a part or specific group thereof.

The Notes are subject to certain mandatory redemption events without premium.

Upon the occurrence of certain events, the Issuer will be required to redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed without premium. See "*Description of the Notes—Cash Sweep Mandatory Redemption*"). Upon the occurrence of a change of control or certain events of loss, dispositions and other events described herein, the Issuer will be required to offer to purchase the Notes at the applicable prices set forth in this offering memorandum.

Changes in Chilean tax laws could lead to the redemption of the Notes.

Payments of interest in respect of the Notes made to foreign holders by us will be subject to Chilean interest withholding tax at a rate of 4.0%. Subject to certain exceptions, in general, we will pay additional amounts so that the amount received by the holder after Chilean withholding tax will equal the amount that would have been received if no such taxes had been applicable. If certain changes in applicable tax law occur, the Issuer may redeem the Notes, in whole but not in part, at a redemption price equal to 100% of the principal amount of the Notes being redeemed without premium, plus accrued and unpaid interest to, but excluding, the redemption date, plus any additional amounts. Although no proposal to increase the withholding tax rate in Chile is currently pending, we cannot assure you that an increase in withholding tax rate will not be presented to or enacted by the Chilean Congress.

There are restrictions on your ability to transfer the Notes.

The Notes have not been registered under the Securities Act or any state securities laws and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. Such exemptions include offers and sales that occur outside the United States in compliance with Regulation S under the Securities Act and in accordance with any applicable securities laws of any other jurisdiction and sales to QIBs as defined under Rule 144A under the Securities Act. For a discussion of certain restrictions on resale and transfer, see "*Plan of Distribution*" and "*Transfer Restrictions*." Consequently, a holder of Notes and an owner of beneficial interests in those Notes must be able to bear the economic risk of their investment in the Notes for the term of the Notes.

We may incur additional indebtedness ranking equally to the Notes or secured indebtedness.

We may incur additional debt that ranks on an equal and ratable basis with the Notes or is subordinated to the Notes, subject to certain restrictions described under "*Description of the Notes*." If we incur any additional debt that ranks on an equal and ratable basis with the Notes, the holders of that debt will be entitled to share ratably with the holders of the Notes, in any proceeds distributed in connection with an insolvency, liquidation, reorganization, dissolution or other winding-up of us subject to satisfaction of certain debt limitations, other than to the extent of the proceeds in the Collateral.

The Notes will be secured by a first priority lien on the Collateral. See "*Description of the Notes—Collateral*." Under the terms of the Indenture governing the Notes, additional secured indebtedness (including under additional Notes which would share in the Collateral) may be incurred if we satisfy a certain ratio and subject to certain other conditions. Accordingly, the incurrence of additional future secured debt, including through the issuance of additional Notes under the Indenture governing the Notes would dilute the value of the lien on the Collateral securing the Notes being offered herein.

The obligations under the Notes will be subordinated to certain statutory liabilities.

Under Chilean Bankruptcy Law, the obligations under the Notes are subordinated to certain statutory preferences. In the event of liquidation, such statutory preferences, including claims for salaries, wages, secured obligations, social security contributions, taxes and court fees and expenses, will have preference over any other claims, including claims by any investor in respect of the Notes.

Holders of the Notes may find it difficult or impossible to enforce civil liabilities against us or our directors, officers and controlling persons.

We are organized under the laws of Chile and our principal place of business is in Chile. All of our directors and our officers and controlling persons reside outside of the United States. In addition, all of our assets are located outside of the United States. As a result, it may be difficult for holders of Notes to effect service of process within the United States on such persons or to enforce judgments against them or us, including in any action based on civil liabilities under the U.S. federal securities laws. Based on the opinion of our Chilean counsel, there is doubt as to the enforceability against such persons in Chile, whether in original actions or in actions to enforce judgments of U.S. courts, of liabilities based solely on the U.S. federal securities laws.

In addition, your rights under the Notes will be subject to the insolvency and administrative laws of Chile, and we cannot assure that you will be able to effectively enforce your rights in any bankruptcy, insolvency or similar proceedings. In addition, the bankruptcy, insolvency, administrative and other laws of Chile may be materially different from, or in conflict with, each other, including in the areas of rights of creditors, priority of government entities and other third party and related party creditors', ability to obtain post-bankruptcy filing loans or to pay interest and the duration of proceedings. The laws of Chile may not be as favorable to your interests as the laws of those jurisdictions with which you are familiar. The application of these laws, or any conflict among them, could call into question what and how Chilean laws should apply. Such issues may adversely affect your ability to enforce your rights under the Notes in Chile or limit any amounts that you may receive.

Exchange controls and restrictions on foreign currency remittance could impede our ability to make payments under the Notes.

Exchange control risks include availability risk, the risk that even though we have sufficient Chilean Peso-denominated revenues to meet our obligations, U.S. Dollars are not available for conversion; convertibility risk, the risk that a Chilean government entity will restrict, condition or terminate our legal right to convert Chilean Pesos into U.S. Dollars; and transferability risk, the risk that a Chilean government entity will allow us to convert currency into U.S. Dollars, but will place restrictions or prohibitions on those U.S. Dollars leaving the country.

Chilean issuers are authorized to offer securities internationally complying with the provisions of Chapter XIV of the Compendium of Foreign Exchange Regulations of the Central Bank (the "*Chilean Central Bank Compendium*"), including the obligation to provide certain information to the Central Bank. Under Chapter XIV of the Chilean Central Bank Compendium, payments and remittances of funds from Chile are governed by the rules in effect at the time the payment or remittance is made. Therefore, any change made to Chilean laws and regulations after the date hereof shall affect foreign investors who have acquired the Notes.

There can be no assurance that further Central Bank regulations or legislative changes to the current foreign exchange control regime in Chile will not restrict or prevent us from acquiring U.S. Dollars; or further restrictions applicable to us which affect our ability to remit U.S. Dollars for payment of interest or principal on the Notes. There can be no assurance that restrictions applicable to the holders will not be imposed in the future, nor can there be any assessment of the duration or impact of such restrictions if imposed.

The ratings of the Notes may be lowered or withdrawn depending on various factors.

The ratings address the risk of default of payment of interest on each payment date. The ratings of the Notes are not a recommendation to purchase, hold or sell the Notes and the ratings do not comment on market price or suitability for a particular investor. Ratings are limited in scope, and do not address all material risks relating to an investment in the Notes, but rather reflect only the views of the rating agencies at the time the ratings are issued. The ratings of the Notes are subject to change and may be lowered or withdrawn. We cannot assure you that ratings will remain in effect for any given period of time or that ratings will not be lowered, suspended or withdrawn entirely by the ratings agencies, if, in the judgment of rating agencies, circumstances so warrant. A downgrade in or withdrawal of the ratings of the Notes will not be an event of default under the Indenture governing the Notes. The assigned ratings may be raised or lowered depending, among other things, on the rating agency's assessment of our financial strength, as well as its assessment of Chilean sovereign risk generally. Any lowering, suspension or withdrawal of ratings may have an adverse effect on the market price and marketability of the Notes.

Developments in other emerging markets may adversely affect the market value of the Notes.

Emerging markets, such as Chile, are subject to greater risks than more developed markets, and financial turmoil in any emerging market could disrupt business in Chile and adversely affect the price of the Notes. For example, as a result of the COVID-19 pandemic, certain Latin American countries are currently experiencing significant political and economic volatility, which may adversely affect prices in stock markets and prices for debt securities of issuers in other emerging market countries as investors move their money to more stable, developed markets. An increase in the perceived risks associated with investing in emerging markets could dampen capital flows to Chile and adversely affect the Chilean economy in general, and the interest of investors in the Notes in particular. We cannot assure you that the value of the Notes will not be negatively affected by events in other emerging markets or the global economy in general.

The ability of the Onshore Collateral Agent to foreclose on the Collateral securing the Notes may be limited pursuant to the Chilean Bankruptcy Law and the Electricity Law.

The Notes will be secured by the Collateral, as defined and described under "*Description of the Notes—Collateral*." The Collateral will generally consist of a first-priority security interest on our material tangible assets and the real estate property, rights under the PPAs, the equity interests or shares, as applicable, in each of ILAP and the Guarantors, as well as certain transaction accounts. The rights of the Onshore Collateral Agent as a secured party under the Collateral for the benefit of the holders of the Notes to foreclose upon and sell the Collateral upon the occurrence of a default may be significantly impaired by applicable bankruptcy laws if a bankruptcy, liquidation or reorganization proceeding were to be commenced by or against us. In particular, under the Bankruptcy Law and the Electricity Law, the right of a secured creditor to foreclose the Collateral may be affected in special circumstances during reorganization and liquidation proceedings.

We cannot predict whether or when the Onshore Collateral Agent could foreclose upon or sell the Collateral or whether or to what extent holders of the Notes would be compensated for any delay in payment or loss of value of the Collateral following the commencement, and during the pendency, of a bankruptcy case.

The value of the Collateral securing the Notes may not be sufficient to satisfy our obligations under the Notes.

The value of the Collateral in the event of liquidation will depend on many factors. The fair market value of the Collateral at any time is subject to fluctuations based on factors that include market, and other economic conditions, including the availability of suitable buyers. By their nature, some or all of the pledged or mortgaged assets may be illiquid and may have no readily ascertainable market value. We cannot assure you that the fair market value of the

Collateral as of the date of this offering memorandum exceeds the principal amount of the debt secured thereby. The value of the assets pledged or mortgaged as collateral for the Notes could be impaired in the future as a result of changing economic conditions, our failure to implement our business strategy, competition, unforeseen liabilities, timing and the manner of the sale and other future events.

Consequently, liquidating the Collateral securing the Notes may not result in sufficient proceeds to pay some or all amounts due under the Notes. If the proceeds of any sale of Collateral are not sufficient to repay all amounts due on the Notes, the holders of the Notes (to the extent not repaid from the proceeds of the sale of the Collateral) would have only a senior unsecured, unsubordinated claim against our remaining assets, and the obligations under the Notes will be subordinated to certain statutory limitations described above in this section.

The security over the Collateral will not be granted directly to the holders of the Notes.

The security interests in the Collateral that will secure the obligations under the Notes will not be granted directly to the holders of the Notes but will be granted in favor of the Onshore Collateral Agent for the benefit of the holders of the Notes and the other secured parties under the Indenture Documents. The Indenture and the security documents will provide that only the Onshore Collateral Agent has the right to enforce the Collateral. As a result, holders of the Notes will not have the right to enforce directly any security interests and will not be entitled to take enforcement action in respect of the Collateral or the Notes, except through the Onshore Collateral Agent and in accordance with, and subject to the terms of, the security documents.

Rights of holders of the Notes in the Collateral may be adversely affected by the failure to create or perfect security interests in certain Collateral on a timely basis or at all.

The Onshore Collateral Agent's ability to foreclose on the Collateral on the secured parties' behalf is subject to perfection and priority issues. We have agreed that the Notes will be secured by a first priority perfected security interest on the Collateral. See "*Description of the Notes—Collateral*." We cannot assure that all of the security interests in the Collateral will be effective (valid and enforceable) on the date the Notes are issued, or at all. We expect the necessary filings with the relevant Chilean registries for perfection of the security interest to become effective, in the case of the pledge over the Guarantors' assets, within 45 business days from the execution of each pledge, and in the case of the mortgages over the real estate property, within 60 calendar days from the date of execution of such mortgage]. Unless and until we take all necessary actions under Chilean law in Chilean jurisdictions where Collateral is located to create valid and enforceable security interests and, where applicable, perfect these security interests, holders of the Notes will not have valid and enforceable and perfected security interests in those portions of the Collateral. In addition, any inability or failure of the Collateral Agent to take all necessary actions under Chilean law in Chilean jurisdiction where Collateral is located to create properly perfected security interests in the Collateral in which we have agreed to perfect the security interests may result in the loss of the priority of the noteholders to such Collateral, to which they would have been entitled had the security interests been perfected prior to closing.

The security interests in portions of the Collateral may not be capable of, where applicable, perfection or registration according to customary established means of filing financing statements, recording charges, possession or otherwise. To the extent the security interest in any property or asset comprising part of the Collateral cannot be perfected or registered by established customary means, we may not be able to perfect or register such security interest in that portion of the Collateral. Moreover, the Onshore Collateral Agent for the Notes has no obligation to monitor the acquisition of additional property or rights that constitute Collateral or the perfection of any security interest in favor of the Notes against third parties.

Intercreditor provisions may restrict or limit the remedies that could be exercised by the holders of Notes.

On, before or after the Issue Date, the Issuer intends to enter into the LC Facility Agreement with Citibank, N.A. for purposes of issuing one or more standby letters of credit to fund the Debt Service Reserve Account and the O&M Reserve Account (as defined herein). The Issuer's obligations under the LC Facility Agreement would rank *pari passu* with the Notes, be secured ratably by the Collateral and be jointly and severally guaranteed by the Guarantors. Obligations under the LC Facility Agreement could result in lower debt service coverage ratios and less cash available to pay amounts due on the Notes. The rights of the holders of Notes and other secured obligations with respect to the Collateral will be subject to and may be limited by intercreditor arrangements in the Security and

Depositary Agreement as further described under "*Description of the Notes*." No holder of Senior Secured Obligations (as defined herein), including the holders of the Notes, will be entitled to take enforcement actions following an event of default unless the required percentage of Senior Secured Obligations has elected to exercise such remedies and instructed the respective Collateral Agent to take such actions in accordance with the procedures set forth in the Security and Depositary Agreement.

The Notes may not be a suitable investment for all investors seeking exposure to green assets.

Pursuant to the recommendation of the GBP, we engaged Standard & Poor's Financial Services LLC to provide an independent Second-Party Opinion to confirm the Notes' alignment with the key features of the GBP and GLP. The Second-Party Opinion is not incorporated into and does not form part of this offering memorandum.

There is currently no market consensus on what precise attributes are required for a particular energy project to be defined as "green" or "sustainable," and therefore we cannot assure you that the Projects will meet all investor expectations regarding environmental impact and sustainability performance. There is no guarantee as to the environmental impacts of the Projects. You should determine for yourself the relevance of information contained in this offering memorandum regarding the use of proceeds from this offering.

None of the Issuer, the Guarantors, the Initial Purchasers or the Trustee makes any representation as to the suitability of the Second-Party Opinion or the Notes to fulfill such environmental and sustainability criteria. The Second-Party Opinion may not reflect the potential impact of all risks related to the structure, market, additional risk factors discussed herein and other factors that may affect the value of the Notes. The Second-Party Opinion is not a recommendation to buy, sell or hold the Notes and is only current as of the date that the Second-Party Opinion was initially issued.

We have agreed to certain undertakings related to reporting and the use of proceeds as described under "*Use of Proceeds*;" however, it will not be an event of default under the Indenture governing the Notes if we fail to comply with such obligations. A withdrawal of the Second-Party Opinion or any failure by us to allocate an amount equal to the net proceeds from the offering of the Notes (less certain transaction expenses) to the refinancing of the Projects or to meet or continue to meet the investment requirements of certain environmentally focused investors with respect to the Notes may affect the value of the Notes and/or may have consequences for certain investors with portfolio mandates to invest in green assets.

The information found on, or accessible through, our website is not incorporated into, and does not form a part of, this offering memorandum or any other report or document appended hereto.

Investors may have limited remedies if we fail to satisfy related reporting requirements and other undertakings

Although we plan to make a sustainability report publicly available to our investors in our investor relations website, the Indenture and the Notes do not include covenants or agreements requiring us to satisfy the reporting and other undertakings described under the section "*Use of Proceeds*" below. As a result, it will not be an event of default under Indenture Documents if we fail to satisfy such reporting and other undertakings, and holders of the Notes will have no remedies under the Indenture Documents for any such failure.

USE OF PROCEEDS

The proceeds from the issuance and sale of the Notes on the Issue Date, after the deduction of expenses and the Initial Purchasers' discount associated with the offering payable on the Issue Date, and other transaction costs and expenses, are estimated to be approximately US$392 million.

After deduction of expenses and the Initial Purchasers' discount associated with the offering, we intend to use the entirety of the proceeds from the sale and issuance of the Notes to finance or refinance a pool of renewable energy Eligible Projects (as defined below) that meet the Eligibility Criteria (as defined below), that may qualify as eligible green projects under the Green Bond Principles 2018 ("*GBP*") and Green Loan Principles 2021 ("*GLP*"), by paying all outstanding obligations under the NPA (including the payment of a make-whole premium to existing noteholders).

The GBP are voluntary process guidelines for the issuance of green bonds, developed by a committee of issuers, investors and other participants in the social, green and sustainability bond markets, with the International Capital Market Association acting as Secretariat. We have obtained a Second Party Opinion from a consultant with recognized environmental and social expertise on the environmental benefits of the use of proceeds described herein as well as its alignment to the GBP and GLP. We believe the process described below is in alignment with the GBP.

Green Projects

"*Eligible Projects*" include the acquisition, development, construction, operation, maintenance and upgrades of wind energy generation projects with a minimum of 85% of electricity generated from wind energy resources (with the remaining 15% from other renewable sources), and other types of renewable energy generation projects that meet the Climate Bonds Standard, including its relevant asset specific criteria (the "*Eligibility Criteria*"). Eligible Projects include projects financed after the issuance of the Notes or up to 60 months prior to issuance.

The Projects qualify in the following categories of "green projects" set forth under the GBP:

- renewable energy; and
- pollution prevention and control.

The amounts from the issuance of the Notes will be used to refinance Eligible Projects on the Issue Date. Approximately 97% of the gross proceeds of the issuance of the Notes will be used to pay outstanding principal, interest and make-whole premium to the existing investors under the NPA.

We believe our financing framework is aligned with this component of the GBP and GLP because we commit to using the net proceeds of green bonds and/or loans issued under its framework to finance or refinance eligible wind energy generation and the related transmission infrastructure projects, which fits into the renewable energy category as defined in the GBP.

Project Evaluation and Selection

We have established a Green Finance working group which will be responsible for the ultimate review and selection of the pool of Eligible Projects. This working group comprises representatives from both ILAP and its shareholders, and includes team members responsible for construction oversight, operations and maintenance, permitting and due diligence, treasury, finance, investor relations as well as internal sustainability experts. This working group will identify and screen existing and future projects that align with the Eligibility Criteria and maintain a register of projects to track the Eligible Projects and the outstanding Notes.

We believe our green financing framework is aligned with this component of the GBP and GLP because it outlines how our Green Finance working group will approve and oversee the pool of Eligible Projects. The working group will be responsible for selecting projects that meet the defined eligibility criteria, including periodically revisiting whether projects continue to meet the criteria.

Management of Proceeds

The net proceeds from the issuance of Notes and the associated Eligible Projects will be tracked in our project register and reviewed and validated by our Green Finance working group on a semi-annual basis. We intend to use the proceeds from the issuance of the Notes for the repayment of our outstanding obligations under the NPA (as described above) on the Issue Date. We do not expect to have unallocated proceeds following the Issue Date.

Payment of principal and interest on the Notes will be made from our revenues, generally consisting in the price of energy we generate in our wind farms and sell to our Contracted Customers or in the spot market. Our business is wholly dedicated to renewable energy, and as such, proceeds from the issuance of Notes and revenues from our operations will not be invested in greenhouse gas intensive assets which are inconsistent with the delivery of a low carbon and climate resilient economy.

We believe that the green financing framework is aligned with this component of the GBP and GLP because the framework states that the allocation of proceeds to eligible green projects will be tracked under our project register, which the working group will review semi-annually.

Reporting

On an annual basis, we will make a sustainability report publicly available to our investors in our investor relations website (https://www.latampower.com/sustentabilidad). This website is not incorporated by reference into this offering memorandum. The report will include qualitative performance indicators, and where feasible, quantitative performance measures (e.g. energy capacity, electricity generation, greenhouse gas emissions reduced/avoided, number of people provided with access to clean power, etc.), together with key underlying methodology and/or assumptions used in the quantitative determination, together with a confirmation that the use of proceeds of our Notes comply with our Green Finance Framework.

Our reporting will include qualitative performance indicators and, where feasible, quantitative performance measures of the outcomes or impacts of the Eligible Projects (performance indicators may change from year to year). The Report may include some of the following data for Eligible Projects (i) total capacity of renewable energy production (MW); annual renewable energy generation (MWh); and greenhouse gas emissions reductions (tons CO2).

We believe our green financing framework is aligned with this component of the GBP and GLP because it commits to report annually on the funds allocated to the pool of eligible green projects and on the environmental impact of the financed projects.

The Initial Purchasers make no assurances as to (i) whether the Notes offered hereby will meet investor criteria and expectations regarding environmental impact and sustainability performance for any investors, (ii) whether the net proceeds will be used for the Projects (as defined herein), (iii) the characteristics of the Projects, including their environmental and sustainability criteria or (iv) the suitability of the Second-Party Opinion or the Notes to fulfill such environmental and sustainability criteria. The Initial Purchasers have not undertaken, nor are responsible for, any assessment of the, any verification of whether the Projects meet the eligibility criteria of the GBP or any monitoring of the use of proceeds. The Second-Party Opinion is not incorporated into and does not form part of this offering memorandum.

CAPITALIZATION

The following table sets forth the Company's capitalization as of March 31, 2021 (i) on a historical basis, and (ii) as adjusted to reflect the issuance of the Notes and the application of proceeds therefrom. See "*Use of Proceeds*" and "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Indebtedness*."

This table should be read together with the Unaudited Consolidated Financial Statements included elsewhere in this offering memorandum.

	As of March 31, 2021	
	Actual	As adjusted[1]
	(US$ thousands)	
Long-term indebtedness under NPA, current portion…………….	13,937	-
Long-term indebtedness under NPA, non-current portion[2]……...	375,298	-
Notes offered hereby[3]……………………………………….…...	-	403,900
Lease liabilities……………………………………………………	11,924	11,924
Other debt…………………………………………………………	-	-
Total debt[4]……………………………………………….…...	**401,159**	415,824
Total equity………………………………………………………	**(14,626)**	**(14,626)**
Total capitalization[5]…………………………………….……	**386,533**	**401,198**

(1) Adjusted to reflect the gross proceeds from issuance of the Notes of US$403,900 thousand.
(2) Does not include deferred financing expenses incurred in 2017 during the refinancing of the Projects under the NPA.
(3) Proceeds from the Notes will be used to pay all outstanding obligations under the NPA, as described under "*Use of Proceeds*."
(4) "*Total debt*" reflects the total of our financial obligations and is calculated as the sum of current and non-current portions of our indebtedness under NPA (excluding related deferred financing expenses) plus lease liabilities. We believe that total debt provides a useful indication of our financial position, including our ability to repay outstanding debt when comparing to our available cash and other highly liquid assets.
(5) Total capitalization is the sum of total debt and total equity.

EXCHANGE RATES

Chile has two currency markets, the formal exchange market (*mercado cambiario formal*), comprised of banks and other entities authorized by the Central Bank, and the informal exchange market (*mercado cambiario informal*), comprised of entities that are not expressly authorized to operate in the formal exchange market, such as certain foreign exchange houses and travel agencies, among others. Purchases and sales of foreign currencies that may be conducted outside the formal exchange market can be carried out on the informal exchange market at the "spot rate." Pursuant to current Chilean regulations, the Central Bank must be informed of certain transactions, and it is empowered to determine that certain purchases and sales of foreign currencies be carried out on the formal exchange market. Both the formal and informal exchange markets are driven by free market forces.

The observed U.S. Dollar to Peso exchange rate (*dólar observado*) (the "*Observed Exchange Rate*"), which is reported by the Central Bank and published daily in the Official Gazette (*Diario Oficial*), is computed by taking the weighted average of the previous business day's transactions on the formal exchange market. The Central Bank has the power to intervene by buying or selling foreign currency on the formal exchange market to attempt to maintain the Observed Exchange Rate within a desired range. During the past few years, the Central Bank has intervened to keep the Observed Exchange Rate within a certain range only under special circumstances. Although the Central Bank is not required to purchase or sell Dollars at any specific exchange rate, it generally uses spot rates for its transactions. Other banks generally carry out authorized transactions at spot rates as well.

As of December of 2019, the Central Bank decided to intervene in the exchange market by selling U.S. Dollars for a total amount of up to US$10,000 million and by selling FX hedging instruments for a total amount of up to US$10,000 million as well. Initially, this foreign currency selling program was intended to last until May 2020, but as one of the measures adopted to confront the COVID-19 pandemic, the Central Bank announced in March 2020 that the program would last until January 2021. In January 2021, the Central Bank announced a foreign currency buying program that is intended to last for 15 months and that contemplates buying U.S. Dollars for up to US$12,000 million.

The informal exchange market reflects transactions carried out at an informal exchange rate. There are no limits imposed on the extent to which the rate of exchange on the informal exchange market can fluctuate above or below the Observed Exchange Rate. In recent years, the variation between the observed exchange rate and the informal exchange rate has not been significant.

We make no representation that the Peso or the U.S. Dollar amounts referred to herein could have been or could be converted into U.S. Dollars or Pesos, as the case may be, at the rates indicated, at any particular rate or at all. The Federal Reserve Bank of New York does not report a noon buying rate for Pesos. The following table sets forth the annual low, high, average and period-end Observed Exchange Rate for U.S. Dollars for each year starting in 2017 and the months indicated below, as reported by the Central Bank.

Observed Exchange Rates (CLP per US$1.00)(1)(2)

Year	Low	High	Average	Period-End
2017	615.22	679.05	649.33	614.75
2018	588.28	698.56	640.29	694.77
2019	649.22	828.25	702.63	748.74
2020	710.26	867.83	792.22	711.24

(1) The table presents the annual low, high, average and period-end observed rates for each year.
(2) Reported on the first business day of the following year.

Observed Exchange Rates (CLP per US$1.00)(1)(2)

Month	Low	High	Average	Period-End
January 2021	696.18	741.40	723.56	741.40
February 2021	703.65	737.23	722.63	708.04

March 2021………..	716.46	738.46	726.37	732.11
April 2021	696.80	718.17	707.15	705.09
May 2021	693.74	734.75	712.26	724.92

(1) The table presents the annual low, high, average and period-end observed rates for each month.
(2) Reported on the first business day of the following month.

EXCHANGE CONTROLS

The Central Bank is the entity responsible for monetary policies and exchange controls in Chile. Chilean issuers are authorized to offer securities internationally provided they comply with, among other things, the provisions of Chapter XIV of the Compendium of Foreign Exchange Regulations (*Compendio de Normas de Cambios Internacionales*) of the Central Bank (the "*Central Bank Compendium*").

Pursuant to the provisions of Chapter XIV of the Central Bank Compendium, it is not necessary to seek the Central Bank's prior approval in order to issue the Notes. The Central Bank only requires that: (1) the remittance of funds obtained from the sale of the Notes into Chile be made through the formal exchange market and disclosed to the Central Bank as described below; and (2) all remittances of funds to make payments under the Notes made from Chile be made through the formal exchange market and disclosed to the Central Bank as described below.

The proceeds of the sale of the Notes may be brought into Chile or held abroad. If the Issuer remits the funds obtained from the sale of the Notes into Chile, such remittance must be made through the formal exchange market and the Issuer must deliver to the Central Bank directly or through an entity of the formal exchange market an annex providing information about the transaction, together with a letter instructing such entity to deliver us the foreign currency or the Peso equivalent thereof. If the Issuer does not remit the funds obtained from the sale of the Notes into Chile, the Issuer has to provide the same information to the Central Bank directly or through an entity of the formal exchange market within the first 10 days of the month following the date on which it received the funds. The regulations require that the information provided describe the financial terms and conditions of the securities offered, related security and guarantees, if any, and the schedule of payments.

All payments in connection with the Notes made from Chile must be made through the formal exchange market. Pursuant to Chapter XIV of the Central Bank Compendium, no prior authorization from the Central Bank is required for such payments in U.S. Dollars. The participant of the formal exchange market involved in the transfer must provide certain information to the Central Bank on the banking business day following the day of payment. In the event payments are made outside Chile using foreign currency held abroad, the Issuer must provide the relevant information to the Central Bank directly or through an entity of the formal exchange market within the first 10 days of the month following the date on which the payment was made.

Under Chapter XIV of the Central Bank Compendium, payments and remittances of funds from Chile are governed by the rules in effect at the time the payment or remittance is made. Therefore, any change made to Chilean laws and regulations after the date hereof will affect foreign investors who have acquired the Notes. The Issuer cannot assure you that further Central Bank regulations or legislative changes to the current foreign exchange control regime in Chile will not restrict or prevent the Issuer from acquiring U.S. Dollars or that further restrictions applicable to the Issuer will not affect the Issuer's ability to remit U.S. Dollars for payment of interest or principal on the Notes.

The above is a summary of the Central Bank's regulations with respect to the issuance of the Notes, as in force and effect as of the date of this offering memorandum. The Issuer cannot assure you that restrictions will not be imposed in the future, nor can there be any assessment of the duration or impact of such restrictions if imposed. This summary does not purport to be complete and is qualified in its entirety by reference to the provisions of Chapter XIV of the Central Bank Compendium, a copy of which is available from the Issuer upon request.

SELECTED FINANCIAL DATA

The selected financial and operating information presented below should be read in conjunction with "Presentation of Certain Financial and Other Information," "Summary Financial and Other Information," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements included elsewhere in this offering memorandum.

The Audited Consolidated Financial Statements have been audited by our current independent auditors, EY Chile. The report of EY Chile on such Audited Consolidated Financial Statements appear elsewhere in this offering memorandum.

The Consolidated Financial Statements have been prepared in accordance with IFRS. IFRS differs in certain respects from U.S. GAAP. We do not describe any differences between IFRS and U.S. GAAP in this offering memorandum. No reconciliation of any of our financial statements to U.S. GAAP has been prepared for this offering memorandum. Any such reconciliation could result in material quantitative differences. For further details and specific questions, investors should consult their professional advisors for an understanding of the differences between IFRS and U.S. GAAP. Historical results are not necessarily indicative of future expected results.

Income Statement Data

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Profit or loss					
Revenue	15,617	20,920	72,887	62,516	52,097
Cost of sales	(14,918)	(16,637)	(55,477)	(50,540)	(44,644)
Gross profit (loss)	**699**	**4,283**	**17,410**	**11,976**	**7,453**
Administrative expenses	(458)	(430)	(2,836)	(2,287)	(2,416)
Operating profit	**241**	**3,853**	**14,574**	**9,689**	**5,037**
Finance income	0	15	16	216	219
Finance expenses	(6,263)	(6,425)	(25,279)	(25,730)	(25,504)
Foreign exchange differences	(415)	(789)	(82)	48	(171)
Impairment charges	-	-	-	(4,665)	-
Loss before taxes	**(6,437)**	**(3,346)**	**(10,771)**	**(20,442)**	**(20,419)**
Income tax benefit (expense)	1,693	(524)	1,182	1,312	5,515
Loss for the period	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:					
Owners of the Parent	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Non-controlling interests	-	-	-	-	-
Other comprehensive income (loss)	**-**	**-**	-	-	-
Total comprehensive loss for the period, net of tax	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:					
Owners of the Parent	**(4,744)**	**(3,870)**	**(9,589)**	**(19,130)**	**(14,904)**
Non-controlling interests	**-**	**-**	**-**	**-**	**-**

Balance Sheet Data

	As of March 31,		As of December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Assets					
Current assets					
Cash and cash equivalents	2,639	7,692	7,363	18,428	13,313
Other financial assets	-	-	-	-	3,527
Trade and other current receivables	7,188	12,113	10,565	11,836	13,623
Accounts receivable from related entities	3,728	3,224	3,836	3,643	-
Inventory	93	-	63	-	-
Total current assets	**13,648**	**23,029**	**21,827**	**33,907**	**30,463**
Non-current assets					
Trade and other current receivables, non-current	12,063	6,299	11,742	1,245	-
Other non-current non-financial assets	-	-	-	-	258
Intangible assets other than goodwill	489	497	491	499	507
Goodwill	-	-	-	-	4,665
Property, plant and equipment	389,975	411,020	395,264	416,757	427,308
Deferred tax assets	37,791	34,393	36,098	36,149	33,604
Total non-current assets	**440,318**	**452,209**	**443,595**	**454,650**	**466,342**
Total assets	**453,966**	**475,238**	**465,422**	**488,557**	**496,805**
Equity and liabilities					
Current liabilities					
Other current financial liabilities	12,175	10,011	16,404	13,983	11,370
Trade and other payables	13,877	12,816	10,288	11,805	11,689
Accounts payable to related entities	4,889	4,600	4,902	4,724	744
Lease liabilities	362	362	362	343	-
Other non-financial liabilities	-	-		698	533
Total current liabilities	**31,303**	**27,789**	**31,956**	**30,855**	**24,336**
Non-current liabilities					
Other non-current financial liabilities	372,501	384,673	378,811	389,933	396,675
Provisions	53,226	51,892	52,885	51,615	50,258
Lease liabilities	11,562	11,847	11,652	12,014	-
Deferred tax liabilities	-	-	-	1,233	-
Accounts payable to related entities	-	-		-	3,499
Total non- current liabilities	**437,289**	**448,412**	**443,348**	**454,795**	**450,432**
Total liabilities	**468,592**	**476,201**	**475,304**	**485,650**	**474,768**
Equity					
Paid-in capital	89,801	93,001	89,801	93,001	93,001
Retained earnings (accumulated losses)	(99,683)	(90,094)	(90,094)	(70,964)	(70,964)
Result for the period	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Equity attributable to the owners of the Parent	(14,626)	(963)	**(9,882)**	**2,907**	**22,037**
Non-controlling interests	-	-	-	-	-
Total equity	**(14,626)**	**(963)**	**(9,882)**	**2,907**	**22,037**
Total equity and liabilities	**453,966**	**475,238**	**465,422**	**488,557**	**496,805**

Consolidated Statements of Cash Flows

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Cash flows from operating activities					
Loss before taxes	**(6,437)**	**(3,346)**	**(10,771)**	**(20,442)**	**(20,419)**
Adjustments to reconcile profit/loss to net cash flow:					
Depreciation	5,330	5,754	21,383	23,138	22,545
Foreign exchange differences	415	789	82	(48)	171
Finance expenses	6,263	6,425	25,279	25,730	25,504
Impairment charges	-	-	-	4,665	-
Changes in assets and liabilities					
Inventory	(30)	-	(63)	-	-
Trade and other account receivables	3,056	(5,825)	(9,226)	1,787	(1,504)
Other current assets	-	(66)	19	-	-
Trade payables and other current liabilities	3,589	1,093	(1,517)	(983)	3,699
Other non-financial assets and liabilities	(463)	(193)	(19)	(1,499)	147
Account receivable and payable with related entities	95	-	(14)	(2,519)	-
Other movements	-	-	-	-	102
Interest paid	(10,727)	(11,008)	(22,234)	(21,954)	(22,042)
Net cash flow generated by (used in) operating activities	**1,091**	**(6,377)**	**2,919**	**7,875**	**8,203**
Cash flows from investment activities					
Acquisition of property, plant, equipment and intangibles	-	(14)	(74)	(88)	(930)
Proceeds from short-term investments, net	-	-	-	3,526	(3,526)
Net cash flow generated by (used in) investing activities	**-**	**(14)**	**(74)**	**3,438**	**(4,456)**
Cash flows from financing activities					
Reduction of capital	-	-	(3,200)	-	(24,603)
Payment of principal portion of lease liabilities	(90)	(86)	(343)	(327)	-
Repayment of borrowings	(5,725)	(4,259)	(10,367)	(5,871)	(801)
Net cash flow used in financing activities	**(5,815)**	**(4,345)**	**(13,910)**	**(6,198)**	**(25,404)**
Effect of changes in exchange rates on cash and cash equivalents	-	-	-	-	-
Net increase (decrease) in cash and cash equivalents	**(4,724)**	**(10,736)**	**(11,065)**	**5,115**	**(21,657)**
Opening balance of cash and cash equivalents	**7,363**	**18,428**	**18,428**	**13,313**	**34,970**
Closing balance of cash and cash equivalents	**2,639**	**7,692**	**7,363**	**18,428**	**13,313**

Alternative performance measures

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Alternative performance measures					
Adjusted EBITDA[(1)]	5,571	9,607	36,887	33,741	28,509
Reconciliation of Adjusted EBITDA to Gain (Loss)					
Loss	(4,744)	(3,870)	(9,589)	(19,130)	(14,904)
Income tax (benefit) expense	(1,693)	524	(1,182)	(1,312)	(5,515)
Foreign exchange differences	415	789	82	(48)	171
Finance expense	6,263	6,425	25,279	25,730	25,504
Interests withholding tax	-	-	930	914	918
Finance income	-	(15)	(16)	(216)	(219)
Impairment charges	-	-	-	4,665	-
Depreciation and amortization	5,330	5,754	21,383	23,138	22,554
Adjusted EBITDA	**5,571**	**9,607**	**36,887**	**33,741**	**28.509**

(1) We define "*Adjusted EBITDA*" as gain (loss) after adding back (to the extent the number is negative) or subtracting (to the extent the number is positive), as the case may be, (1) income tax benefit (expense), (2) foreign currency exchange differences, (3) finance expense, (4) finance income, (5) Interests withholding tax, (6) impairment charges, and (7) depreciation and amortization. Adjusted EBITDA is not an IFRS measure but we consider it useful for investors as it presents a measure of our operational economic performance from management's perspective.

	As of March 31,		As of December 31,		
	2021	2020	2020	2019	2018
Operating Data					
Total installed capacity (MW)	**239.2**	**239.2**	**239.2**	**239.2**	**230.8**
Energy sales (GWh)					
PPA sales – Contracted Customers	133.7	192.8	609.9	532.9	359.9
Spot market sales	25.7	-	26.2	163.3	274.8
Total energy sales	**159.1**	**192.8**	**636.1**	**696.3**	**634.6**
Generation (GWh)					
Wind	135.1	113.4	671.8	700.0	722.1
Minus own consumption, maintance and losses	4.0	1.5	54.5	12.8	14.7
Curtailment	1.7	3.6	16.2	25.9	72.8
Net generation	**129.4**	**108.3**	**601.1**	**661.3**	**634.6**
Contracted Energy	30.0	30.0	35.0	35.0	0
Total energy available for sale before transmission	**159.1**	**138.3**	**636.1**	**696.3**	**634.6**
Purchases spot market	-	54.5	-	-	-
Total energy sales	**159.1**	**192.8**	**636.1**	**696.3**	**634.6**

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF OUR BUSINESS

The following discussion is based on the financial statements attached hereto and should be read in conjunction with the data set forth in "Summary of Financial and Other Information," "Capitalization," "Use of Proceeds," and "Selected Financial Data" and with our Audited Consolidated Financial Statements and the notes thereto, as of and for the years ended December 31, 2020, 2019 and 2018, prepared in conformity with IFRS and presented in U.S. Dollars, and our Unaudited Consolidated Financial Statements and the notes thereto, as of and for the three-month periods ended March 31, 2021 and 2020, prepared in conformity with IFRS and presented in U.S. Dollars.

This section contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Risk Factors" and the matters set forth elsewhere in this offering memorandum. For additional information regarding forward-looking statements, see "Forward-Looking Statements."

Overview of the Business

We are a clean energy company that owns and operates wind generation plants with an aggregate installed capacity of 239.2MW and is engaged in the generation of electricity business in northern Chile. We own and operate two wind farm projects: (i) the San Juan Project, a 193.2 MW facility located in Vallenar in the region of Atacama, currently the second largest wind farm project in the country, and (ii) the Totoral Project, a 46.0 MW facility located in Canela, in the region of Coquimbo. The San Juan Project has been fully operational since March 2017 and the Totoral Project has been fully operational since January 2010. Both wind projects are located in areas characterized for their strong and highly predictable wind resource, which is considered favorable for the development of wind farms utilizing Vestas.

Our main customers are highly-rated regulated DisCos (utility power distribution companies) and other large, experienced companies in varied industrial sectors (through long-term power purchase agreements (PPAs)), which provide a very stable source of recurring cash flow. As of March 31, 2021, 89.7% of our capacity at P50 is fully contracted under PPAs with tenors ranging from 4 to 12 years, and a weighted average life span of existing PPAs of 10.6 years, with DisCo PPAs expiring between 2031 and 2033. For the three-month period ending March 31, 2021, 86.9% of our revenue derived from sales of energy from PPAs, and over the fiscal years ended December 31, 2020, 2019 and 2018, 94.1%, 92.8% and 83.8% of our revenue derived from sales of energy from PPAs, respectively. Our most important individual PPA counterparty is Metro (Empresa de Transporte de Pasajeros Metro S.A., the operator of Santiago's subway system), a government-controlled entity rated A and A- by S&P and Fitch Ratings, respectively, representing 12.0% of our revenue for the three-month period ending March 31, 2021, and 13.1%, 27.9% and 24.8% for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively. The PPA with Metro expires in 2032. See "*Our Business—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*." We sell any excess energy to other power generation companies in the spot market. Spot market revenue represented in aggregate 13.1% of our revenue for the three-month period ending March 31, 2021, and 5.9%, 7.2% and 16.2%, for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively.

The Projects were refinanced in 2017 through a US$412 million issuance of secured bonds pursuant to the NPA with several investors. See "*—Liquidity and Capital Sources—NPA*" for an overview of the debt associated to the NPA.

Factors Affecting Our Results of Operations

Macroeconomic Conditions

Impact of COVID-19 Pandemic

Since the beginning of the COVID-19 pandemic in the first quarter of 2020, energy demand in the Chilean electricity market has decreased as a result of the pause, reduction or discontinuation of certain industrial and mining operations and limitations to local and international travel.

Beginning in March 2020, the Chilean government, the Central Bank and the CMF announced a series of measures aimed at mitigating the effects of COVID-19 on the Chilean economy. On April 2, 2020, the Central Bank published its monetary policy report for the month of March, modifying its GDP forecasts. The Central Bank estimated GDP contraction between 5.5% and 7.5% of GDP for 2020 and GDP growth between 4.75% and 6.25% for 2021 and between 3.0% and 4.0% for 2022. However, actual economic results may differ materially from these estimates.

The COVID-19 pandemic has mainly affected the Chilean electric system by decreasing demand, resulting in an overall rate growth of 0.2% in 2020 compared to 2019. Currently, there is an over capacity of regulated contracted energy due to a demand rate growth for 2020 below CNE's projections. According to the CNE's report dated April 2021, the oversupply level in 2020 was 38.7%, with the expectation that oversupply will decrease over time until it disappears in 2025. As a result of this oversupply, prices in the spot and PPAs markets have decreased in 2020.

Impact of Social Unrest – Social Agenda

Beginning in October 2019, Chile experienced a wave of protests and social unrest. These protests were initially sparked by the Chilean government's announcement of an increase in subway fares in Santiago but have since evolved to express broader concerns over inequality. These protests also affected the regular operation of the Santiago subway system (Metro, operator of the Santiago subway system, is one of our main PPA counterparties), which was the subject of violent attacks to cars and stations, and other disruptions. In response to these protests and related violence, the Chilean government suspended the increase in subway fares declared a state of emergency and imposed a nighttime curfew in the greater Santiago region and other cities, which were in place for nine days and ended on October 28, 2019.

Following consultations in the Chilean Congress with members of opposition parties, on October 22, 2019, the President announced a series of measures to address social demands (the "*Social Agenda*"), which included, among others, the reversal of a previously announced 9.2% price increase in regulated energy distribution tariffs and a temporary mechanism to stabilize such tariffs and defer price increases to distribution companies.

Together with the impact in electricity laws described below under "*—Impact of Changes in Electricity Laws – Tariff Stabilization Law and PEC*," social unrest affected consumption of electricity, in particular for medium and small companies, and affected traffic levels in the Santiago subway system, affecting demand under our existing PPA with Metro.

In addition, the Social Agenda incorporated a tax reform which included, among others, (a) the elimination of the attributed-income tax system and the consolidation of a single partially-integrated tax system for large companies, with a corporate tax rate of 27%, (b) the creation of a new special tax regime for small- and medium-sized companies, with a corporate tax rate of 25% that can be fully integrated with final taxes, (c) the gradual elimination of tax refunds that Chilean holding companies were able to claim for corporate taxes paid by their Chilean subsidiaries as a result of the absorption of holding companies' tax losses with dividends received from such subsidiaries, (d) an increase of the maximum tax bracket to 40% for the personal income tax applicable to resident individuals, (e) the application of Value Added Tax ("*VAT*") to foreign digital services that are used in Chile, and (f) stricter requirements for private investment funds to benefit from preferential tax treatment. This tax reform affected our results of operations because it reduced our ability to use Norvind's and San Juan's dividend tax credit against our accumulated losses. Likewise, since all of our revenue comes from the pass-through interest charge from intercompany debt between ILAP and each of Norvind and San Juan, these losses can no longer be used to derive a deferred revenue benefit.

Impact of Changes in Electricity Laws – Tariff Stabilization Law and PEC

As a result of the Social Agenda, on November 2, 2019, Chile enacted the Tariff Stabilization Law which stablished the Tariff Stabilization Mechanism for energy and power prices that Regulated Customers pay to DisCos by bringing forward the projected reduction in supply prices for the following years, meant to occur by the replacement of old (and more expensive) contracts by new (and cheaper) contracts that reflect the latest bids for CNE tenders of electricity.

The main purposes of the Tariff Stabilization Law are (i) to unwind the 9.2% electricity tariff increase which came into effect on October 10, 2019; and (ii) to avoid future increases on tariffs that Regulated Customers pay to

DisCos, temporarily stabilizing tariffs between July 1, 2019 and December 31, 2020 at the rates in effect on June 30, 2019. Tariffs applicable as of June 30, 2019 are known as the Regulated Customer stabilized price (*precio estabilizado a cliente regulado*), or PEC. In addition, the Tariff Stabilization Mechanism provides that the PEC may be adjusted only for inflation by the CPI from January 1, 2021, to December 31, 2024. The PEC so adjusted for inflation, is known as the Adjusted PEC. The cost of the Price Stabilization Mechanism will be borne by the generation companies because DisCos will pay the prices established by the rules issued by the CNE and not those prices previously agreed with the generation companies in PPAs currently in effect. Other contractual indexations such as U.S. CPI, exchange rate differences or fuel price changes are not considered in PEC adjustments. See "*Legal and Regulatory Framework—Tariff Stabilization Framework*."

The Tariff Stabilization Law has affected our results of operations since its enactment because DisCos have paid (and will pay) their suppliers the lower of (a) the PNLPs, or (b) the PECs or Adjusted PECs set out in each Tariff Decree. If, as a result of the Tariff Stabilization Mechanism, the PEC or Adjusted PEC applicable during a Tariff Period is lower than the PNLP that would otherwise have applied during that Tariff Period by a DisCo to a generating company under a PPA were the Tariff Stabilization Mechanism not in effect, the difference between that PEC or Adjusted PEC and that PNLP will constitute an unpaid balance (*saldo*), and the Ministry of Energy will be required to recognize it in the subsequent Tariff Decrees as a receivable, creating a PEC Receivable payable by that DisCo to that generating company. The Tariff Stabilization Mechanism will be in effect from July 1, 2019 until the earlier of (a) December 31, 2027, and (b) the date on which the PEC Receivables have been paid in full.

Impact of PEC Receivables

Generation companies must record monthly a difference between "original" indexed prices under the PPAs with DisCos and the stabilized prices. Receivables become irrevocable obligations of the DisCos when they are recognized by the Ministry of Energy in a Tariff Decree, and they are required under the Tariff Stabilization Law to be paid in full by December 31, 2027. See "*Legal and Regulatory Framework—Tariff Stabilization Framework—PEC Receivables*" for a description of the process of registration and payment of PEC Receivables.

As a general rule, differences to be collected as a result of the application of the Tariff Stabilization Law will not bear any interest. Exceptionally, amounts not collected from January 1, 2026, will bear interest equivalent to 6-month LIBOR (or the equivalent rate replacing it), plus a differential corresponding to the country risk.

ILAP PEC effects in results & statement of financial position			**Year**	
(in USD Thousands)	**March 31, 2021**	**2020**	**2019**	**2018**
Effects in Results:				
Revenue	**15,617**	**72,887**	**62,516**	**52,097**
Revenues (excluding PEC)	15,295	62,390	61,271	52,097
Deferred PEC Revenues Provision	322	10,497	1,245	-
Effects in the statement of financial position:				
Trade and other current receivables, non-current	**12,063**	**11,742**	**1,245**	**-**
Trade receivables non-current	12,063	11,742	1,245	-

As of December 31, 2020 and 2019, we recognized trade receivables non-current, which correspond to the PEC receivables, for an amount of US$11,742 thousand and US$1,245 thousand, respectively. According to the PEC mechanism described above and elsewhere in this offering memorandum, PEC Receivables are expected to be collected starting in 2023 and, consequently, are classified as non-current assets.

Revenues

For the three months ended March 31, 2021, and over the fiscal years ended December 31, 2020, 2019 and 2018, our total revenue was US$15.6 thousand, US$72.9 thousand, US$62.5 thousand, and US$52.1 thousand, respectively. Revenues from Contracted Customers represented 86.9%, 94.1%, 92.8% and 83.8%, for the three months ended March 31, 2021, and for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively, with revenues from spot market sales representing 13.1%, 5.9%, 7.2% and 16.2% for each of the same periods, respectively.

Revenues are obtained from the production and sale of power (electricity) and capacity and are recognized upon physical delivery. Capacity is an obligation for the delivery of energy when required by a customer. Our performance obligations are satisfied over time as the customer receives and consumes power. Accordingly, we recognize revenue for these contracts over time rather than at one point in time.

We render power and capacity supply services to Regulated Customers and Unregulated Customers. See "*Industry Overview—Business Segments*." Revenues from power sales to Regulated Customers (including DisCos) and Unregulated Customers (generally, industrial customers) are recorded on the basis of physical delivery of power and capacity, based mostly on long-term PPAs and some short-term PPAs. The sale of capacity is measured based on the availability of generation plants to provide power on an on-demand basis and do not depend on actual energy production. Revenue from PPAs is recognized using an exit method, since the power and capacity delivered best represents the transfer of goods or services to the customer.

We also generate revenues from sales of power and capacity in the spot market. These sales are recorded based on a physical delivery to other generating companies at the marginal cost of power and capacity. The spot market in Chile is organized through the National Electrical Coordinator in charge of balancing power and capacity surpluses and deficits. Energy and capacity surpluses are recorded as income and deficits are recorded as cost of sales in the income statement.

San Juan and Norvind have the right to issue certificates for energy production using NCREs (in Spanish, *Energía Renovable No Convencional*) for sale on the market. Revenues from these certificates are recorded when sold at the price established in contracts with third parties. As part of the sale of these certificates, for each of the years ending December 31, 2020, 2019 and 2018, we have generated revenues for US$50 thousand, US$25 thousand and US$45 thousand, respectively.

Factors Affecting the Level of Revenues

In general, our revenue is affected by a combination of factors, including low/high generation, oversupply in the market and high wind availability.

San Juan Project

The following table shows certain operational metrics in connection with the San Juan Project, for the periods indicated below.

	March 31, 2021	**2020**	**2019**	**2018**
Production (MWh)	114.4	522.8	579.4	553.3
Availability	93.3%	95.3%	97.0%	97.4%
Capacity Factors	27.4%	30.8%	34.5%	34.2%
Curtailment Losses	-	2.5%	3.6%	10.3%

During years 2018 and 2019 a delay in the construction in the Cardones-Polpaico 500kV transmission line caused a major curtailment of our capacity at the San Juan Project. Construction of this new transmission line was completed in June 2019.

During 2020, a non-programed stoppage in one of the two circuits that interconnect the San Juan Project to the main grid reduced its capacity to 50% for 36 straight days due to a zigzag transformer (a protection system for the main transformers) overheat, which required us to decrease our operations as a precautionary measure until we bought and installed a new zigzag transformer and reconfigured the MV cables of the power transformer.

Totoral Project

The following table shows certain operational metrics in connection with the Totoral Project, for the periods indicated below.

	March 31, 2021	2020	2019	2018
Production (MWh)	14.9	79.0	83.2	81.5
Availability	97.2%	97.3%	96.6%	96.9%
Capacity Factors	15.1%	19.6%	20.7%	20.2%
Curtailment Losses	-	3.3%	4.8%	10.0%

The Totoral Project suffered the same curtailment issues during 2018 and 2019, described above with respect to the San Juan Project.

Revenue from Contracted Customers

We earn contracted revenues from our PPAs with Contracted Customers, mainly DisCos. These PPAs build in a financial margin for the purchase and sale of power and capacity. For the three months ended March 31, 2021, revenues from PPAs with Contracted Customers represented US$13,575 thousand, compared to US$19,487 thousand for the three months ended March 31, 2020. This decrease in revenues is largely driven by Enel Generación's PPA, which has had no consumption during 2021. Also, during the three months ended March 31, 2020, we recognized US$3.1 million in PEC revenues, in both energy and power sales from previous fiscal periods, in accordance with the first definitive nodal price report issued by the CNE that included accumulated PEC balances from 2019. This resulted in a recognition of amounts that were higher than the provisioned amount calculated by us in 2019 using conservative assumptions and in increased revenues for 2020.

For the year ended December 31, 2020, revenue from PPAs with Contracted Customers represented US$68,623 thousand of total revenue, compared to US$58,017 thousand for the year ended December 31, 2019. The increase in revenues between 2020 and 2019 is largely driven by an increase in DisCos consumption (20 GWh of higher consumption) and accounting of PEC revenues of 2019 in 2020 (energy and power). For the year ended December 31, 2018, revenues from PPAs with Contracted Customers represented US$43,644 thousand. The increase in revenues between 2019 and 2018 is largely driven by the entry into effect of several PPAs with DisCos awarded in 2017, higher levels of consumption by DisCos (93 GWh of higher consumption), the increase of consumption under the PPA with Enel Generación (57 GWh of higher consumption), and sale of energy to Pacific Hydro Chacayes under our energy hedge contract (35 GWh).

Spot Market Revenue

We also earn energy revenue on sales of energy in the spot market. For the three months ended March 31, 2021, revenues from spot market sales represented US$2,042 thousand, compared to US$1,433 thousand for the three months ended March 31, 2020. This increase in revenues is largely driven by Enel Generación's lower consumption levels during 2021, which resulted in a larger portion of the energy generated being sold on the spot market. For each of the years ended December 31, 2020 and 2019, revenue from spot market sales represented US$4,264 thousand and US$4,499 thousand, respectively. The decrease in spot market sales between 2020 and 2019 is largely driven by an increase in the energy sold under PPAs. For the year ended December 31, 2018, revenue from spot market sales was US$8,453 thousand. The decrease in spot market sales between 2019 and 2018 is largely driven by an increase in consumption by Enel Distribución from the San Juan Project and the entry into effect of several DisCos contracts awarded in 2017.

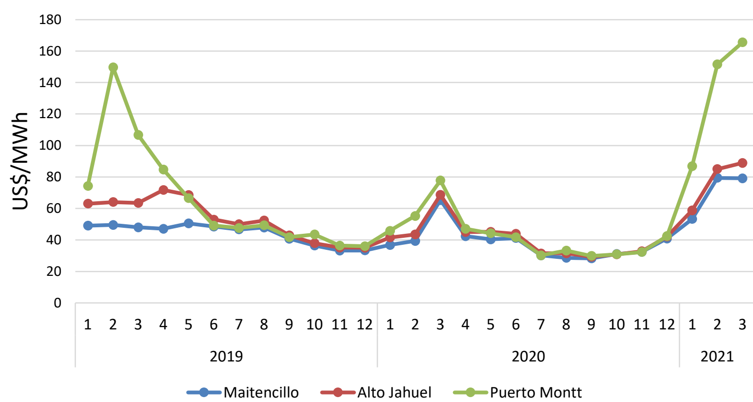
Oversupply Conditions

The COVID-19 pandemic has created oversupply in the energy generation industry as a result of many production and industry activities being suspended, postponed or reduced. See "*Risk Factors—Oversupply conditions* *may affect our profitability and results of operations*." Currently, the regulated contracted energy is higher than the regulated consumed energy due to the regulated demand rate growth below the level projected by CNE for the auction processes. According to the information contained in the Preliminary CNE's report dated April 2021, the calculated oversupply level in 2020 was 38.7%, with oversupply progressively decreasing by 2025. Consequently, the CNE modified the 2019/01 regulated auction process in order to move the supply start year from 2024 to 2026, and modified the schedule of the auction and the contracted energy level in a new process named 2021/01.

Volatility Conditions During the three months ended March 31, 2021

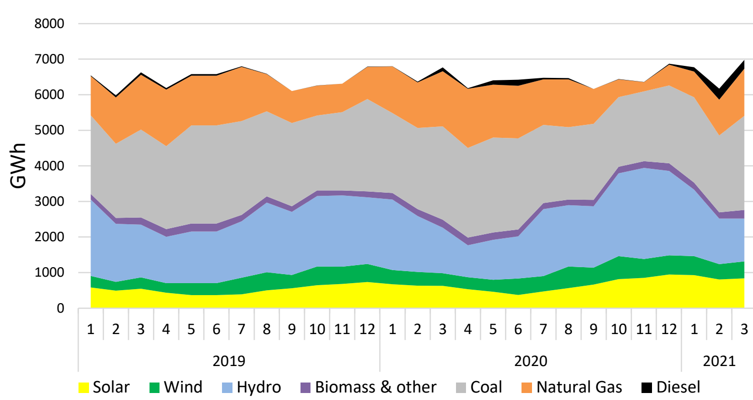
During the three months ended March 31, 2021, we were affected by an increase in marginal costs caused and unusual high volatility conditions in the energy market caused low levels of hydro generation levels, mainly driven by extreme drought conditions in Chile, and low levels of natural gas production. This resulted in high volatility in spot market prices, and consequently, in us buying energy in the spot market at prices higher than usual during hours where were the Projects were not producing energy in order to satisfy our energy delivery requirements under our PPAs.

Marginal costs during the three months ended March 31, 2021, increased in comparison with the prices registered during the same period in 2020, as shown in the following figure.



Source: National Electrical Coordinator.

At center and north interconnection nodes (Maitencillo and Alto Jahuel), marginal costs increased during the three months ended March 31, 2021, by approximately 50% compared to the same period in 2020, which was caused by the reduction of hydro and natural gas generation levels, as shown in the following figure, which depicts the monthly generation levels by source:



Source: National Electrical Coordinator.

Hydro generation levels have been trending downwards during the first three months of every year for the last few years, showing a decrease in production levels of approximately 8%, for first three months ended March 31, 2020 compared to the same period in 2019, and 10%, for first three months ended March 31, 2021 compared to the same period in 2020. Similarly, natural gas generation showed a decrease in production levels of approximately 26% for first three months ended March 31, 2021, compared to the same periods in 2020 and 2019. These hydro and natural gas generation reductions led to the dispatch of diesel units in order to supply demand in the spot market, which registered variable costs equal to US$/MWh 165.5 during the three months ended March 31, 2021.

Marginal costs during the three months ended March 31, 2021, were also affected by the differences of energy prices in the spot market between day time and night time, producing differences in the marginal costs of the north and center nodes, as for instance occurred in March 2021 between Crucero node (US$75.7 MWh) and Alto Jahuel (US$88.8 MWh), mainly caused by congestions at transmission systems during sun hours.

Finally, the marginal costs at southern node (Puerto Montt) have been decoupled during the first three months ended March 31, 2019 and 2021. During that period in 2021, the marginal costs at southern area relied upon the Canutillar hydro plant (170 MW), which registered very low flows levels due to general dry conditions during summer months and was not able to operate in order to manage its water reservoir. As a result, demand in this area was supplied by diesel units, which became the main generation source during the three months ended March 31, 2021.

Cost of Sales

Our cost of sales at each Project level consists of fees paid in connection with the use of the transmission system, maintenance, municipal taxes and fees, depreciation, insurance and others.

Transmission system costs mainly relate to the use of the central transmission system and the payment of tolls related to that service.

Maintenance costs consist mainly in the O&M Agreements with Vestas for both Projects.

Municipal taxes and fees consist of payments made to local municipalities in Canela and Freirina, mainly with respect to commercial patents.

Depreciation and amortization consist mainly of the depreciation of assets in our wind farms.

Insurance costs consist of the cost of our insurance premiums, mainly in connection with O&M risk.

Other costs consist mainly of coordination costs with National Electrical Coordinator and other intercompany costs.

Administrative Expenses

We incur administrative expenses at each Project level mainly consisting of depreciation and amortization expenses, consulting expenses, expenses from back office services (salaries and benefits paid to operating staff), and other expenses.

Consulting expenses relate mainly to lawyers' fees, energy consulting fees, the cost of pricing studies and the price of O&M studies.

Financial Expenses

Our financial expenses mainly relate to interest payments in connection with the NPA.

Interest payments in connection with the NPA totaled US$10,566 thousand and US$10,843 thousand for the three months ended March 31, 2021 and 2020, and US$21,572 thousand, US$21,954 thousand and US$22,027 thousand for each of the years ended December 31, 2020, 2019 and 2018, respectively. The decrease between the years ended December 31, 2020 and 2019 was due mainly to a lower level of interest paid following the payment of principal in accordance with the amortization schedule under the NPA. The decrease between the years ended December 31, 2019 and 2018 was due mainly to a lower level of interest payments as set forth above.

Impairment Charges

For the year ended December 31, 2019, we recognized an impairment charge of US$4,665 thousand on the goodwill associated with Norvind. For a full description of this charge, see Note 8 to our Audited Consolidated Financial Statements included elsewhere in this offering memorandum.

Results of Operations

Three months ended March 31, 2021 compared to three months ended March 31, 2020

The following table shows our consolidated results of operations for the three months ended March 31, 2021 and the three months ended March 31, 2020:

	For the three months ended March 31,		**Variation**
	2021	**2020**	**(%)**
	(in thousands of US$)		
Revenue Contracted Customers	13,575	19,487	(30.3)
Revenue Spot Market	2,042	1,433	42.5
Revenue	**15,617**	**20,920**	**(25.3)**
Cost of Sales	(14,918)	(16,637)	(10.3)
Gross profit	**699**	**4,283**	**(83.7)**
Administrative expenses	(458)	(430)	6.5
Operating profit	**241**	**3,853**	**(93.7)**
Financial income	0.1	15	(99.3)
Financial expenses	(6,263)	(6,425)	(2.5)
Foreign exchange differences	(415)	(789)	(47.4)
Impairment charges	-	-	-
Loss before taxes	**(6,437)**	**(3,346)**	**(92.4)**
Income tax benefit (expense)	1,693	(524)	-
Loss for the period	**(4,744)**	**(3,870)**	**(22.6)**

Revenue

Revenue decreased by 25.3% to US$15,617 thousand for the three months ended March 31, 2021 from US$20,920 thousand for the same period in 2020 for the reasons discussed below.

Revenue from Contracted Customers. Revenue from Contracted Customers decreased by 30.3% to US$13,575 thousand for the three months ended March 31, 2021 from US$19,487 thousand for the same period in 2020, primarily as a result of Enel Generación's PPA, which registered no consumption during 2021. Also, during the three months ended March 31, 2020, we recognized US$3.1 million recognition in PEC revenues as described above.

Revenue from Spot Market Sales. Revenue from Spot Market sales increased by 42.5% to US$2,042 thousand for the three months ended March 31, 2021 from US$1,433 thousand for the same period in 2020, primarily as a result of high volatility in spot price market, resulting in higher cost of energy in order to satisfy our energy delivery requirements under our PPAs in hours where the Projects were not producing energy, as described above.

Cost of Sales

Cost of sales decreased by 10.3% to US$14,918 thousand for the three months ended March 31, 2021 from US$16,637 thousand for the same period in 2020, primarily because we did not need to purchase as much energy in the spot market in the three months ended March 31, 2021 to satisfy our obligations of energy delivery under our PPAs because we produced more power and DisCos consumed during this period.

Transmission Costs. Use of transmission system expenses decreased by 1.6% to US$1,595 thousand for the three months ended March 31, 2021 from US$1,621 thousand for the same period in 2020, primarily as a result of a decrease in the amount of national transmission tolls following amendments to the Transmission Law.

Maintenance. Maintenance expenses increased by 12.3% to US$1,294 thousand for the three months ended March 31, 2021 from US$1,152 thousand for the same period in 2020, primarily as a result of the indexation of the O&M Agreements with Vestas for both of our Projects.

Municipal Tax. Municipal tax expenses decreased by 52.2% to US$11 thousand for the three months ended March 31, 2021 from US$23 thousand for the same period in 2020, primarily as a result of a decrease in the tax basis, which is the basis for the calculation of this cost.

Depreciation and amortization. Depreciation and amortization decreased by 7.4% to US$5,304 thousand for the three months ended March 31, 2021 from US$5,728 thousand for the same period in 2020, primarily as a result of an amortization of impairment reserves made during 2020, which has not been made since 2016.

Insurance. Insurance expenses increased by 48.3% to US$264 thousand for the three months ended March 31, 2021 from US$178 thousand for the same period in 2020, primarily as a result of a general increase in the insurance market prices.

Other costs and expenses. Other costs and expenses decreased by 9.2% to US$178 thousand for the three months ended March 31, 2021 from US$196 thousand for the same period in 2020, mainly driven by a reclassification of capital expenses for physical assets that was made during 2020.

Administrative Expenses

Administrative expenses increased by 6.5% to US$458 thousand for the three months ended March 31, 2021 from US$430 thousand for the same period in 2020, primarily as a result of indexation of an intercompany services agreement, whereby LAP Chile charges a service fee to ILAP.

Financial Income

Financial income decreased by 99.3% to US$0.1 thousand for the three months ended March 31, 2021 from US$15 thousand for the same period in 2020, primarily as a result of lower availability of cash for investment during the three months ended March 31, 2021 and lower interest rates on invested assets.

Financial Expenses

Financial expenses decreased by 2.5% to US$6,263 thousand for the three months ended March 31, 2021 from US$6,425 thousand for the same period in 2020, primarily as a result of a lower interest payments in accordance with the terms of the NPA.

Foreign Exchange Differences

Net foreign exchange losses decreased by 47.4% to US$415 thousand for the three months ended March 31, 2021 from US$789 thousand for the same period in 2020, primarily as a result of changes in the exchange rate, affecting accounts receivable and payable in Pesos.

Income Tax Benefit/(Expense)

We recorded income tax benefit of US$1,693 thousand for the three months ended March 31, 2021 as compared to US$524 thousand expense for the same period in 2020, primarily as a result of a review by the SII at Norvind, that decreased the accumulated losses, generating a tax expense for the period.

Net Loss

Net loss increased by 22.6% to US$4,744 thousand for the three months ended March 31, 2021 from US$3,870 thousand for the same period in 2020 for the reasons discussed above.

Year ended December 31, 2020 compared to year ended December 31, 2019

The following table shows our consolidated results of operations for the period from the year ended December 31, 2020 and the year ended December 31, 2019:

	For the year ended December 31,		Variation
	2020	**2019**	**(%)**
	(in thousands of US$)		
Revenue Contracted Customers	68,623	58,017	18.3
Revenue Spot Market	4,264	4,499	(5.2)
Revenue	**72,887**	**62,516**	**16.6**
Cost of Sales	(55,477)	(50,540)	9.8
Gross profit	**17,410**	**11,976**	**45.4**
Administrative expenses	(2,836)	(2,287)	24.0
Operating profit	**14,574**	**9,689**	**50.4**
Financial income	16	216	(92.6)
Financial expenses	(25,279)	(25,730)	(1.8)
Foreign exchange differences	(82)	48	(270.8)
Impairment charges	-	(4,665)	(100.0)
Loss before taxes	**(10,771)**	**(20,442)**	**(47.3)**
Income tax benefit	1,182	1,312	(9.9)
Loss for the year	**(9,589)**	**(19,130)**	**(49.9)**

Revenue

Revenue increased by 16.6% to US$72,887 thousand for the year ended December 31, 2020 from US$62,516 thousand for the same period in 2019, primarily as a result of an increase in consumption from Contracted Customers.

Revenue from Contracted Customers. Revenue from Contracted Customers increased by 18.3% to US$68,623 thousand for the year ended December 31, 2020 from US$58,017 thousand for the same period in 2019, primarily as a result of lower oversupply and higher amount of energy consumed by our Contracted Customers.

Revenue from Spot Market Sales. Revenue from spot market sales decreased by 5.2% to US$4,264 thousand for the year ended December 31, 2020 from US$4,499 thousand for the same period in 2019, primarily as a result of a higher consumption level by our Contracted Customers (thereby decreasing the energy available for spot market sales) and a decrease in spot prices.

Cost of Sales

Cost of sales increased by 9.8% to US$55,477 thousand for the year ended December 31, 2020 from US$50,540 thousand for the same period in 2019, primarily as a result of higher energy consumption in connection with the Enel Generación's PPA, and lower generation levels by the San Juan Project (especially at times of high energy demand), which required us to purchase energy in the spot market to satisfy our PPA obligations during 2020.

Transmission Costs. Use of transmission system expenses decreased by 2.4% to US$6,712 thousand for the year ended December 31, 2020 from US$6,874 thousand for the same period in 2019, primarily as a result of a decrease in the amount of national transmission tolls following amendments to the Transmission Law.

Maintenance. Maintenance expenses increased by 15.3% to US$5,364 thousand for the year ended December 31, 2020 from US$4,651 thousand for the same period in 2019, primarily as a result of an incorrect invoice under the Vestas O&M Agreements during 2020 in an amount of US$120 thousand that will be refunded to us by a lower contract rate during 2021. In addition, there was also a higher expense due to insurance deductibles for losses in the San Juan Project related to the zigzag transformer.

Municipal Tax. Municipal tax expenses decreased by 51.5% to US$33 thousand for the year ended December 31, 2020 from US$68 thousand for the same period in 2019, primarily as a result of a decrease in the tax adjusted equity, which is the basis for the calculation of this cost.

Depreciation and amortization. Depreciation and amortization decreased by 7.6% to US$21,280 thousand for the year ended December 31, 2020 from US$23,034 thousand for the same period in 2019, primarily as a result of lower depreciation due to impairment of fixed assets in 2013 generating lower financial basis of assets to be depreciated.

Insurance. Insurance expenses increased by 4.1% to US$944 thousand for the year ended December 31, 2020 from US$907 thousand for the same period in 2019, primarily as a result of a general increase of premium prices in the insurance market.

Other costs and expenses. Other costs and expenses decreased by 34.4% to US$827 thousand for the year ended December 31, 2020 from US$1,260 thousand for the same period in 2019, mainly driven by the decrease of regulatory costs and studies.

Administrative Expenses

Administrative expenses increased by 24.0% to US$2,836 thousand for the year ended December 31, 2020 from US$2,287 thousand for the same period in 2019, primarily as a result of hiring professional consultant services such as lawyers, energy consultants, pricing experts and O&M engineers, mainly related to the new stabilization price system (PEC) and other price studies, together with indexing other service contracts.

Financial Income

Financial income decreased by 92.6% to US$16 thousand for the year ended December 31, 2020 from US$216 thousand for the same period in 2019, primarily as a result of a recovery of claims in the San Juan Project in 2019 and the interest generated on time deposits.

Financial Expenses

Financial expenses decreased by 1.8% to US$25,279 thousand for the year ended December 31, 2020 from US$25,730 thousand for the same period in 2019, primarily as a result of a lower level of interest payments in accordance with the terms of the NPA.

Foreign Exchange Differences

We recorded net foreign exchange loss of US$82 thousand for the year ended December 31, 2020 as compared to net foreign exchange gain of US$48 thousand for the year 2019, primarily as a result of changes in the exchange rate in accounts receivable and payable in Pesos.

Impairment Charges

For the year ended December 31, 2019, Norvind incurred we recorded an impairment charge of US$4,665 thousand on the Norvind goodwill. There were no impairment charges for the year ended December 31, 2020.

Income Tax Benefit

Income tax benefit decreased by 9.9% to US$1,182 thousand for the year ended December 31, 2020 from US$1,312 thousand for the year 2019, primarily as a result of a lower loss before taxes in 2020.

Net Loss

Net loss decreased by 49.9% to US$9,589 thousand for the year ended December 31, 2020 from US$19,130 thousand for the same period in 2019 for the reasons discussed above.

Year ended December 31, 2019 compared to year ended December 31, 2018

	For the year ended December 31,		Variation
	2019	2018	(%)
	(in thousands of US$)		
Revenue Contracted Customers	58,017	43,644	32.9
Revenue Spot Market	4,499	8,453	(46.8)
Revenue	**62,516**	**52,097**	**20.0**
Cost of Sales	(50,540)	(44,644)	13.2
Gross profit	**11,976**	**7,453**	**60.7**
Administrative expenses	(2,287)	(2,416)	(5.3)
Operating profit	**9,689**	**5,037**	**92.4**
Financial income	216	219	(1.4)
Financial expenses	(25,730)	(25,504)	0.9
Foreign exchange differences	48	(171)	128.1
Impairment charges	(4,665)	-	-
Loss before taxes	**(20,442)**	**(20,419)**	**0.1**
Income tax benefit	1,312	5,515	(76.2)
Loss for the year	**(19,130)**	**(14,904)**	**28.4**

Revenue

Revenue increased by 20.0% to US$62,516 thousand for the year ended December 31, 2019 from US$52,097 thousand for the same period in 2018, primarily as a result of an increase in the energy consumed by our Contracted Customers for both Projects.

Revenue from Contracted Customers. Revenue from Contracted Customers increased by 32.9% to US$58,017 thousand for the year ended December 31, 2019 from US$43,644 thousand for the same period in 2018, primarily as a result of an increase in the energy consumed by our Contracted Customers, mainly DisCos, for both Projects at prices beneficial to us.

Revenue from Spot Market Sales. Revenue from Spot Market sales decreased by 46.8% to US$4,499 thousand for the year ended December 31, 2019 from US$8,453 thousand for the same period in 2018, primarily as a result of a higher levels of energy contracted with our Contracted Customers and a drop in the spot market prices.

Cost of Sales

Cost of sales increased by 13.2% to US$50,540 thousand for the year ended December 31, 2019 from US$44,644 thousand for the same period in 2018, primarily as a result of increased levels of energy purchases from Pacific Hydro Chacayes under an energy hedge contract, and the need to purchase power in the open market in order to satisfy our current obligations due to increased PPA sales.

Transmission Costs. Use of transmission system expenses increased by 25.8% to US$6,874 thousand for the year ended December 31, 2019 from US$5,463 thousand for the same period in 2018, primarily as a result of a new regulation in the tariff revenue collection system, charging a cost for the total energy contracted through PPAs and not for the energy actually injected. This change particularly affected San Juan, due to its PPA with Metro.

Maintenance. Maintenance expenses decreased by 0.5% to US$4,651 thousand for the year ended December 31, 2019 from US$4,676 thousand for the same period in 2018.

Municipal Tax. Municipal tax expenses decreased by 69.6% to US$68 thousand for the year ended December 31, 2019 from US$224 thousand for the same period in 2018, primarily as a result of a decrease in the tax adjusted equity, which is the basis for the calculation of this cost.

Depreciation and amortization. Depreciation and amortization increased by 2.6% to US$23,034 thousand for the year ended December 31, 2019 from US$22,448 thousand for the same period in 2018, primarily as a result of the amortization of right-of-use assets with respect to the San Juan Project as required by IFRS 16.

Insurance. Insurance expenses increased by 5.8% to US$907 thousand for the year ended December 31, 2019 from US$857 thousand for the same period in 2018, primarily as a result of a general increase of premiums in the insurance market.

Other costs and expenses. Other costs and expenses increased by 10.4% to US$1,260 thousand for the year ended December 31, 2019 from US$1,141 thousand for the same period in 2018, mainly driven by higher regulatory costs and studies.

Administrative Expenses

Administrative expenses decreased by 5.3% to US$2,287 thousand for the year ended December 31, 2019 from US$2,416 thousand for the same period in 2018, primarily as a result of the indexation of O&M Agreements with Vestas.

Financial Income

Financial income decreased by 1.4% to US$216 thousand for the year ended December 31, 2019 from US$219 thousand for the same period in 2018, primarily as a result of a decrease in claim recoveries and interest differences on time deposits.

Financial Expenses

Financial expenses increased by 0.9% to US$25,730 thousand for the year ended December 31, 2019 from US$25,504 thousand for the same period in 2018, primarily as a result of the implementation of IFRS 16 during 2018, under which an expense of interest on lease liabilities related to our land lease contract was added as a financial expense.

Foreign Exchange Differences

We recorded net foreign exchange gain of US$48 thousand for the year ended December 31, 2019 comparing to net foreign exchange loss of US$171 thousand for the year 2018, primarily as a result of changes in the exchange rate, affecting accounts receivable and payable in Pesos.

Impairment Charges

For the year ended December 31, 2019, we recorded an impairment charge of US$4,665 thousand on the Norvind goodwill. There were no impairment charges for the year ended December 31, 2018.

Income Tax Benefit/(Expense)

Income tax benefit decreased by 76.2% to US$1,312 thousand for the year ended December 31, 2019 from US$5,515 thousand for the year 2018, primarily as a result of a derecognition of deferred tax asset from tax losses of ILAP.

Net Loss

Net loss increased by 28.3% to US$19,130 thousand for the year ended December 31, 2019 from US$14,904 thousand for the same period in 2018, primarily for the reasons described above.

Cash Flows

Three months ended March 31, 2021 compared to three months ended March 31, 2020

	Three months ended March 31, 2021	2020
	(in thousands of US$)	
Net cash flow generated by (used in) operating activities	1,091	(6,377)
Net cash flow generated by (used in) investing activities	-	(14)
Net cash flow generated by (used in) financing activities	(5,815)	(4,345)
Net increase (decrease) of cash and cash equivalents	(4,724)	(10,736)
Cash and cash equivalents, opening balance	**7,363**	**18,428**
Cash and cash equivalents, closing balance	**2,639**	**7,692**

Net cash flow generated by (used in) operating activities

Net cash flow generated by operating activities for the three months ended March 31, 2021 was US$1,091 thousand, as compared to net cash flow used in operating activities of US$(6,377) thousand for the three months ended March 31, 2020. This increase was primarily due to the recognition of higher income from PEC accounts recorded during 2020 carried forward from previous results, which do not represent cash inflows for the period.

Net cash flow generated by (used in) investing activities

Net cash used in investing activities for the three months ended March 31, 2021 was US$0 thousand, as compared to net cash used in investing activities of US$(14) thousand for the three months ended March 31, 2020. This difference was primarily due to certain PPE investments made during the three months ended March 31, 2020.

Net cash flow generated by (used in) financing activities

Net cash used in financing activities for the three months ended March 31, 2021 was US$5,815 thousand compared to net cash used in financing activities of US$4,345 thousand for the three months ended March 31, 2020. This increase was primarily due to a higher level of debt payments in accordance with the amortization schedule under the NPA.

The decrease in cash and cash equivalents at the closing balance as at March 31, 2021, compared to March 31, 2020, was mainly due to the accumulation in PEC Receivables during 2021.

Year ended December 31, 2020 compared to year ended December 31, 2019

	For the year ended December 31, 2020	2019
	(in thousands of US$)	
Net cash flow generated by (used in) operating activities	2,919	7,875
Net cash flow generated by (used in) investing activities	(74)	3,438
Net cash flow generated by (used in) financing activities	(13,910)	(6,198)
Net increase (decrease) of cash and cash equivalents	(11,065)	5,115
Cash and cash equivalents, opening balance	**18,428**	**13,313**
Cash and cash equivalents, closing balance	**7,363**	**18,428**

Net cash flow generated by (used in) operating activities

Net cash flow generated by operating activities for the year ended December 31, 2020 was US$2,919 thousand, and US$7,875 thousand for the year ended December 31, 2019. This decrease was primarily due to trade accounts receivables generated by PEC revenues in 2020.

Net cash flow generated by (used in) investing activities

Net cash used in investing activities for the year ended December 31, 2020 was US$74 thousand comparing to the net cash generated of US$3,438 thousand for the year ended December 31, 2019. This decrease was primarily due to the receipt during 2019 of term deposits for USD3,526 thousand that was invested during 2018 due to an excess of cash.

Net cash flow generated by (used in) financing activities

Net cash used in financing activities for the year ended December 31, 2020 was US$13,910 thousand and US$6,198 thousand for the year ended December 31, 2019. This increase was primarily due to higher amounts of debt service during 2020.

Year ended December 31, 2019 compared to year ended December 31, 2018

	For the year ended December 31, 2019	2018
	(in thousands of US$)	
Net cash flow generated by (used in) operating activities	7,875	8,203
Net cash flow generated by (used in) investing activities	3,438	(4,456)
Net cash flow generated by (used in) financing activities	(6,198)	(25,404)
Net increase (decrease) of cash and cash equivalents	5,115	(21,657)
Cash and cash equivalents, opening balance	**13,313**	**34,970**
Cash and cash equivalents, closing balance	**18,428**	**13,313**

Net cash flow generated by (used in) operating activities

Net cash flow generated by operating activities was US$7,875 thousand for the year ended December 31, 2019 and US$8,203 thousand for the year ended December 31, 2018. This decrease was primarily due to the PEC Law enacted during 2019, resulting in a portion of that year's revenues not generating cash flows.

Net cash flow generated by (used in) investing activities

Net cash generated by investing activities was US$3,438 thousand for the year ended December 31, 2019 comparing to net cash used of US$4,456 thousand for the year ended December 31, 2018. This variation was primarily due to an investment in term deposits during 2018 from excess cash that were redeemed during 2019.

Net cash flow generated by (used in) financing activities

Net cash used in financing activities was US$6,198 thousand for the year ended December 31, 2019 and US$25,404 thousand for the year ended December 31, 2019. This decrease was primarily due to a capital reduction during 2018 of US$24,603 thousand.

Liquidity and Capital Resources

We presently finance and have financed most of our major capital and liquidity needs through proceeds from debt financings, cash from flow generated from operating activities and equity contributions. These have been used to fund the refinancing of debt incurred in connection with the construction of the Projects, pay operational costs and expenses and pay debt service under the NPA.

Following the issuance of the Notes, our most important source of cash will come from the Notes and cash generated from operating activities. We expect to apply the net proceeds from the sale of the Notes, together with existing cash held by us, to repay all outstanding principal under the NPA, plus, accrued interest, breakage costs (if applicable), premiums and/or fees and expenses (if applicable) in respect of such NPA up to the Issue Date, and pay certain fees and expenses related to the offering of the Notes. See "*Use of Proceeds*."

NPA

In September 2017, we entered into an agreement with private investors for the issuance of a US$412,000 thousand bond to refinance the existing debt in connection with the construction of the San Juan Project and the Totoral Project, associated break costs, provide funding for reserve accounts, pay fees, expenses, make distribution to our owners and for general corporate purposes. The bonds issued under the NPA bear a fixed interest rate of 5.35% *per annum*, and mature in March 2033. The NPA contains restrictions on incurrence of debt, pledge of assets, dividends and distributions, transfer of property, change of control, among others. The obligations under the NPA are secured by the assets of San Juan and Norvind, the contractual and collection rights under the PPAs, certain transaction accounts in Chile and the U.S., and the shares in each of ILAP, San Juan and Norvind.

The outstanding amount under the NPA as of March 31, 2021, is US$389,235 thousand. As of the date of this offering memorandum, we have been in compliance with the covenants and obligations under the NPA. It is expected that the obligations under the NPA will be fully repaid with the proceeds of the issuance of the Notes. See "*Use of Proceeds*."

Capital Expenditures

We have not incurred in material capital expenditures in the Projects during the periods described above.

Contractual Obligations

Other than the indebtedness related to the NPA, which we expect it will repaid on the Issue Date with the proceeds of the Notes, as of March 31, 2021, we do not have material contractual obligations (not including other common non-contractual obligations, such as pension obligations and deferred tax liabilities).

Related Party Transactions

We record accounts receivable and payable from related entities for services rendered, at market conditions, with terms similar to those which usually prevail in the open market between independent parties. These services are included in our normal commercial business and are typically in connection with general management, back office and administrative services. See "*Related Party Transactions—Service Agreements*." Starting on the Issue Date, we will be restricted from entering into certain transactions with affiliates. See "*Description of the Notes—Transactions with Affiliates*."

Financial Risks

We are exposed to credit risk, liquidity risk and market risk. Our overall risk management is mainly focused on the unpredictability of financial markets and seeks to minimize potential adverse effects on our financial performance. Senior management is responsible for establishing and supervising our risk management structure, and developing and monitoring risk management policies. Our risk management policies are established in order to identify and analyze risks we face in the ordinary course, set appropriate limits and risk controls, and monitor risks and the compliance limits. Policies and risk management systems are reviewed regularly in order to reflect changes in market conditions and our activities. Through our management procedures and regulations, we have developed a constructive and disciplined control environment in which all employees understand their roles and obligations.

Credit Risk

We are exposed to concentrations of credit risk, primarily with respect to our bank deposits, and to a lesser extent, trade accounts receivable from our clients in connection with our power generation activities. Our cash management policy is to invest in investment-grade institutions only and only within the short term. Trade accounts receivable, current and non-current, correspond to companies in the electric sector, in both the regulated and unregulated market. In our ordinary electricity generation business, we deal mostly with financially strong creditworthy counterparties, which have historically exhibited a positive payment record and report low level of credit risk. The stock of accounts receivables generated in the normal course of business is characterized by the short-term nature of the collection process. Applicable laws and regulations establish deadlines for the invoicing and payment of such accounts receivable. The weighted average commercial collection period for approximately 96.2% of the total monthly revenues is 15 days, with respect to the San Juan Project, and the weighted average commercial collection period for approximately 95.8% of the total monthly revenues is 15 days, with respect to the Totoral Project. There is no evidence of material impairment on these assets.

Liquidity Risk

We are exposed to the risk of satisfying our financial liabilities that are settled by delivering cash or other financial assets. Management supervises cash flow projections made over our liquidity requirements in order to ensure that there is sufficient cash to meet operational needs while maintaining enough margin for unused lines of credit and pay debt service under the NPA, without incurring in unacceptable losses or risking our reputation.

Market Risk

We are exposed to the risk of changes in energy prices, exchange rates and interest rates. We manage and control exposure to these risks within acceptable parameters, while optimizing return.

Energy Prices

Since 2019, our commercial strategy has been aimed at minimizing the risk of exposure to the spot market and its inherent price volatility. In this context, we have signed mid- and long-term PPAs to achieve a contracted energy commitment equal to the P90 annual expected generation. Consequently, we have entered into new PPAs for the available energy remaining as a result of the DisCos' oversupply with 16 diversified Unregulated Customers, of which PPAs, approximately 318 GWh-year have been and will become effective between 2019 and 2021. These PPAs, together with our previous ones, resulted in less than 10% of our production being sold on the spot market, minimizing the risk of volatility and ensuring steady income for the subsequent four years, which has allowed us to focus on optimizing our operations.

Exchange Rate Risk

We are exposed to currency risk as some of our transactions and the related balances of monetary assets and liabilities are denominated in in Chilean Pesos and not in U.S. Dollar (our functional currency). We consider that currency risk is not significant. For the three-month period ending March 31, 2021, 86.9% of our revenue derived from sales of energy from PPAs, and over the fiscal years ended December 31, 2020, 2019 and 2018, 94.1%, 92.8% and 83.8% of our revenue derived from sales of energy from PPAs, respectively. Correspondingly, our long-term debt corresponding to the obligations under the NPA are denominated U.S. Dollars, while some of our Chilean Peso-denominated revenues have short collection and payment periods.

Interest Rate Risk

We are not exposed to interest rate risk because our long-term debt corresponding to the obligations under the NPA has a fixed rate of 5.35% *per annum*, and deposits with banks have a very short maturity period.

Hedging Arrangements

As of the date of this offering memorandum, we do not maintain any hedging arrangements.

Off-Balance Sheet Arrangements

As of the date of this offering memorandum, we do not maintain any off-balance sheet arrangements.

Significant Accounting Policies

We have identified certain significant accounting policies on which our financial condition and results of operations are dependent. These significant accounting policies most often involve complex quantitative analyses or are based on subjective judgments or decisions. A change in these estimates and assumptions could affect the value of our assets, liabilities, shareholders' equity and earnings, as well as our contingent assets and liabilities. For a full description of these accounting policies, see Note 2 to our Audited Consolidated Financial Statements included elsewhere in this offering memorandum.

Critical Accounting Estimates

In preparing the consolidated financial statements, certain assessments, estimates and assumptions have been made by our management that affect the application of accounting policies and reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Relevant estimates and assumptions are reviewed regularly. Revisions to accounting estimates are recognized in the period in which the estimate is revised and in any future affected period. Main estimates based on hypothesis basically refer to:

- *Potential impairment of non-financial assets*: We analyze the existence of impairment indicators for non-current assets at the end of each reporting period. Impairment tests require an estimation of the value-in-use or of the fair value minus de cost of sale of assets or cash generating units. Estimating a value in use or fair value minus costs of sale requires us to make an estimate of future cash flows expected from the asset or cash-generating unit and also to determine an appropriate discount rate to calculate the present value of these cash flows.

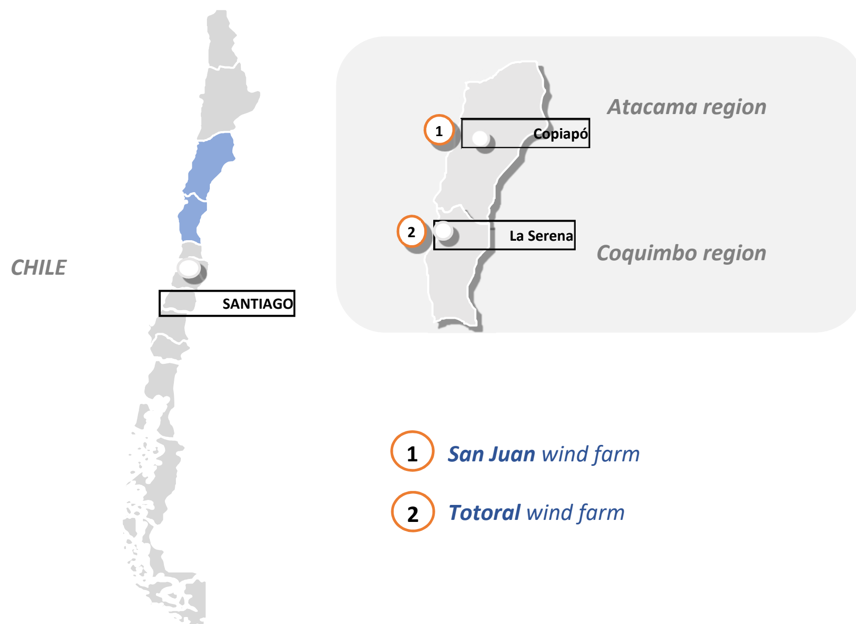
- *Deferred tax assets*: Deferred tax assets are recognized for all unused tax losses, insofar it is probable that there will be future taxable profit against which the losses can be used. We make estimates of our future tax results to determine the recognition and measurement of deferred tax assets.

OUR BUSINESS

Overview

We are a clean energy company that owns and operates wind generation plants with an aggregate installed capacity of 239.2MW and is engaged in the generation of electricity business in northern Chile. We own and operate two wind farm projects: (i) the San Juan Project, a 193.2 MW facility located in Vallenar in the region of Atacama, currently the second largest wind farm project in the country, and (ii) the Totoral Project, a 46.0 MW facility located in Canela, in the region of Coquimbo. The San Juan Project has been fully operational since March 2017 and the Totoral Project has been fully operational since January 2010. Both wind projects are located in areas characterized for their strong and highly predictable wind resource, which is considered favorable for the development of wind farms utilizing Vestas.

The map below provides an overview of the location and general specifications of the San Juan Project and the Totoral Project:



Source: ILAP.

We sell the electric power generated by our wind farm projects into the SEN (*Sistema Eléctrico Nacional*), the national electric system of transmission that provides electricity to almost the entire country. The SEN was created in 2017 after the interconnection of the two largest existing systems in the country, the SIC (*Sistema Interconectado Central*) and the SING (*Sistema Interconectado del Norte Grande*). The operation of the SEN, the SIC and the SING is coordinated by the National Electrical Coordinator.

Our main customers are highly-rated regulated DisCos (utility power distribution companies) and other large, experienced companies in varied industrial sectors (through long-term power purchase agreements (PPAs)), which provide a very stable source of recurring cash flow. As of March 31, 2021, 89.7% of our capacity at P50 is fully contracted under PPAs with tenors ranging from 4 to 12 years, and a weighted average life span of existing PPAs of 10.6 years, with DisCo PPAs expiring between 2031 and 2033. For the three-month period ending March 31, 2021, 86.9% of our revenue derived from sales of energy from PPAs, and over the fiscal years ended December 31, 2020, 2019 and 2018, 94.1%, 92.8% and 83.8% of our revenue derived from sales of energy from PPAs, respectively. Our most important individual PPA counterparty is Metro (Empresa de Transporte de Pasajeros Metro S.A., the operator of Santiago's subway system), a government-controlled entity rated A and A- by S&P and Fitch Ratings, respectively, representing 12.0% of our revenue for the three-month period ending March 31, 2021, and 13.1%, 27.9% and 24.8%

for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively. The PPA with Metro expires in 2032. See "*—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*." We sell any excess energy to other power generation companies in the spot market. Spot market revenue represented in aggregate 13.1% of our revenue for the three-month period ending March 31, 2021, and 5.9%, 7.2% and 16.2%, for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively.

For the three-month period ending March 31, 2021, our total net generation was 129.4 GWh, and for each of the years ended December 31, 2020, 2019 and 2018, our aggregate net generation was 601.1 GWh, 661.3 GWh and 634.6 GWh, respectively, with an aggregate availability factor of 94.5%%, 95.9%, 96.9% and 97.3%, and an aggregate capacity factor of 25.0%, 28.7%, 31.8% and 31.4%, respectively. According to the Independent Engineer, the average annual sold generation by the San Juan Project since start of operations is 551.7 GWh/yr and the average total windfarm availability is 96.3%, and the average annual sold generation by the Totoral Project since start of operations is 80.1 GWh/yr and the average total windfarm availability is 96.8%.

For the three-month period ending March 31, 2021, our revenue totaled US$15,617 thousand, and with respect to each of the fiscal years ended December 31, 2020, 2019 and 2018, our revenue totaled US$72,887 thousand, US$62,516 thousand and US$52,097 thousand, respectively. Our Adjusted EBITDA increased from US$28,509 thousand to US$33,741 thousand from the year ended December 31, 2018 to the year ended December 31, 2019, and further, increased to US$36,887 thousand from the year ended December 31, 2020. Our Adjusted EBITDA decreased from US$9,607 thousand to US$5,571 thousand from the three-month period ending March 31, 2020 to the three-month period ending March 31, 2021, due to an increase in marginal costs as further explained under "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Our Results of Operations—Revenues—Factors Affecting the Level of Revenues—Volatility Conditions During the three months ended March 31, 2021.*"

The Projects

San Juan Project

The San Juan Project is a 193.2 MW wind farm facility located in Vallenar, Region of Atacama, Chile (approximately 650 Km north of Santiago). The asset is comprised of 56 Vestas V117-3.45 MW wind turbines, making it the second largest single wind farm in Chile. The San Juan Project began partial operations in July 2016 and achieved full commercial operation in March 2017. The San Juan Project was built by Elecnor, a leading global EPC and renewable energy investor, and employs wind turbines supplied by Vestas, the world's most experienced wind turbine manufacturer. Vestas is responsible for the operation and maintenance of the turbines under the Service and Availability Agreement between San Juan and Vestas dated March 25, 2015, as amended on January 29, 2021, through 2037, that guarantees generation availability of 97% per turbine, increasing to 98% starting in 2022. See "*—Operations and Maintenance—O&M Agreements*." According to the Independent Engineer, Vestas has an excellent history of supporting wind turbine manufacture, installation and operations across the world.

According to Vestas, the expected useful life of the wind turbines with respect to the San Juan Project is up to 30 years, provided a proper and adequate maintenance plan is in place, and the remaining useful life is expected to be 25 years with respect to the San Juan Project. The San Juan Project was originally developed by our parent LAP Chile, and its current legal owner is San Juan, which we formed on 2013.

The area surrounding the San Juan Project is characterized by its strong and highly predictable wind resources (averaging 7.5 m/s at hub height). According to the Independent Engineer, this climate is considered favorable for the development of wind farms utilizing Vestas V117-3.45 MW turbines. Since commencing operations, the San Juan Project has exhibited average annual generation of 551.7 GWh/yr. and an average availability of 96.3%. The San Juan Project sells power into the SEN and is connected to the grid at the Punta Colorada substation owned by Transelec, via an 85km transmission line at 220 kV. We have an interconnection agreement with Transelec that will remain in force as long as the connection line is installed and in operation. See "*—Interconnection and Interconnection Maintenance Agreement*." For further details on the key equipment and technology of the San Juan Project, see "*—Equipment and Technology*" below.

San Juan, as the legal owner of the San Juan Project, is party to 67 long-term PPAs with a diversified group of DisCos to supply Regulated Customers. These offtakers are highly regulated entities that provide electricity service to both non-regulated and regulated end customers in Chile. These PPAs consist of U.S. Dollar denominated 15-year "take-and-pay" agreements, and were entered into after the tender process known as "2013-3 Second Call Auction/Tender Process" administered by the CNE, the Chilean National Energy Commission (*Comisión Nacional de Energía*), held in December 2014. In 2016, San Juan also entered into an additional offtake agreement with Metro, an Unregulated Customer rated A by S&P and A- (Stable) by Fitch Ratings. Under that agreement, San Juan has contractually committed to supply up to 60% of Metro's hourly consumption that is not supplied by solar priority suppliers. In addition, San Juan has a PPA entered into in 2017 with Enel Distribución, a power distribution company controlled by Enel Chile (rated BBB+ by S&P, Baa2 by Moody's and A- (Fitch), for which we provide an annual average contracted energy of 180 GWh (with a "take-or-pay" of 70%, 126 GWh) until 2023. The PPA allowed Enel Distribución to secure electricity volumes to supply Enel Distribución's unregulated customers. However, effective January 1, 2021, Enel Distribución assigned the PPA to Enel Generación as a result of regulatory changes introduced to the Electricity Law that prevented distribution companies to dedicate to business other that the supply of electricity to regulated customers. Enel Generación is the largest power company in Chile, also controlled by Enel Chile (rated BBB+ by S&P, Baa1 by Moody's and A- by Fitch). See "*Our Business—Commercial Strategy, Revenue Model and Customers—The Power Purchase Agreements (PPAs)*."

The San Juan Project provides annual average contracted energy of 381 GWh with respect to the PPAs with DisCos, 75 GWh with respect to the PPA with Metro and 180 GWh with respect to the PPA with Enel Generación, at average PPA prices of US$109.97/MWh, US$102.18/MWh, and US$48.65/MWh respectively.

Totoral Project

The Totoral Project is a 46.0 MW wind farm facility located in Canela, Region of Coquimbo, Chile (approximately 300 km north of Santiago). The asset is comprised of 23 Vestas V90-2.0 MW wind turbines and began commercial operations in January 2010. The Totoral Project was built by SKANSKA, a world-leading project development and construction group, and with wind turbines supplied by Vestas.

According to Vestas—our turbine provider and current O&M (operations and maintenance) contractor—the expected useful life of the wind turbines with respect to the Totoral Project is up to 30 years, provided a proper and adequate maintenance plan is in place, and the remaining useful life is expected to be 20 years with respect to the Totoral Project. Vestas is responsible for the operation and maintenance of the turbines under the Service and Availability Agreement between Norvind and Vestas dated April 1, 2013, as amended on December 14, 2016 through 2029, that guarantees generation availability of 97% per turbine. See "*—Operations and Maintenance—O&M Agreements*." The Totoral Project's legal owner is Norvind and was originally developed by SN Power AS. We acquired Norvind from SN Power AS in 2013.

The area surrounding the Totoral Project is characterized for its steady wind resource. Since commencing operations, the Totoral Project has exhibited average annual generation of 83.4 GWh/yr. and an average availability of 97%. The Totoral Project also sells power into the SEN, and is connected to the grid at the Las Palmas substation owned by Transelec, via a 7 km transmission line at 220 kV. We have an interconnection agreement with Transelec that will remain in force as long as the connection line is installed and in operation. See "*— Interconnection and Interconnection Maintenance Agreement*." For further details on the key equipment and technology of the Totoral Project, see "*—Equipment and Technology*" below.

Norvind, as the legal owner of the Totoral Project, was also awarded long-term U.S. Dollar denominated PPAs as a result of "2013-3 Second Call Auction/Tender Process" in December 2014. Norvind has 23 PPAs with 23 DisCos to supply Regulated Customers consisting of DisCos that began in January 2019 and will continue through December 2033. Under these agreements, the Totoral Project will sell an annual average of 45.5 GWh of contracted energy at an average PPA price of $113.2/MWh. Additionally, Norvind has 15 bilateral PPAs with Unregulated Customers and a power generation company to supply an average of 8.9 GWh expiring between 2022 and 2025. The Unregulated Customers range from large retail stores to universities and agro-industrial facilities. In aggregate, for the three-month period ending March 31, 2021, the Totoral Project's PPAs comprised 11.8% of our consolidated revenue, and for each of the years ended December 31, 2020, 2019 and 2018, these PPAs comprised 13.7%, 10.7% and 5.7% of our consolidated revenue, respectively.

PPAs and Main Counterparties

We earn contracted revenues from our PPAs with Contracted Customers (customers subject to a PPA), consisting of DisCos, Unregulated Customers and certain power companies (i.e. Enel Generación, Pacific Hydro Chacayes and Cinergia). We sell any excess power in the spot market. As of the date of this offering memorandum, we are party to 108 PPAs with 41 separate counterparties: San Juan is party to 67 PPAs with DisCos and three with Unregulated Customers, and Norvind is party to 23 PPAs with DisCos and 15 with Unregulated Customers. Our PPAs, in aggregate, have a weighted average term of 10.6 years.

For the fiscal year 2021, we estimate that 623.63 GW/h of our total generation capacity (at P50) will be contracted, representing 98.44% of the estimated total generation for the period. During the three months ended March 31, 2021 we sold 128.0 GW/h to Contracted Customers, and during the years ended December 31, 2020, 2019 and 2018, we sold 609.9 GW/h, 532.9 GW/h and 360.1 GW/h to Contracted Customers, respectively. During the three months ended March 31, 2021, 13.1% of our total revenues corresponded to energy sold in the spot market, and during the years ended December 31, 2020, 2019 and 2018, the energy sold to the spot market represented 5.9%, 7.2% and 16.2% of our total revenues, respectively.

PPAs with DisCos are long-term contracts, generally with a 15-year term, and serve Regulated Customers who have a peak load below 5 MW (customers with a peak load between 0.5 MW and 5 MW who are located in the area of a concession of a DisCo, may choose to be Unregulated Customers). The contractual terms and conditions, with the exception of the tariff, contracted demand and contract period clauses, are standard in nature and non-negotiable. These PPAs generally consist of U.S. Dollar denominated 15-year "take-and-pay" agreements, and were entered into after the tender process known as "2013-3 Second Call Auction/Tender Process" administered by the CNE, held in December 2014. During that process, San Juan was awarded Blocks 2-A, 2-C and 3, and Norvind was awarded Block 4, with end dates between December 31, 2031 and December 31, 2033. As a result, our Projects have received favorable long-term contracts with a diversified group of DisCos.

The table below summarizes the tenors, prices and contracted demand for each of the blocks awarded:

Company	Block	Client	Beg. Date	End Date	Term	Price (USD/MWh)	Energy GWh/y
San Juan	**2-A**	23 DisCos(1)	January 1, 2017	December 31, 2031	15 years	100.646(2)	68.2
San Juan	**2-C**	23 DisCos (1)	January 1, 2017	December 31, 2031	15 years	100.646(2)	40.8
San Juan	**3**	23 DisCos (1)	January 1, 2018	December 31, 2032	15 years	103.221(2)	272.5
Norvind	**4**	23 DisCos(1)	January 1, 2019	December 31, 2033	15 years	113.221(3)	45.5

(1) CGE Distribución S.A., Compañía Nacional de Fuerza Eléctrica S.A., Empresa Eléctrica Atacama S.A., Empresa Eléctrica de Antofagasta S.A., Luzlinares S.A., Luzparral S.A., Chilquinta Energía S.A., Energía de Casablanca S.A., Compañía Eléctrica del Litoral S.A., Enel Distribución Chile S.A. (formerly Chilectra S.A.), Compañía Eléctrica Osorno S.A., Empresa Eléctrica de la Frontera S.A., Sociedad Austral de Electricidad S.A., Empresa Eléctrica de Casablanca S.A., Cooperativa Eléctrica de Curicó Limitada, Cooperativa de Consumo de Energía Eléctrica de Chillán Limitada, Cooperativa Eléctrica de Los Ángeles Limitada, Cooperativa Eléctrica Paillaco Limitada, Cooperativa Regional Eléctrica Llanquihue Limitada, Cooperativa Rural Eléctrica Río Bueno Limitada, Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Limitada, Compañía Distribuidora de Energía Eléctrica Codiner Limitada and Empresa Eléctrica de Puente Alto Limitada.

(2) Average price from three awarded offers to the specific block.

(3) Price from one awarded offer to the specific block.

The four largest DisCo counterparties (Enel Distribución, CGE Distribución, Chilquinta Energía and SAESA) supply 97% of the total regulated clients of the SEN, and three of these DisCos have an investment grade rated parent company. The table below summarizes the main credit characteristics of these counterparties.

	Compañía General De Electricidad Distribución S.A.	Enel Distribución Chile S.A.	Chilquinta Energía S.A.	Sociedad Austral De Electricidad S.A. (SAESA)
Overview	Formerly known as Gas Natural Fenosa Chile S.A., CGE is a Chile based company founded in 2003 that is principally engaged in the energy sector. The company main activities include transmission and supply of electric energy. CGE business operations are in Chile and Argentina.	Founded in 1921 and formerly known as Chilectra S.A., Enel Distribución operates in the distribution and sale of energy. And is one of the largest electricity distribution company in Chile. Its concession area covers 2,065.4 km², considering 33 communes in the Metropolitan Region, including the capital city Santiago.	Founded in 1889, it operates as an energy supply service company. The company provides installation, transmition, maintenance and distribution of electricity and natural gas. Chilquinta Energia serves customers in Chile.	Founded in 2009, it operates as an electrical power distribution company. The company provides electric energy generation, installation, and distribution through substation power lines. Sociedad Austral de Electricidad serves residential, commercial, and industrial customers in Chile.
Rating	A+ (Fitch) / AA- (Feller) - Local	Not rated	AA (Humphrey's) / AA (Fitch) - Local	AA+ (ICR) / AA+ (Feller) - Local
Parent Company	Naturgy	Enel Chile	State Grid Corporation of China	AIMCO / OTPP
Parent Rating	BBB (S&P) / Baa2 (Moody's) / BBB (Fitch)	BBB+ (S&P) / Baa2 (Moody's) / A- (Fitch)	A+ (A&P) / A1 (Moody's)	Not rated
Number of Clients	3,066,3920	2,008,018	758,739	921,560
Coverage Reach	45%	30%	11%	14%
Energy Sold (GW/h)	10,876	16,481	2,384	3,767
Market Share	33%	49%	8%	10%

PPAs with Unregulated Customers or other power companies can be negotiated directly between the seller and the offtaker and are not subject to the tariff structure defined by National Energy Commission; hence the parties may freely choose a provider and freely agree the energy price. As of the date of this offering memorandum, we have signed 18 PPAs with Unregulated Customers and power companies (three in connection with the San Juan Project and 15 in connection with the Totoral Project), with varied terms and prices.

Our most important individual PPA counterparty is Metro. Our contracted energy with Metro is 75 GW/h per year at US$102.18/MWh. This contract represented 12.0% of our revenue for the three-month period ending March 31, 2021, and 13.1%, 27.9% and 24.8% for each of the fiscal years ended December 31, 2020, 2019 and 2018, respectively. The PPA with Metro expires in 2032.

Another important counterparty is Enel Generación for which we provide an annual average contracted energy of 180 GWh (with a "take-or-pay" of 70%, 126 GWh) at US$48.65/MWh under a PPA that is currently set to expire in 2023. Enel Generación is the largest power generation company in Chile, operating 3,468 MW of installed capacity from renewable sources and 2,454 MW of installed capacity from thermal sources, for a total of 6,000 MW of installed capacity. In 2020, its market share in energy sales reached 30.4% of the total energy sold in the SEN and sold 21,811 GW/h. Enel Generación is rated BBB+ by S&P, Baa1 by Moody's and A- by Fitch.

The table below highlights the most relevant features with respect to our most relevant PPAs by group:

Offtakers	DisCos	Enel Generación	Metro	Other Unregulated Customers
Contracted Energy (GWh per Year)	427[(1)]	180	75	Incremental from 38 GWh in 2021 to 82 GWh in 2023
Tenor	2031 - 2033	2023	2032	2023 – 2025
Volume Risk	Yes - Take and pay	Yes – 30% take and pay	Yes - Take and pay	Yes - Take and pay
Currency	US$ Denominated	US$ Denominated	US$ Denominated	US$ Denominated
Revenue Streams	Energy Sales	Energy Sales	Energy Sales NCRE Credits	Energy Sales
Energy Dispatch Costs Pass through	Yes - (Transmission and Capacity Charges)	N/A	Yes - (Transmission and Capacity Charges)	Yes - (Transmission and Capacity Charges)

(1) Sum of all DisCo PPAs.

Availability; Production; Generation Capacity

The following tables summarize the average total windfarm availability and power factors for each of the Projects, for the years indicated below:

San Juan Project		
Year	**Availability**	**Power Factor**
2017	93.3%	34.2%
2018	97.4%	34.2%
2019	97.0%	34.5%
2020	95.3%	30.8%

Totoral Project		
Year	**Availability**	**Power Factor**
2017	95.8%	19.0%
2018	96.9%	20.2%
2019	96.6%	20.7%
2020	97.3%	19.6%

The following tables summarize certain production metrics for each of the Projects, for the years indicated below, with a 97% aggregate availability:

San Juan Project

Exceedance probability	Generation GWh
P10 (1 year)	625.6
P50	552.1
P90 (1 year)	478.6

Totoral Project

Exceedance probability	Generation GWh
P10 (1 year)	92.1
P50	81.4
P90 (1 year)	70.7

San Juan Project

Year	Production (GWh)	Specific Curtailment (GWh)	Solved Failure (GWh)	Adjusted Generation (GWh)	Comments
2017	553.5	88.0	-	641.5	Major curtailment due to system transmission line capacity
2018	553.3	63.7	-	616.8	Major curtailment due to system transmission line capacity
2019	579.4	21.7	-	599.8	500kV transmission line COD in June 2019, allowing from then the dispatch of all energy
2020	522.8	13.5	29.4	565.0	Curtailment for delayed maintenance of transmission lines supporting the new 500kV. Zigzag transformer overload produced a stoppage in one of San Juan's circuits for 36 days. A spare zigzag was purchased and all of the MV cables were changed from incomer to the LV side of the power transformer.

Totoral Project

Year	Production (GWh)	Curtailment (GWh)	Solved Failure (GWh)	Adjusted Generation (GWh)	Comments
2017	76.7	10.4	-	87.1	Major curtailment due to system transmission line capacity
2018	81.5	9.1	-	90.6	Major curtailment due to system transmission line capacity
2019	83.2	4.2	-	87.4	500kV transmission line COD in June 2019, allowing from then the dispatch of all energy
2020	79.0	2.7	0.0	81.7	

Wind Resource

Both Projects benefit from a strong and highly predictable coastal wind resource (7.5 m/s for the San Juan Project and 5.6 m/s at the Totoral Project at hub height).

An independent engineer reviewed the wind production at the San Juan and Totoral Projects with data based on actual performance since they began commercial operation. Actual data from the operational period has been scaled to long term expectations based on meso-scale data available for Chile. The tables below summarize the results of the annual energy production assessments.

P Values	1 year average			10 year average		
	San Juan	Totoral	Combined	San Juan	Totoral	Combined
P50	552,1	81,4	633,5	552,1	81,4	633,5
P90	478,6	70,7	549,3	498,5	74,6	573,1
P99	418,6	61,9	480,5	454,7	69,1	523,8

According to the Independent Engineer Report, the external wake loss factor with respect to the San Juan Project from nearby operational assets is 87.6%, presented on a blended basis, which includes actual losses from Cabo Leones I (181.5 MW, operational since June 2018) and Sarco (170.2 MW, operational since July 2020), and estimated wake losses from Cabo Leones III (which began operations in December 2020). According to the Independent Engineer, an extension to Cabo Leones is in construction phase, which is due to commence operation during the next 12 months, based on reports from developers. The San Juan Project does not receive compensation for the wake effect by the other wind projects.

Our Corporate and Ownership Structure

ILAP is a limited liability company (*sociedad de responsabilidad limitada*) formed under the laws of Chile, and is 99.9999% owned by Latin America Power S.A. ("*LAP Chile*"), a corporation (*sociedad anónima*) formed under the laws of Chile, and 0.00001% by Latin America Power Holdings B.V. ("*LAP*"), a Dutch corporation. ILAP owns all but one share in San Juan and all but one share in Norvind, with the remaining share in each case owned by LAP Chile.

LAP owns all but one share of LAP Chile, and Latin America Power Panama S.A. ("*LAP Panama*") owns the remaining share. LAP is a power generation company created with the goal of improving the energy matrix for Chile and Peru through the development of renewable energy sources, while also maintaining close relationships with neighboring communities and protecting the environment. LAP identifies, develops, builds and operates hydro and wind projects. LAP currently owns a total of 10 projects with an aggregate capacity of approximately 342MW.

Our ultimate beneficial owners are:

- ***BTG Pactual Brazil Infrastructure Fund II (45.85%)*** is managed by BTG Pactual Brazil, the leading investment bank in Latin America. It holds approximately US$58 billion in assets under management. BTG Pactual Brazil has an extensive track record in investing in the electrical power through the administration of funds. BTG Pactual Brazil has invested in projects which generate more than 3,500 MW. It was a pioneer in wind power investment in Brazil, through Bons Ventos Park (155 MW). Currently holds a participation in renewables assets, thermal plants and transmission lines. In addition, is a leading financial group with operations in energy trading in Brazil.

- **Patria Investments (Patria)** ***(45.85%)***, which manages the Patria Funds mentioned above, is one of the most traditional alternative investment firms in Latin America. Patria is a pioneer in private equity investments in the region, with over 30 years of experience. The firm currently has over US$ 14.4 billion of assets under management, in funds dedicated to Private Equity, Infrastructure, Real Estate, Public Equities, Agribusiness and Credit Solutions. Patria's infrastructure group, which currently manages US$ 4.7 billion in assets, has significant experience investing in energy. Prior to LAP, Patria co-founded Energías Renováveis S.A. ("*ERSA*"), a leading player in renewables in Brazil, alongside GMR Energía. Patria currently holds interests in CPFL Renovaveis, the largest renewable energy company in Latin America, with a diversified portfolio of hydro, wind, solar and biomass assets. As of December 2020, Patria's Infrastructure Group held interests in 14 companies, including LAP.

- ***GMR Holding B.V. - (8.30%).*** GMR Holding is a Dutch company affiliate of PWR Capital group and holds its investments in Renewable Energy in Latin America.

Our History

LAP was formed in 2011 by a Brazilian entrepreneur named Roberto Sahade, taking advantage of the thriving and efficiently regulated Chilean electrical market, with the goal of developing and operating all-renewable power plants in Chile and other Latin American countries. The first investments were made to purchase water use rights in the south of Chile, and participation in six run-of-river hydro projects in Peru (two of them are still in operation).

In 2013, LAP acquired 100% of the shares of Norvind S.A. from SN Power AS. In parallel, LAP started to develop and seek greenfield projects in order to create a portfolio of generation assets, first in Chile, and later in the neighboring Peru.

In the public auction named "2013-3 Second Call auction" held in 2014, LAP bid energy from the operating Totoral Project and the San Juan Project, which was still in development. As a result of this auction, the Totoral Project was awarded a 15-year contract to supply 45.5 GWh/year to the regulated DisCos from January 1, 2019 to December 31, 2033 and, in the same process, the San Juan Project was awarded 381 GWh/year to supply energy to DisCos for the same period of time.

After securing cash flow stability, LAP entered into turnkey construction agreements with Elecnor, a leading global EPC and renewable energy investor, to build the San Juan Project. The San Juan Project work was completed by Elecnor in September 2016. Vestas, the world's most experienced wind turbine manufacturer, became the provider of wind turbines for both Projects and is also their current O&M service provider. The terms of the O&M Agreements with Vestas guarantee generation availability of 97% per turbine in both Projects, and 98% with respect to the San Juan Project starting 2022. ILAP became the owner of both projects in 2017.

Our principal executive offices and corporate headquarters are located at Cerro El Plomo 5.680, oficina 1202, Las Condes, Santiago, Chile, and our telephone number is +56 2 2820 3200.

Competitive Strengths

Attractive Macroeconomic Fundamentals

Chile offers one of the most business friendly environments in the region: competitive economy, transparent regulatory regime and stable credit status. Chile is rated A by S&P, A1 by Moody's and A- by Fitch. As of 2019, it has a nominal GDP of US$282 billion and a GDP per capita of US$23.6 thousand, with a 7.1% unemployment rate. Chile's public debt as a percentage of GDP is 36%. As of 2019, it showed a diversified economic activity, led by the services industry (39%), followed by industrials (14%), mining (10%) and construction (10%).

Proven Assets with Stable and Predictable Wind Resource and Best-in-Class Design

The San Juan Project began partial operations in July 2016 and achieved full commercial operation in March 2017. The Totoral Project began commercial operations in January 2010. Both Projects benefit from a strong and highly predictable coastal wind resource (7.5 m/s at the San Juan Project and 5.6 m/s at the Totoral Project at hub height). Both Projects utilize Vestas wind turbines, which offer best-in-class design and technology. Vestas is a market leader with 136 GW of installed capacity worldwide, over 40 years of experience and more than 80,000 turbines installed and connected to date, 443 of them in Chile with a generation capacity of 1,044 MW. The San Juan Project operates 56 Vestas V117-3.45 MW wind turbines, designed to be installed at medium or high wind sites, maximizing generation for wind speed. The wind performance at the San Juan Project was improved by the incorporation of a PowerPlus upgrade package offered by Vestas in the base case, which increased the energy production per turbine from 3.3 MW to 3.45 MW, increasing therefore the installed capacity from 184.8 MW to 193.2 MW. The Totoral Project operates 23 Vestas V90-2.0 MW wind-turbines to be low weight with a lower load to reduce foundation costs without sacrificing durability or impacting asset life. The V90-2.0 MW blades are one of the lightest 44 m blades in the market maximizing availability and wind generation during moderate wind periods. All the major components have been designed to allow for fast and efficient repair and have undergone highly accelerated lifetime tests. The technology allows for an asset life extension strategy backed by a detailed long-term O&M program and preventative maintenance plan with Vestas.

Highly-rated PPA Counterparties

Throughout the term of the Notes, we expect that our revenue will consist of approximately 92% from Contracted Customers, including DisCo PPAs, Unregulated Customers PPAs, NCRE (non-conventional renewable energy) contracts and capacity payments. The weighted average rating of the DisCo obligors is "AA-" on the Chilean local scale (equivalent to "BBB" in the international scale), and the overwhelming majority of the DisCo obligors are owned by large, highly-rated international strategic companies (Naturgy, Enel, State Grid, AimCo & Ontario Teachers' Pension Plan). The Chilean DisCos operate as natural monopolies, of which the largest four DisCos (Enel Distribución, Chilquinta Energía, CGE Distribución and SAESA) account for approximately 97% of the total regulated clients of the SEN and maintain local investment grade ratings. In addition, the Metro contract serves as a natural hedge against the risk that the DisCos are over-contracted, as any additional generation at the San Juan Project beyond the amount sold through the DisCo PPAs is available to be sold to Metro, Enel Generación, Cinergia, other potential new PPA client, or the spot market.

In aggregate, the DisCo PPAs represent stable contracted cash flows that are Dollar denominated, inflation indexed, and diversified across a series of market participants providing a critical service through a monopolistic distribution network. This combination of Contracted Customers creates a diverse set of cash flows with limited exposure to any single counterparty. Furthermore, there are special rules and procedures in place to ensure business continuance in case of a DisCo's insolvency or concession revocation. The latter supports the Projects' operational stability, because our operations may rely on stable and predictable market conditions in which all the off-takers are subject to the same set of rules.

Industry Leading O&M Support and Appropriate Insurance Coverage

We use state of the art industry leading O&M support. We have developed and implemented a unified system and preventative maintenance plan for all aspects of electrical, technical and design maintenance by signing comprehensive O&M Agreements with Vestas and subcontracting specialists to enhance O&M support. The contracts include 24/7 monitoring, control and operation, including preventive and corrective maintenance, and unscheduled maintenance due to failures, breaks or under performance not as a result of any excluded event. It also includes O&M expenses such as workforce, spare parts, consumables, tools and lifting equipment. Vestas will perform the scheduled and unscheduled maintenance of the San Juan and Totoral Projects through 2037 and 2029, respectively, under the current contracts, which guarantee 97% availability per turbine for both Projects (98% availability in the San Juan Project starting 2022), subject to financial penalties.

Both Projects have insurance coverages that are in line with those of similar assets and industry standards, adequate to properly mitigate for the operational risks of the Projects. According to the Independent Insurance Advisor the Company has property damage and business interruption coverage with an aggregate total value of US$552,336,542, and general liability and D&O insurance coverage in line with markets standards.

Transparent Market with Significant Regulatory Oversight

Since the liberalization of the electricity market in 1982, the Chilean power industry has undergone significant regulatory changes, consistently increasing transparency and competition in the marketplace, including mechanisms for long-term contracts to supply Regulated Customers, the introduction of a spot market, stable capacity markets and NCRE revenues. The combination of these revenues creates a diversified cash flow profile that is supportive of long-term financing and asset development. These changes to the Chilean power industry have resulted in a stable and favorable regulatory environment for independent power producers like us.

Our Projects consist in NCREs, which Enjoy Strong Governmental Support under the NCRE Law

Recent legislation in Chile supports the increased development of renewable generation resources compared to other technologies that may rely on fossil fuels or that may release carbon emissions to the atmosphere. The NCRE Law, encourages the development of non-conventional renewable energy units by requiring that a certain amount of electric power withdrawn by power companies be generated by NRCEs (20% by 2025), reflecting Chile's commitment to renewable generation and increasing renewable energy demand growth to 13.6% annually through 2025 to comply with regulations. The NCRE Law created an NCRE credits market and a penalty applicable to generation companies that do not meet the minimum NCRE generation amount or do not purchase sufficient NCRE credits. In 2019, the Chilean government and the largest companies having interests in coal-fired generation (Enel, AES Gener, Engie and Colbún) reached a voluntary agreement (as further developed in 2020) not to initiate the construction of new coal-fired power plants and to work on a progressive decommissioning schedule to dismantle those facilities by 2040. This agreement has further encouraged the development of NCRE projects to replace the coal-fired power plants being decommissioned. These and other programs that may arise in the future, showcase the Chilean government's commitment with renewable energy.

Market Design Supports Contracted Revenues

In May 2005, the Ministry of Economy instituted Short Law II requiring DisCos to participate in a competitive tender/auction process to secure their electricity supply through long-term fixed price contracts. The goal was to address uncertainties regarding future electricity supply by establishing volume requirements, setting fixed prices for medium and long-term supply and predicting demand three years in advance. In 2015, the Energy Tender Process Reform (Law 20,805) was enacted to improve the tender process and limit/prevent oversupply conditions. In order to do so, the auction structure tied the DisCo revenue to their demand forecasting accuracy via the VAD tariff; DisCos receive revenue based on how closely they can predict their energy demand relative to a "model" company.

Demand shortfall is distributed pro rata throughout all DisCo PPA contracts and the generation impact is shared proportionately by all of the DisCos. The PPA contracts therefore provide stability due to the shared risk amongst all the DisCos, creating a low likelihood of systemic default within the DisCo market. The DisCos have also been historically resilient and only one major DisCo has defaulted on its contracted agreements since the implementation of the auction and contracting reform. The risk associated with the San Juan and Norvind DisCo PPAs is mitigated by distributing sales of energy across 67 PPAs with 23 counterparties, which participated in the 2013-3 Second Call auction.

The market design has anticipated critical risks that would otherwise disincentive investors from participating in the Chilean market. Currency risk is mitigated through Dollar indexed PPAs. Inflation risk is reduced through the CPI or U.S. CPI index. Counterparty risk is reduced through distribution across multiple DisCos as well as through a mechanism allowing the government to intervene in the event of DisCo insolvency. The stability of contracted revenues creates a highly resilient cash flow profile, supplemented by capacity revenues, NRCE contracts and a strong spot market. In addition, the Unregulated Customer PPA market is broad and efficient enough to allow generating companies to counter mid-term oversupply situations by signing bilateral contracts with energy retailers or end customers, therefore reducing the spot market exposure. We believe all these factors will enable us to ensure regularity of cashflows available for debt service payments through 2031.

Experienced Key Management Team

Our senior management team has extensive experience in the development and operation of renewable energy in Chile, with more than 18 years on average of experience in the energy industry in Chile and Latin America, playing several roles as developers, partners and board members in different renewable energy companies. We benefit from our parent companies' experience in developing, owning and managing renewable assets in Chile and the region, and our representatives participate actively in industry groups such as the Chilean Generators guild (*Generadoras de Chile*), a trade association formed by the largest power generation companies in the country. Additionally, we have a dedicated internal team of technicians which work closely with Vestas providing support including administration and oversight over the period in which the manufacturer is responsible for the maintenance of the turbines.

Business Strategy and Objectives

Provide world-class service quality while operating our Projects safely, efficiently and sustainably

We strive to provide world-class quality of service while operating our facilities safely, efficiently and sustainably. Our business adheres to global benchmarks for safety, environmental and operating standards in the industry and we promote a culture of health, safety, accident prevention, security and environmental excellence by our employees, contractors and local communities. We are continually exploring the implementation of efficiency measures and renewable energy generation technologies in order to enhance the overall operational efficiency and sustainability of our Projects. We also follow strict corporate governance standards and seek to ensure fairness, transparency, accountability, and responsibility in the operation of our business for our owners and all stakeholders.

Maintain a solid financial profile with stable and predictable cash flows

We are committed to maintaining a solid financial profile, strong credit metrics, and providing stable returns to our owners. Our principal financial objectives include generating predictable and stable cash flows, maintaining adequate minimum liquidity and managing our debt amortization schedule in line with the tenor of our PPAs. Our business model, based on long-term PPAs covering our generation capacity in the long-term, protects us against electricity price fluctuations in addition to fluctuations in our variable costs and exchange rates.

Achieve Financial Excellence

Our financial policy focuses on profitability, stability and liquidity in order to maintain and develop our business and drive profitability. Our principal financial objectives include balancing our capital structure, maintaining an adequate liquidity and having a debt amortization schedule according to our cash flow generation to prevent cash flow and earnings volatility. The proceeds of this offering of Notes will be mainly used to satisfy in full all of our obligations under the NPA, to further reorganize our liabilities in the long term.

Maximizing Efficiency and Asset Life

We continue to improve and maintain our assets to optimize efficiency and cost effectiveness of operations on a day-to-day basis, as well as to maximize the lifespan of our assets, by ensuring proper O&M and applying industry best practices. We use state-of-the-art technology for the control and monitoring of our Projects with services rendered by leading companies like Nispera and Saroens, which allow us to predict our generation availability with better accuracy and anticipate system failures. See "*—Equipment and Technology*." Through the implementation of updated technologies and employee training programs in maintenance and operations of the Projects, together with maintaining our O&M Agreements AOM4000 with Vestas, we continue to modify our strategies and procedures to enhance asset operational reliability and life expectancy.

Maintain Constructive Relationships with Government Regulators and the Community

We continue to build and maintain constructive relationships with government regulators and local communities where our assets are located, with a focus toward mutually beneficial relationships with all parties involved in the operation and maintenance of our Projects, as well as those involved in the generation and sale of energy. In 2020, we were awarded first place for "good practices" in an annual contest held by the Chilean Generators guild (*Generadoras de Chile*), due to our management of relationships with communities. Our management policies are certified under the ISO9001:2015 standards.

Summary of Findings from Independent Engineer Report

The Independent Engineer prepared the Independent Engineer Report, a copy of which is attached as Appendix A to this offering memorandum. Below is a summary of the key findings of the Independent Engineer Report:

- The Projects have benefited from high levels of availability and production compared to budget expectations and performance has improved as the Company worked through minor ramp-up equipment issues, as would be expected in the early stages of these projects. Vestas contractually guarantees availability of the turbines at 97% for both sites. In 2021, this availability requirement will increase to 98% for San Juan. These levels of availability have consistently been achieved.

- The Projects have both encountered some losses, including grid curtailment, which would be expected in the early part of operations. Importantly, a new transmission line (Cardones-Polpaico 500 kV) was completed in 2019 and has reduced the level grid curtailment in 2020. The Independent Engineer notes that no formal log of curtailment is provided from the grid. However, the Independent Engineer recommends that the Company improve their method for quantifying and logging outages, which will help to isolate issues within the facility from true grid curtailment. Other minor breakdowns are considered by the Independent Engineer to be isolated events, which management has rectified and appropriate assumptions for future availability are included in the yield assessments for both projects.

- The Independent Engineer has undertaken an independent yield assessment for the two Projects, using industry-standard approaches. For Totoral, historical operating information from the period 2017-2020 was used to develop a post-construction yield assessment. The Independent Engineer's analysis indicates an average Net Yield of 81.4 GWh/ year (P50) and a 1-year P90 of 70.7 GWh.

- For San Juan, the Independent Engineer found that there has been a complicated ramp-up period: as new windfarms have been constructed between 2017 and 2020. While the Independent Engineer's post-construction yield assessment takes these effects into account, the 'clean' operating period is relatively short. The Independent Engineer considers there remain some uncertainties in the post-construction approach and so a blended pre-construction and post construction yield assessment has been used.

- The Independent Engineer's analysis indicates an average Net Yield of 552.1 GWh/ year (P50) and a 1-year P90 of 478.6 GWh. These values take into consideration the likely wake-losses from nearby development, Cabo Leones III, which began operation in December 2020, Sarco (2018), and Cabo Leones I (2020).

- The Company has an appropriate O&M/asset management approach, with an in-house staff covering both wind farms and some central resources to support other projects in the region. The Company benefits from a cloud-based maintenance management system and remote monitoring of the assets via SCADA to a control room situated in Santiago, Chile.

- There are opportunities for improvement to the Company's overall O&M approach, which the Company has indicated they intend to take, including better monitoring of production losses to help improve performance as well as a more robust inspection program, particularly for towers and foundations.

- Based on the information provided, the operating assets of the two Projects appear to be operating satisfactorily and are well-maintained. For the wind turbines and towers, the Vestas O&M contract provides a high-quality service to monitor and maintain this equipment. There have been a few, minor operating defects since start of operations, which Vestas have resolved.

- The San Juan Project suffered from a zig-zag transformer failure in July 2020, causing a partial outage for 36 days. This has been investigated and appeared to arise from combination of technical and operating factors. Measures are in place to ensure this issue be mitigated in future.

- The foundations for the wind farm are a key component in the overall project and the expected useful life of the asset. Should any problems arise during the operational phase, these can often be uneconomic to repair. The validation of an appropriate design and verification of construction quality are important to ensure that a useful life of more than 20 years for the foundations can be expected. Although no fundamental flaws have been identified with the design, a high-level review has shown that the fatigue analysis in the design phase was limited. The Independent Engineer therefore recommends that the Company should undertake a fatigue analysis, which the Company management has indicated they intend to undertake. The Independent Engineer recommends a downside sensitivity case to consider a 2% production curtailment from year 15 onwards to ensure that fatigue loads remain within the design-envelope of the foundations.

- The Independent Engineer understands that the Company is discussing life-extension with Vestas for the tower and wind turbine generators once the existing contracts expire (Totoral, March 2029; San Juan, March 2037). This is a reasonable strategy. Considering the appropriate maintenance strategy in the meantime, the Independent Engineer believes that from a commercial point of view, sufficient budget has been built in the financial model for the wind farms to operate for 30 years.

The summary of conclusions of the Independent Engineer Report above is qualified in its entirety by the report itself, which you should read before making an investment in the Notes. The Independent Engineer is an independent consultant with experience in the industry. For purposes of preparing its report, the Independent Engineer relied on information provided by us as well as government agencies.

Summary of Findings from Market Consultant Report

The Independent Market Consultant prepared the Independent Market Consultant Report, a copy of which is attached as Appendix B to this offering memorandum. This report, among other things, provides context on (i) the Chilean electricity market, explaining the regulatory framework with the most important laws that govern the market relevant to the Projects, (ii) the main entities and segments in the Chilean electricity market, (iii) market perspectives, methodological aspects for energy price projections and capacity credit estimation, (iv) ILAP's portfolio characteristics, (v) a review of the most relevant PPAs of both Projects, and (vi) the results of marginal cost projections and capacity credit projections. Below is a summary of the key findings of the Independent Market Consultant Report:

- The report notes that the San Juan Project has an installed capacity of 193.2 MW made up of 56 turbines, the second largest wind farm in Chile. The Totoral Project has an installed capacity of 46 MW made up of 46 Vestas V90/2.0 MW wind turbines. Located near the coast, the San Juan Project has a good capacity factor and relatively predictable generation cycle, whereas Totoral Project has a more unpredictable generation. In 2020, the San Juan Project generated 504.6 GWh, and the Totoral Project generated 79.5 GWh.

- The Independent Market Consultant Report describes recent updates to the Chilean electricity system. According to the Independent Market Consultant, Chile is in a period of transformation or transition associated with trends such as an increase in the participation of variable renewable generation sources, increasing participation of distributed generation, energy storage, among others. The changes that are contemplated include the incorporation of a new concept of "Flexible Capacity" to satisfy the needs of the flexibility of the systems concerning the ramps of the system, as well as the incorporation of modifications that integrate better "demand signals" for the determination and contribution to the sufficiency power, among others.

- The report also addresses the effects of the COVID-19 pandemic in the Chilean electricity market. The Independent Market Consultant explains that such effects can be observed in two main areas: on the one hand, there is a variation in electricity consumption. The report provides data showing that the percentage increase of residential demand of electricity from March to September 2020 ranged from 100% to 270%. On the other hand, the pandemic has caused delays in construction of electrical infrastructure. Of about 5,000 MW of generation under construction, projects currently representing almost 2,800 MW have delays, approximately 55% of the projects.

- The report provides monthly marginal cost and capacity projection results for five nodes: Crucero 220 kV, Maitencillo 220 kV, Las Palmas 220 kV, Quillota 220 kV and Charrúa 220 kV. It divides the data into Base Scenario and Downside Sensitivity. Under Base Scenario, the report concludes as follows: the expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 48.6 US$/MW; the expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 45.7 US$/MWh; the expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 45.5 US$/MWh; the expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 47.6 US$/MWh; the expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh. Under the Downside Sensitivity scenario, the report concludes as follows: the expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 38.6 US$/MW; the expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 37 US$/MWh; the expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 36.8 US$/MWh; the expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 38 US$/MWh; the expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh.

- The report concludes that the installed capacity of the SEN as of February 2021 totaled 26,376 MW. Thermal installed capacity, counting coal, natural gas, and diesel technologies have a share of 48.7% of the total installed capacity of the SEN. Hydro powered units (run-of-river and dam units) add up to 25.9% of the total installed capacity, while solar PV and wind-based technologies represent 23.3% of the SEN's installed capacity. The "big four" generating companies (Enel, AES Gener, Colbún, and Engie) own 60.9% of all the installed capacity of the SEN; however, given the increase in competitivity that has been seen during the last tendering processes for regulated and unregulated clients, the market share has diversified and permitted the entry of new competitors. Regarding the transmission segment, the main company is Transelec, with 27.6% of the market share. CGE and Interchile come afterwards with 10.7% and 5.5%, respectively. Transelec, CGE, Interchile, ENGIE, Colbún Transmisión, Minera Escondida, AES Gener, TEN, Chilquinta, STS and Enel Transmisión Chile form 70.9% of the whole market share. In the remaining 29.1%, there are 176 additional companies, totaling 187 transmission companies operating in the SEN.

- Finally, the report discusses the general methodology and main input data. It describes the main input data corresponding to the methodologies on which the projection of commercial revenues and costs are based. The data correspond to generation and transmission expansion plans, a decarbonization plan, fuel price projection, LNG availability and demand projection. In addition, methodological aspects related to energy marginal cost projection, capacity recognition projection are also addressed.

The summary of conclusions of the Independent Market Consultant Report above is qualified in its entirety by the report itself, which you should read before making an investment in the Notes. The Independent Market Consultant is an independent consultant with experience in the industry. For purposes of preparing its report, the Independent Market Consultant relied on information provided by us as well as government agencies.

Commercial Strategy, Revenue Model and Customers

Our commercial strategy is to sign long-term PPAs up to a contracted energy level equal to P90 of the annual generation expected, reducing our exposure to the volatility of spot market prices. In the last years, we have increased the overall contracting level with Unregulated Customers in order to offset oversupply risk in contracts with DisCos, reaching an effective contracting level of our commercial strategy, considering that the DisCos sales are below their contracted demand.

On the other hand, we have been able to sign contracts with clients from different industries, in order to obtain a well-balanced portfolio of clients, such as DisCos, mining companies, agroindustry entities, public transportation systems, retail stores and education. This way, we believe the risks related to payment and level of consumption, among others, are mitigated. Energy surpluses are sold in the spot market, where generation companies with shortfalls buy energy.

The Power Purchase Agreements (PPAs)

Chilean law distinguishes between two markets: (1) the spot market (or wholesale), and (2) the PPA market. The Chilean government through Short Law II and Distribution Auction Reform Law encourages competition in generation by compelling the DisCos to procure all electricity supplied to Regulated Customers through public auction/tender processes, resulting in long-term PPAs.

Generation companies may enter into PPAs with other generators, with DisCos or with Unregulated Customers. PPAs with DisCos are long-term contracts, generally with a 15-year term, and serve Regulated Customers, who have a peak load below 5 MW (customers with a peak load between 0.5 MW and 5 MW who are located in the area of a concession of a DisCo, may choose to be Unregulated Customers). The contractual terms and conditions, with the exception of the tariff, contracted demand and contract period clauses, are standard in nature and non-negotiable.

Both San Juan and Totoral Projects have received favorable long-term contracts with a diversified group of DisCos through distribution auctions. The four largest DisCo counterparties (Enel Distribución, CGE Distribución, Chilquinta Energía and SAESA) supply 97% of the total regulated clients of the SEN, and three out of four of these DisCos have an investment grade rated parent company.

The table below shows a summary of the main terms of the PPAs with DisCos:

PPA Information	**DisCos PPAs**	
	San Juan	**Norvind**
Number of Contracted Customers	23 DisCos	
Number of PPAs	90 PPAs(1)	
Contract Generation	381 GWh	45.5 GWh
Contract Term	15 years each Project	
Contract Commencement Year	2017/2018	2019
PPA Base Price (Bid price)(2) - US$/MWh	102.486(3)	113.221
PPA Indexed Price – US$/MWh	110.77(3)	122.66

(1) Each DisCo counterparty to San Juan has three PPA contracts each, one per block with the exception of ENEL Distribución Chile S.A. (formerly known as Chilectra S.A.) who has one PPA contract for all three blocks.
(2) 2013-3 Second Call auction.
(3) Weighted average price across PPAs (relative to the term of the relevant PPAs for each respective block) for the three blocks.

San Juan was awarded the contract term blocks described below in the 2013-3 Second Call auction, pursuant to which the facility began supplying energy under PPAs beginning in January 2017 and January 2018 respectively:

- 2-A (January 1, 2017 – December 31, 2031 / 00:00-07:59/23:00-23:59),
- 2-C (January 1, 2017 – December 31, 2031/ 18:00-22:59), and
- 3 (January 1, 2018 – December 31, 2032 / 24-hour block).

Norvind was awarded supply in Block 4 (January 1, 2019 – December 31, 2033 / 24-hour block) of the 2013-3 Second Call auction results, pursuant to which the facility began selling power to its offtakers in January 2019. All of the PPA prices are awarded in fixed price, U.S. Dollar denominated contracts that are indexed to the CPI rate of inflation. The PPAs awarded and executed by San Juan and Norvind are detailed in the chart below.

Asset	Offtaker	Awarded Block	Avg. Energy (GWh/year)	Average Awarded Price[(1)] ($/MWh)	Indexed Price ($/MWh)	Supply Period
San Juan	DisCos	2-A	68.1	100.6	109.04	2017 – 2031
	DisCos	2-C	40.8	100.6	109.04	2017 – 2031
	DisCos	3	272.5	103.2	111.83	2018 – 2032
Norvind	DisCos	4	45.5	113.2	122.66	2019 – 2033

(1) 2013-3 Second Call auction.

Currently, the regulated contracted energy is higher than the regulated consumed energy due to the regulated demand rate growth below the level projected by CNE for the auction processes. According to the CNE's report dated April 2021, the oversupply level in 2020 was 38.7%, with oversupply progressively decreasing by 2025. Consequently, the CNE modified the 2019/01 regulated auction process in order to move the supply start year from 2024 to 2026, and modified the schedule of the auction and the contracted energy level in a new process named 2021/01. Due to this oversupply situation, we have contracted the available energy left by the decreased DisCo consumption.

The following table summarizes signed PPAs and their general conditions with our Unregulated Customers, as of the date of this offering memorandum:

Company	Client	Beg. Date	End Date	Term	Price (USD/MWh)	Energy GWh/y	Indexed price 1Q2021
Norvind	Walmart	January 1, 2018	March 31, 2022	4 years + 3 months	50.5	14.4	54.20
Norvind	Agricovial	May 1, 2019	December 31, 2023	4 years + 8 months	53.5 (may-ago 2019), 50.0 (sep-dic 2019), 48.0 (2020 to 2023)	2.1	49.45
Norvind	Ceresita	May 1, 2019	December 31, 2023	4 years + 8 months	55.0 (may-ago 2019), 50.0 (sep-dic 2019), 49.0 (2020 to 2023)	5.5	50.19
Norvind	Contitech	October 1, 2019	December 31, 2023	4 years + 3 months	49.5	3.0	50.71
Norvind	Inmobiliaria Encomederos (DoubleTree by Hilton)	January 1, 2020	December 31, 2023	4 years	49.5	2.4	50.10
Norvind	PSA	October 1, 2020	September 30, 2024	4 years	42.00	0.9	42.08
Norvind	MN Agrícola Ltda	December 1, 2020	November 30, 2024	4 years	42.80	2.7	42.80
Norvind	Inversiones Punta Blanca	January 1, 2021	December 31, 2024	4 years	43.00	0.8	43.00
Norvind	Viñedos Familia Chadwick	April 1, 2021	March 31, 2025	4 years	45.00	3.6	45.00

Norvind	Minera Cerro Negro	January 1, 2022	December 31, 2025	4 years	42.13	40	N/A
Norvind	Universidad de Los Andes	April 1, 2022	March 1, 2026	4 years	40.00	16	N/A
Norvind	Inmobiliaria Jepsen Ltda. (Mall Boulevard Maipu)	January 1, 2021	December 31, 2024	4 years	42.00	3	42.00
Norvind	Viña Caliterra	April 1, 2021	March 31, 2025	4 years	45.00	1.5	45.00
Norvind	Importadora y Alimentos ICB Food Service	March 1, 2021	February 28, 2023	2 years	41.5	3	41.50
Norvind	Pacific Hydro Chacayes[(1)]	May 15, 2019	May 31, 2022	3 years	70.00	35	71.74
San Juan	Metro	April 19, 2016	March 31, 2032	16 years	95.00	Variable. 75.3 GWh average	102.18
San Juan	Enel Distribución	September 1, 2019	December 12, 2023	4 years + 4 months	52.5 (2019), 49.5 (2020), 48,0 (2021), 47,0 (2022 to 2023)	45 (2019), 150 (2020), 180 (2021 to 2023)	48.65
San Juan	Cinergia	April 1, 2021	March 31, 2025	4 years	41.00	20	41.00

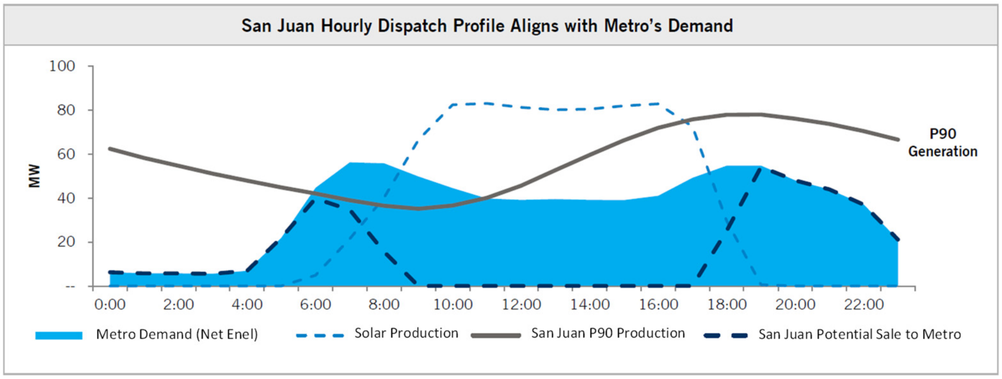
(1) See “*Energy Hedge Contract with Pacific Hydro Chacayes*” below.

Overview of the Metro PPA Agreement

San Juan entered into a PPA to supply Metro’s hourly consumption not supplied by its first and second priority suppliers (as further explained in the paragraph below) with additional energy it generates in excess of its DisCo PPAs. The offtake agreement with Metro is priced at \$95/MWh (October 2014 price) adjusted to U.S. CPI every six months. The Metro PPA contributes an additional annual average of 75.2 GWh of contracted generation through 2032.

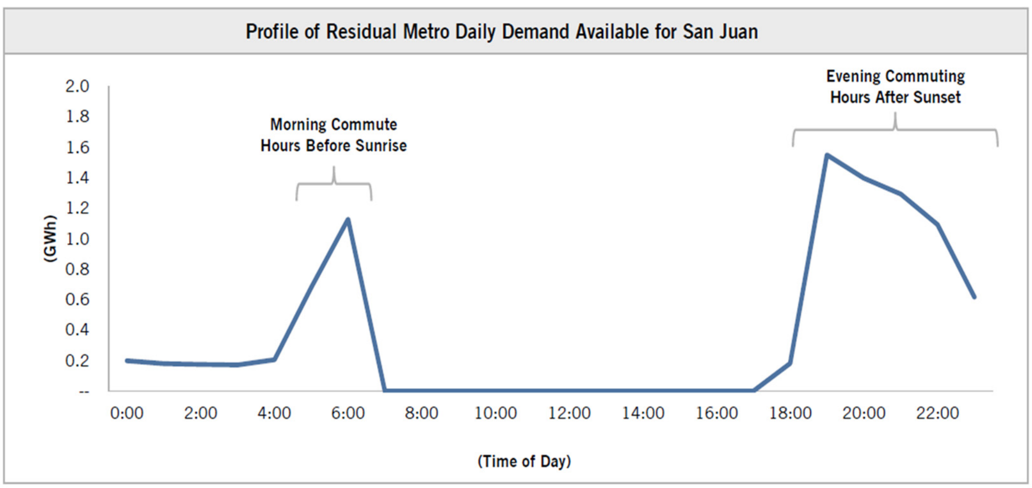
Metro receives electricity from two main parties, in order or priority, first, Enel Generación (40%), and second, El Pelícano solar company, prior to receiving contracted power from San Juan (potentially up to 60%). The Enel Generación and El Pelícano PPAs take priority over our Metro PPA, meaning that San Juan is contracted to supply Metro’s residual energy demand, but has no minimum capacity obligation under the terms of the contract. Moreover, despite being contractually third priority to supply Metro’s power, the dispatch profile associated with San Juan complements that of the El Pelícano solar plant; San Juan produces the majority of its energy at dawn and dusk when the solar supply alternative exits the market.

As demonstrated in the chart below, Metro’s average demand profile peaks during morning and evening passenger commuter hours and El Pelícano’s generation profile simultaneously declines during this timeframe. The decrease of solar energy from El Pelícano provides the opportunity for San Juan to meet the consistent daily need during the wind-heavy shoulder hours of Metro’s demand profile.



Source: ILAP.

The net result of (i) Metro's total demand, (ii) the 40% first priority supply from Enel Generación, and (iii) the second priority El Pelícano supply is a stable block of daily demand. The chart below illustrates the expected residual daily Metro demand available for San Juan to supply. Given the consistent nature of subway operations, this specific demand block is expected to be highly consistent on an annual basis.



Source: ILAP.

The generation that San Juan sells to Metro is surplus to its obligations and commitments to the DisCos under the tender process contracts, and as a result, the Metro PPA serves as a natural hedge against the risk of demand and supply mismatches in the DisCo tender processes. In the event that the DisCos have actual regulated customer load below contracted supply through the auction process, as it happened in 2020 and it is expected to occur in the next 4 years, San Juan can recover a portion of the unanticipated DisCo demand shortfall by selling the additional power to Metro under the bilateral PPA agreement. Under the terms of the Metro PPA, while San Juan has no commitment to supply any minimum quantity of power under the contract, Metro will purchase any excess power available up to 100% of their hourly demand. The Metro PPA provides counterparty diversity for San Juan and further reduces risk associated with spot market price fluctuations. San Juan also produces NCRE credits as a renewable energy generator, for which it charges Metro $5/MWh as part of the Metro PPA agreement.

A summary of the terms and conditions of the Metro PPA is set forth in the table below.

	Metro PPA with San Juan
Term	Sixteen (16) years.
Supply Term (P/Block)	April 19, 2016 - March 31, 2032.
Price	USD $95 /MWh
Indexation	CPI.
Quantity	Up to sixty percent (60%) of Metro's hourly consumption not supplied by solar priority suppliers, as well as supplemental power as may be requested by Metro from time to time and acquired by San Juan on a spot basis.
Quality Standards	All product delivered by San Juan under the Metro PPA shall meet the quality and security standards under applicable law.
Force Majeure	In addition to the force majeure events set forth under applicable law, the Agreement also considers other force majeure events such as any consumption restrictions implemented by a governmental authority. Proper notices shall be delivered by the party claiming force majeure pursuant to the times prescribed under the Metro PPA. Notwithstanding an event of force majeure, to the extent that there is power available to supply any supplemental power requirements of Metro, San Juan shall effectuate the supply in accordance with the Metro PPA.
Assignment	The Metro PPA may be assigned by either party upon the satisfaction of each of the following requirements: (i) the assignee becomes part of the Metro PPA, (ii) the assignee assumes the duties and obligations set forth under the Metro PPA, and (iii) the non-assigning party shall have consented to the assignment, which consent shall not be unreasonably withheld. Metro thereby consents to the assignment by San Juan to any affiliate (as defined therein) thereof so long as (i) the obligations under the Metro PPA are not materially affected, (ii) the maintains all rights with respect to the assets permitting the performance of the transactions contemplated by the Metro PPA, and (iii) the assignee does not incur any financial burden that risks performance under the Metro PPA.
Standard of Conduct	The parties acknowledge the application of applicable laws in connection with crimes for money laundering, terrorism financing, and bribing domestic and foreign government officials.
Amendments	Amendments to the Metro PPA shall be subject to the agreement of both Parties. To the extent that applicable laws are modified in a way that adversely affect the economics of the transactions contemplated under the Metro PPA, the affected party may request in writing the review and revision of the affected terms and conditions thereunder. Both parties shall negotiate in good faith for a period of one hundred and twenty (120) days the proposed amendment or modification of the Metro PPA. To the extent that the parties are unable to reach an agreement, the parties may submit the dispute to an arbitrator pursuant to the dispute resolution provisions of the Metro PPA. Any request for amendment or modification brought hereunder, shall be brought by the affected party no later than sixty (60) days following the implementation of the applicable law giving rise to the adverse economic impact, and such claim shall have an impact of at least USD $500,000.
Dispute Resolution	To the extent that any dispute arises between the parties, the parties shall settle the dispute by appointing a neutral arbitrator, or otherwise in accordance with applicable law.

Early Termination	Either party may terminate the PPA in the event of occurrence of any of the events contemplated hereunder, and upon providing prior written notice to the other party in accordance with the Metro PPA. a) Early Termination by Metro: i. Breach by San Juan of any of its supply obligations under the Metro PPA. ii. Breach by San Juan of certain material obligations under the Metro PPA, including with respect to quality, assignment, confidentiality, etc. iii. A liquidation of San Juan. iv. San Juan ceases to maintain the assets necessary to effectuate the transactions contemplated under the Metro PPA. v. If the San Juan Project experiences delays in its development stages, as further set forth under the Metro PPA. vi. If prior to the commercial operation date, Latin America Power S.A. ceases to control San Juan. b) Early Termination by San Juan: i. If Metro fails to make payment of two or more invoices, as further set forth under the Metro PPA. ii. Breach by Metro of certain material obligations under the Metro PPA, including with respect to assignment, confidentiality, etc. iii. A liquidation of Metro. c) Early Termination by Either Party: i. Force Majeure event persists for a period of more than one hundred and eighty (180) days. ii. In a twenty-four (24) month period, the hourly nodal difference is greater than or equal to USD $50 /MWh.

Overview of DisCo PPAs

In the context of the tender process, the CNE develops demand projections for the procurement of supply for Regulated Customers, based on each DisCos' projected requirements. See "*Legal and Regulatory Framework—Tender Process*." To reduce the risks and uncertainty associated with demand projections, the forecasts are updated annually. Despite these updates, the possibility still exists (particularly in the near-term) for actual energy demand from Regulated Customers to deviate from the forecasts used in the procurement of the PPAs. In the case that actual demand is below the contracted energy at a particular time (that is, the DisCos are over-contracted), the actual demand will be covered by all generators in proportion to their contracted energy. Therefore, the oversupply risk is distributed evenly (pro rata) across the generation market. According to the CNE's report dated April 2021, the oversupply level in 2020 was 38.7%, with oversupply progressively decreasing by 2025.

DisCos generate revenue by selling power to Regulated Customers at an officially determined tariff that is composed of three main components: (i) generation prices, (ii) transmission tolls, and (iii) the value added in distribution ("*VAD*"). See "*Industry—Business Segments—Distribution Segments*." In general, the generation component is a pass-through of the energy and capacity procurement costs incurred by the DisCo. The energy cost is estimated as the average energy price from the current long-term supply contracts (i.e. PPAs) awarded through the distribution tender processes, and the capacity price is a value administratively set by the CNE. Hence, the generation component of the tariff to Regulated Customers is basically the same price DisCos pay generators for their supply under their PPAs. The transmission component is also a pass-through of the trunk transmission and sub-transmission tolls incurred by the DisCo because these tolls are collected by the DisCos, and paid to the respective transmission companies.

However, unlike the generation and transmission components, the VAD represents an actual income to the DisCos and is calculated based on the average annualized distribution cost of an efficient (model) company under specified demand and supply conditions. See "*Industry—Business Segments—Distribution Segments—Compensation*." In simplest terms, it is calculated as the ratio between the total distribution costs and projected demand. Thus, if the demand projection used in determining a DisCo's VAD overstates actual demand, then the VAD will underestimate the DisCo's actual distribution costs, leading to revenue under-collection and lower margins. This risk of under-collection creates a strong incentive for DisCos to avoid overestimating their demand. Because this VAD component is independent of the actual costs of the DisCos, it incentivizes the DisCos to cut costs and project supply as close to reality as possible in order to meet the "model" company. The VAD therefore serves as an oversupply risk mitigant for the Chilean auction system.

A number of additional factors have also been implemented to mitigate the risk of DisCos over-contracting generation and subsequently apportioning PPA contracts down. Should the DisCos incorrectly project demand using inaccurate information in the process, the CNE has the authority to penalize the DisCos. Depending on the severity of the infraction, penalties could range from a monetary charge between US$830 and US$8.3 million, to closure and even to license cancellation.

The generation that San Juan sells to Metro and other clients is surplus to its obligations and commitments with the DisCo PPAs based upon a price determined under a tender process, and further, the Metro and other PPAs serve as a natural hedge against the risk of demand and supply mismatches in the DisCo tender processes. In the event that the DisCos have actual Regulated Customer load below supply contracted through the auction process, San Juan can recover a portion of the unanticipated DisCo demand shortfall by selling the additional power to Metro and others under bilateral PPA agreements.

As further described under "*Legal and Regulatory Framework—Tariff Stabilization Framework*," the Chilean government created the Tariff Stabilization Mechanism in November 2019, in order to reduce the costs of basic services, following the social unrest events occurred in Chile in October 2019. This mechanism temporarily stabilized electricity prices by rescinding a recent increase in electricity tariffs payable by Regulated Customers and contained in Tariff Decree No. 7T of 2019, while taking advantage of future reductions in energy prices payable by DisCos under PPAs that had already been awarded at lower prices, to ensure that generation companies would be made whole over time, maintaining the regulated tariff levels to May 2019 fixation. Additionally, the distribution and transmission tariffs were also fixed to May 2019 levels.

The Tariff Stabilization Framework defines a maximum value in Chilean currency that distributors may transfer to Regulated Customers, called PEC (*Precio Estabilizado a Clientes Regulados* in Spanish). The PEC is initially set at those price levels in Chilean currency established in the May 2019, a value that is fixed in Chilean currency during 2019 and 2020, and then adjusted for inflation index (CPI) from year 2021. The difference between the prices transferred to Regulated Customers and the price established in the contracts with the generators is temporarily assumed by the generation companies. Accrued amounts are gradually returned when new PPAs begin being supplied at lower values. The payment of the balances to the generators will be proportional to the balances due. The limit of uncollected balances cannot exceed US$1,350 million. Once this limit is reached, the tariff stabilization process will end, and these balances will be paid to the generation companies in the period 2025 to 2027. The deadline of accumulating uncollected balances corresponds to July 1, 2023. See "*Legal and Regulatory Framework—Tariff Stabilization Framework—PEC Receivables*."

A summary of the terms and conditions of the DisCo PPAs is set forth in the table below.

	San Juan	**Totoral**
Power Purchase Agreement	2013/03 Second Call Tender DisCo Power and Capacity Purchase Agreement Form.	
Scope	Each supplier shall sell to DisCos power and capacity during the entire supply period of the agreement.	
Term	Fifteen (15) years.	
Supply Term (P/Block)	Block 2-A: January 1, 2017 – December 31, 2031	Block 4: January 1, 2019 – December 31, 2033

	Block 2-C: January 1, 2017 – December 31, 2031 Block 3: January 1, 2018 – December 31, 2032
Price	In accordance with the tender offer made by Supplier, the DisCos shall pay the following prices for product to Supplier: a) Active Price: The price of active power shall be the USD \$/MWh price offered/awarded at the purchase price Polpaico 220 Kv (set forth above). b) Peak Hour Capacity: The price of capacity during peak hours shall be, for each purchase point, listed in the CNE's report named "Short-term node price index" (*Fijación de precios de nudo de corto plazo*). This price is charged to the customer as a "pass through" cost.
Indexation	U.S. CPI published by the Bureau of Labor Statistics of USA, and as further set forth under the applicable annex of the respective PPA.
Quantity	Total power invoiced by supplier every month to the DisCo on account of purchases for regulated customers at the purchase points shall be equal to the quantities actually demanded by the DisCo during the month of invoicing.
Quality Standards	All product delivered by supplier under a PPA shall meet the quality and security standards under applicable law.
Penalties	In the case of interruptions or suspensions to the supply of power, supplier shall reimburse the DisCo in proportion to the contracted supply.
Force Majeure	In addition to the force majeure events set forth under applicable law, the Agreement also considers other force majeure events such as: a) Any event originated by a third party, including a governmental authority, affecting the timely execution of the generation project associated with the PPA. b) Any delays in the commercial operation date of the transmission facilities awarded at the date of the tender offer that gave rise to the PPA, and only to the extent the generation project is suspended as a result thereof. If a force majeure event extends for a period in excess of twelve (12) months, the PPA may be terminated in accordance with its terms.
Assignment	A DisCo may assign its PPA, upon obtaining prior approval from CNE, to a parent, subsidiary, affiliate or related company that continues the business of the respective DisCo. Supplier may also assign the PPA, upon obtaining prior approval from CNE and the DisCo, to a parent, subsidiary or affiliate generation company provided the assignee assumes all terms and conditions of the tender offer that gave rise to such PPA and all the obligations established on the PPA. Supplier has the right to assign, encumber or pledge the PPA, in whole or in part, for the purpose of obtaining financing related directly to the construction or expansion of the Project or with the construction or expansion of generation units that may be required to ensure the supply contemplated therein. Supplier shall provide prior notice to the CNE and the DisCo regarding such assignment, encumbrance or pledge.
Standard of Conduct	The parties acknowledge the application of applicable laws in connection with crimes for money laundering, terrorism financing, and bribing domestic and foreign government officials.
Compliance with Laws	The PPA shall at all times be subject to and in compliance with applicable laws and regulations. In the event of any change that would render the PPA to not in compliance, the PPA shall be amended accordingly.
Dispute Resolution	To the extent that any dispute arises between the parties, the parties shall first attempt to settle the dispute amicably by appointing two representatives each to resolve the dispute. To the extent that the representatives are unable to resolve the dispute within twenty (20) days following the date of the first meeting, then the parties shall each

	elevate the matter to their upper management, who shall similarly attempt to resolve the dispute amicably. Thereafter, to the extent that the parties are unable to resolve the dispute following their third meeting of having attempted a resolution, either party may resort to submitting the dispute to arbitration. The arbitrator shall be mutually agreed to by the parties. The arbitration shall be governed pursuant to the Center for Arbitration and Mediation of the Chamber of Commerce of Santiago.
Early Termination	Either party may terminate the PPA in the event of occurrence of any of the events contemplated hereunder, and upon providing prior written notice to the other party and approval by the CNE. a) Early Termination by DisCo: i. Any breach of the PPA by supplier that is not cured within thirty (30) days of receipt of notice of such breach. ii. Expiration, revocation, cancellation or loss of any permits materially affecting supplier's ability to trade electricity. iii. Supplier obtains a credit rating below BB+, and does not strengthen it within six (6) months following supplier obtaining the BB+ credit rating. iv. Bankruptcy of supplier. v. Repeated material breaches by supplier of the PPA, upon prior approval of CNE, that is not cured within thirty (30) days of receipt of notice of such breach. b) Early Termination by supplier: i. Dissolution of the DisCo, unless to the extent the purpose of which is to merge or combine with another entity in the same line of business, so long as the resulting entity is able to comply with the obligations under the PPA. ii. Expiration, cancellation or forfeiture of the DisCo's electric distribution concession affecting the supply zone of the respective PPA. iii. Bankruptcy of the DisCo.

Overview of Capacity Market

The Chilean power market includes a capacity market for the recovery of generators' capital and fixed costs. The design is similar in concept to those of the U.S. Eastern Independent System Operators/Regional Transmission Organizations ("*ISOs/RTOs*"). As in the case of energy spot balance, capacity revenue is the result of a capacity spot balance (injected sufficiency capacity of power plants less capacity withdrawals) associated with PPAs. Prices are set based on the cost of new entry ("*CONE*") of a peaking unit and the relationship between capacity supply and demand. The differences for the Chilean market are: (1) the setting of price at CONE rather than net CONE (CONE less energy margin), which results in higher prices for a given capital cost, and (2) the apportionment of awards, rather than a sloped demand curve, which reduces volatility and maintains price nearer to CONE.

The CNE calculates capacity prices every six months, in January and July of each year. The latest publication in January 2021 posted prices of $7.86/kW-month and $7.28/kW-month at Nogales and Puerto Montt, respectively, which serve as representative nodes for the center-northern and southern subsystem, respectively. The Projects are located at center-northern subsystem. The market capacity prices have exhibited minimal volatility since market inception and the price consistency has made capacity revenues a reliable revenue stream for generators. For example, from 2013 onwards, prices have fluctuated narrowly between approximately $7.67 to $11.01/kW-month.

The amount of capacity that resources can sell is reflective of their output during peak demand conditions in the system. As a result, for intermittent power resources such as wind, capacity (MW) value is derated. For the San Juan Project, the sufficiency value is estimated to be in the range of 12.1% to 15.2% of nameplate capacity. For the Totoral Project, the sufficiency value is estimated to be in the range of 5.9% to 11.1% of nameplate capacity. Given these values and prevailing prices, both Projects would be expected to earn up to $4.5 million/year in consolidated capacity revenues. These values would be expected to increase over time with inflation and macroeconomic factors that drive the capital costs for combustion turbines.

Capacity payments are calculated as a function of the sufficiency capacity recognized to each power plant and the capacity price set by CNE. The current methodology used in Chile is the "sufficiency capacity" (in Spanish, *potencia de suficiencia*; formerly known as firm capacity), which was implemented in March 2016 through the Supreme Decree N°62, and further amendments modifying the procedures and the specific calculations for some generation technologies. In general, sufficiency capacity represents the ability of a power plant to provide power on an on-demand basis, and it is based on the theoretical maximum power that can be produced by a particular power plant, while adjusting for real planned and unplanned outage events (due to mechanical or fuel-related defects) and self consumption of energy.

The sufficiency capacity of generators is calculated based on their expected contribution to peak demand, which calculated ex-ante by the system operator, considering the expected contribution relates to the expected firm availability of each generating unit at the period of maximum demand, which relies on availability of the source of fuel used.

The sufficiency capacity calculation algorithm is made up of four stages. In the first stage, a verification of the maximum capacity is performed. The second stage determines the initial capacity, which depends on the generation technology (hydroelectric, thermoelectric, solar PV, wind, among others), and the availability of fuel or primary generation source, as well as the own consumption and maintenance statistics of each power plant. The third stage determines the preliminary sufficiency capacity, considering the forced unavailability factors. The fourth stage determines the definitive sufficiency capacity, by reducing the preliminary capacity with the demand adjustment factor, which is calculated of the sum of the preliminary sufficiency capacity of all the units of the system and the peak demand, defined as the average of the 52 highest hourly demands of the year.

NRCE Credits

The implementation of the NCRE Law in 2008 requires generation companies to demonstrate that a certain percentage of their total energy is being injected into the market via NCRE sources such as geothermal, wind, solar, biomass and small hydro facilities. The NCRE Law is highly beneficial to renewable generators like us. Generators lacking NRCE sources must contract with NRCE generation for a portion of their supply creating an additional stream of fixed revenue for wind generators.

NRCE supply obligations accounted for 5% of total electricity in 2015. In 2013, legislation passed (Law 20.698) supporting a renewable energy penetration target of 20% of total generation in Chile by 2025. Companies that do not comply with these targets are subject to fines for the generation difference in NRCE generation below the required amount on a per-megawatt hour basis. As of December 2020, Chile has already reached the NRCE quota established in Law 20.698 for 2025 year, registering a generation of around 24%.

Overview of Spot Market

Chile has a highly-regulated spot merchant market run by National Electrical Coordinator, the system operator, which coordinates the dispatch of generation assets in the marketplace. All generators provide their variable operational cost parameters to the National Electrical Coordinator, and in turn, it optimally dispatches the market minimizing total costs to the system. Since generators provide their full cost structure to National Electrical Coordinator, there is no "bidding" process.

Generators buy and sell energy from other generators in the real-time spot market. The market clearing price at each pricing node is called the Short Run Marginal Cost ("*SRMC*") or spot price, and it is the marginal cost of the last generator required to balance supply and demand, taking into account transmission constraints and losses. Neither DisCos nor large consumers are allowed to buy and sell energy on the spot market; only generators are allowed to trade in the spot market. Generators receive merchant spot market revenue as a result of the net value of energy injected (supplied) into the system less the energy withdrawn (demanded) into the system. The National Electrical Coordinator is responsible for conducting balancing analyses and overseeing the billing/payments on a monthly basis in order to ensure that generators receive the appropriate revenue for the supply they sell.

Our Projects are located in areas that have strong electricity demand. As a result, generated electricity is injected into the spot market at the point of generation (the Punta Colorada node for San Juan and the Las Palmas node for Totoral), and then withdrawn in accordance with our PPAs at the Polpaico node (indicative node for Santiago). As a result, we can be impacted by variations in the pricing differential between the injection and withdrawal nodes.

Equipment and Technology

San Juan Project

The table below provides details on the key equipment and technology of the San Juan Project. For further details, please refer to the Independent Engineers' Report included in this offering memorandum.

Description of San Juan Equipment

Wind Turbine Generators ("*WTG*")	56 Vestas V117-3.45 MW wind turbine generators (WTG), with a hub height of 91.5m, installed on shallow depth concrete gravity foundations (spread footings).
Blades	Vestas has a long track record successfully incorporating a similar blade technology to the one implemented in the San Juan V117-3.45MW turbines. The blade used for the V117-3.45 MW is an extension of the V112-3.0MW blade, modified at the root. The V117-3.45 MW is equipped with a 117-meter diameter rotor consisting of three blades and a hub. The blades are controlled by the microprocessor pitch control system OptiTip. Based on the prevailing wind conditions, the blades are continuously positioned to optimize the pitch angle. The blades are made of carbon and fiberglass and consist of two airfoil shells bonded to a supporting beam.
Gearbox	The gearbox design from Winergy is conventional, having two planetary stages followed by one parallel stage. The thoroughness of the gearbox test program at Vestas' world leading facilities at Århus is an important mitigation of gearbox risk. The test of the gearbox for the new 3 MW Platform turbines is ongoing but not completed. However, the modifications made to the 3.45 MW gearbox compared to the 3.0 MW are minor.
Hub / Pitch System	The design of the hub and pitch system for the V117-3.45 MW turbines is similar to the V112-3.0 MW. However, Vestas has performed some structural strengthening. A new control of the pitch speed during emergency stop called OptiStopTM has been introduced to reduce the loading. Each pitch system consists of a hydraulic cylinder mounted to the hub and a piston rod mounted to the blade via a torque arm shaft. Valves facilitating operation of the pitch cylinder are installed on a pitch block bolted directly onto the cylinder.
Generator	The new 3.45 MW platform turbines utilize an asynchronous generator.
Converter	Vestas switched to a full-scale converter for the V112-3.0 MW turbine and is keeping to this approach for the new 3 MW platform turbines. This brings significant overall advantages to the operation of the turbine, particularly in terms of grid code compliance and reduced loads on the drive train.
WTG Transformer	Dry transformer mounted in an isolated area at the back of the nacelle.
Towers	The tower to be used on the project in question is tubular steel, in accordance with the industry standard.

Yaw Systems	The new 3 MW platform turbines yaw system is identical to the yaw system of the V112-3.0 MW. The concept is based on friction pads bearings.
Foundations	Two types of foundations for the wind turbines with diameters of 18.5m and 19.0m, with durability that can sustain repetitive loads for at least 30 years without suffering issues of fatigue of the concrete or reinforcement bars.
220kV Substation	A single 33/220 kV windfarm substation - San Juan substation (SJS) - collects the electricity generated by the turbines and increases the voltage for export to the transmission system.
Substation Transformers	Two transformers 33/220 kV installed in the San Juan substation, each of which is capable of delivering 110 MVA, which allows to effectively eliminate any risk of full power loss. Medium-voltage (MV) collection systems of twelve 33 kV circuits connect the WTGs to the substation.
Interconnection	The Project is connected to the Punta Colorada substation through an 85.7 km, 220 kV, overhead line (OHL).
Power Plus Upgrade	During 2017 a power upgrade agreement was signed with Vestas in order to increase the energy production per turbine from 3.3 MW to 3.45 MW, increasing therefore the installed capacity from 184.8 MW to 193.2 MW. This increase on the maximum power production was approved by the System Operator in May 2019.

Totoral Project

The table below provides details on the key equipment and technology of the Totoral Project. For further details, please refer to the Independent Engineers' Report included in this offering memorandum.

Description of Totoral Equipment

Wind Turbine Generators ("*WTG*")	23 Vestas V90-2.0 MW wind turbine generators (WTG), with a hub height of 80.0m
Blades	The blades are made of fiber glass reinforced epoxy and carbon fibers. Each blade consists of an inner beam encircled by two shells. The blades are designed for optimized output and minimized noise and light reflection. The V90 blade design minimizes the mechanical loads applied to the turbine. The blade bearing is a double raced 4-point ball bearing bolted to the blade hub. Each blade has a lightning protection system consisting of lightning receptors on the blade tip and a copper wire conductor inside the blade.
Gearbox	The main gear transmits the torque from the rotor to the generator. The gear unit is a combination of a 2-stage planetary gear and a 1-stage helical gear. The gear housing is bolted to the bedplate. The low speed input shaft is bolted directly to the hub without the use of a traditional main shaft. The gearbox lubrication system is a forced feed system without the use of an integrated oil sump.
Hub / Pitch System	The energy input from the wind to the turbine is adjusted by pitching the blades according to the control strategy. The pitch system also works as the primary brake system by pitching the blades out of the wind. This causes the rotor to idle. Double-row four-point contact ball bearings are used to connect the blades to the hub. The pitch system relies on hydraulics and uses a cylinder to pitch each blade. Hydraulic power is supplied to the cylinder from the hydraulic power unit in the nacelle through the main gearbox and the main shaft via a rotating transfer. Hydraulic accumulators inside the rotor hub ensure sufficient power to pitch the turbine in case of failure.

Generator	The generator is an asynchronous 4-pole generator with a wound rotor. Variable speed allows varying the rotor speed within a wide speed range. This reduces power fluctuations in the power grid system as well as minimizes the loads on vital parts of the turbine. Furthermore, the variable speed system optimizes the power production, especially at low wind speeds. The generator is water-cooled.
Converter	The converter controls the energy conversion in the generator. The VCS converter feeds power from the grid into the generator rotor at sub-sync speed.
WTG Transformer	The transformer is located in a separate locked room in the nacelle with surge arresters mounted on the high-voltage side of the transformer. The transformer is a two-winding, three-phase, dry type transformer. The windings are Delta connected on the high-voltage side unless otherwise specified. The low-voltage windings have a voltage of 690 V and a tapping at 480 V and are Star-connected. The 690 V and 480 V systems in the nacelle are TN-systems, which means the star point is connected to earth.
Towers	The tower to be used on the project in question is tubular steel, in accordance with the industry standard.
Yaw Systems	The V90 turbines yaw system is based on friction pads bearings and was subsequently adopted for the V112-3.0 MW.
Foundations	Totoral has 14.5m square cement turbines with varying depths of 1.6m to 2.5m. The durability has been assessed and the turbines can sustain repetitive loads for at least 30 years without suffering issues of fatigue of the concrete or reinforcement bars.
66kV Substation	Medium voltage cables connect the wind turbines to the 23/66 kV substation located within the windfarm area.
Substation Transformers	One transformer on substation, which is capable of delivering the 220 kV export voltage to effectively eliminate any risk of full power loss.
Interconnection	A 7-km transmission line links the 23/66Kv substation to the 66/220 kV transmission network.

Project Sites

San Juan Project

The San Juan Project is located in Vallenar, Region of Atacama, Chile (approximately 650 Km north of Santiago). San Juan holds ownership, lease and easement rights with respect to different areas of the land where the buildings and infrastructure of the San Juan Project is emplaced.

Own Land

San Juan holds ownership title over land “Lote 19”, of 80 hectares approximately, and land “Lote 20”, of 16 hectares approximately. Such property was acquired under purchase agreements executed by public deeds in 2015. The land is registered under San Juan’s name before the competent real estate registrar.

Leased Land

San Juan entered into a long-term land lease agreement in 2010 with a non-related third party (Agrícola Konavle Limitada), for the benefit of the San Juan Project. The leased area extends to approximately 2,900 hectares. The lease agreement has a 30 year-term from the date of full commercial operation (March 2017), and the rent payable by San Juan consists in 4% of the total revenue of San Juan, with a minimum guaranteed amount of US$5,200 per each MW of installed capacity. San Juan may early terminate the agreement if: (i) permits for the operation of the San Juan Project are revoked or the interconnection point with the main grid; (ii) if San Juan concludes that the San Juan

Project is no longer economically feasible; and (iii) breach of tenant's obligations. The tenant may early terminate the agreement in case of breach by San Juan (with a one-month cure period). Tenant is subject to the prohibition to sell, mortgage, lease or subdivide the leased property.

Easements

San Juan Project holds titles for electrical easements granted by public deed agreements entered into with several landowners in connection with the transmission line. These agreements grant an *in rem* right (*derecho real*) over the land for an indefinite -or 30-year renewable- term.

Totoral Project

The Totoral Project is located in Canela, Region of Coquimbo, Chile (approximately 300 Km north of Santiago). Norvind holds ownership and easement rights with respect to different areas of the land where the buildings and infrastructure of the Totoral Project is emplaced.

Own Land

Norvind holds ownership title over land "Lote A Uno B," of approximately 1,049.76 hectares. This property was acquired under a purchase agreement in 2008. The land is registered under Norvind's name before the competent real estate registrar.

Easements

The Totoral Project holds titles for electrical easements granted by public deed agreements entered into with several landowners in connection with the transmission line. These agreements grant an *in rem* right (*derecho real*) over the land for an indefinite -or 40-year renewable- term.

Operations and Maintenance

O&M Strategy

The O&M Agreements ensure the full productivity and long-term performance of the wind turbines. The operations and maintenance strategy for the San Juan and Totoral Projects is built around original equipment manufacturer maintenance solutions. The O&M Agreements cover substantially all of the operation and maintenance costs, subject to certain exceptions, and effectively transfers the maintenance cost risk to Vestas, who has a long-standing history and experience with operating and maintaining wind turbines and is well positioned to manage the responsibilities thereof effectively. Under the O&M Agreements, Vestas will also provide repairs and replace parts of the turbines in the event of failures, thus ensuring the full productivity and long-term functionality of the wind turbines that comprise the Projects.

In addition, Vestas offers a life extension program as part of their operation and maintenance services. Vestas offers this service, typically on or around the 15th to the 20th year of operation mark, subject to detailed inspections, assessments and testings of certain key components. In the case of the San Juan and Totoral Projects, respectively, we plan to undertake the asset life extension study on or around the year 2033 and 2026, respectively, and implement any additional recommended corrective and preventative maintenance measures required.

Further to the services provided under the O&M Agreements, we have also instituted independent site maintenance and management personnel with a 24/7 control room. The control room is located at our headquarters in Santiago, Chile, thus enabling highly qualified engineers and technicians to proactively troubleshoot challenges that may arise by providing real time oversight, supervision and monitoring capabilities for all generating units at both Projects.

The operation and maintenance of other assets, excluding the wind turbines and towers, has been outsourced to local contractors who are used to support lower risk items, including building maintenance, estate management, and substation maintenance.

Useful Life of Vestas

Wind farms are a relatively new technology when compared to regular thermic-based energy generators. There is not enough evidence in the market to assess the exact useful life of a wind turbine, especially in a highly dynamic market where machines are being constructed with better materials and designs, and where solutions and secondary markets develop and complements the primary turbine production market, making it affordable to keep operating continuously over time.

According to Vestas -our turbine provider and current O&M contractor– the expected useful life of the wind turbines for both of our Projects is up to 30 years, provided a proper and adequate maintenance plan is in place. The remaining useful life for the San Juan Project is 25 years and the remaining useful life for the Totoral Project is 20 years.

O&M Agreements

Under the Service and Availability Agreement between San Juan and Vestas dated March 25, 2015, as amended on January 29, 2021 (the "*San Juan O&M Agreement*"), and the Service and Availability Agreement between Norvind and Vestas dated April 1, 2013, as amended on December 14, 2016 (the "*Totoral O&M Agreement*," and together with the San Juan O&M Agreement, the "*O&M Agreements*"), Vestas is responsible for the operation and maintenance of the San Juan Project and Totoral Project. The terms of the O&M Agreements with Vestas guarantee generation availability of 97% per turbine in both Projects, and 98% with respect to the San Juan Project starting 2022. As of this date, availability per turbine has remained above the guaranteed level in both Projects; therefore, the Company has not received any compensation for losses.

A summary of the O&M Agreements is set forth in the table below.

	San Juan	**Totoral**
Term	Twenty (20) years (extended through March 2037)	Twenty (20) years (extended through March 2029)
Scope	The scope of the services of Vesta under the O&M Agreements, includes the provision of (i) operation services, including the real-time monitoring and control of the wind turbines, (ii) scheduled and unscheduled maintenance, (iii) consumables, spare parts, tools and other equipment necessary for the operation of the San Juan and Totoral Projects, (iv) monthly performance and fault reports, (v) software updates to control and monitoring systems, (vi) remote surveillance, among other services. Other additional services may be provided by Vestas and subject to costs not otherwise contemplated within the scope of the O&M Agreements.	
Price	An annual base fee, per wind turbine, for each Production Period (as defined below), payable in advance in equal quarterly installments, as follows: Year 1 – 5: US$63,000 as upwardly adjusted pursuant to price indexation formula. Year 6 – 10: US$64,900 as upwardly adjusted pursuant to price indexation formula. Year 11 – 15: US$71,900 as upwardly adjusted pursuant to price indexation formula.	An annual base fee per wind turbine per year, payable in advance in equal quarterly installments, as follows: Year 2016 – 2019: US$26,000 as upwardly adjusted pursuant to price indexation formula. Year 2020 – 2024: US$42,500 as upwardly adjusted pursuant to price indexation formula. Year 2025 – 2029: US$45,600 as upwardly adjusted pursuant to price indexation formula.

	Year 16 – 20: US$82,900 as upwardly adjusted pursuant to price indexation formula.	
Production Periods	Means, as applicable the first Production Period which begins on the commencement date and continues for a period of twelve (12) months thereafter, or any of the subsequent Production Periods, each of which begins on the day after the expiration of the first Production Period, or anniversary thereof, and for the first five (5) years of the term, continues for a period of twelve (12) months, and thereof each Production Period continues for a period of twenty-four (24) months thereafter, provided, however that the final Production Period shall end on the last day of the term.	Means, as applicable, the first Production Period which begins on the commencement date and continues for a period of twelve (12) months thereafter, or any of the subsequent Production Periods, each of which begins on the day after the expiration of the first Production Period, or an anniversary thereof, and continues for a period of twelve (12) months thereafter, provided, however that the final Production Period shall end on March 31, 2029.
Parent Company Guarantee	As security for the correct and timely performance of Vestas' obligations under the San Juan O&M Agreement, the parent company of Vestas executed, on March 31, 2015, a Parent Company Guarantee.	
Availability Warranty (per turbine)	Vestas guarantees and agrees to meet or surpass the availability warranty, which for purposes of the San Juan O&M Agreement shall be: For the 1st Production Period: 95% For the 2nd Production Period: 97% For subsequent Production Periods: 98%	Vestas guarantees and agrees to meet or surpass the availability warrant for each Production Period, which for purposes of the Norvind O&M Agreement shall be: 97%.
Force Majeure	Article 45 of Chilean Civil Code applies. Further, the O&M Agreements also consider force majeure to be: (i) Natural disasters, and acts of god, as further described therein; (ii) Man-made disturbances, including war or other armed conflict, civil disturbance, as further described therein; (iii) Governmental actions, as further described therein; (iv) Closing of or congestion in any harbor, dock, port, canal or other adjunct of the shipping or navigation, as further described therein; (v) Findings of burial grounds, fossils, archaeological or religious sites.	
Early Termination	Generally, termination by Vestas for San Juan's: (i) Failure to satisfy payment obligations under such O&M Agreement, and failure to cure within twenty (20) business days of receipt of notice of breach thereof; (ii) Cessation or threat to cease activities in connection with such O&M Agreement; (iii) Insolvency or similar bankruptcy or reorganization procedure; (iv) Liquidation; (v) Assignment of such O&M Agreement not in accordance with the terms thereof; (vi) Termination by Vestas of that certain Supply Agreement entered into between the parties; (vii) Breach of its representations and warranties thereunder; and (viii) Failure to perform material obligations, and failure to cure	Generally, termination by Vestas for Norvind's: (i) Failure of to satisfy material obligations under such O&M Agreement, and failure to cure within thirty (30) business days of receipt of notice of breach thereof; (ii) Failure to satisfy its payment obligations under such O&M Agreement, and failure to cure within fifteen (15) business days of receipt of notice of breach thereof; (iii) Cessation or threat to cease activities in connection with such O&M Agreement; (iv) Insolvency or similar bankruptcy or reorganization procedure; (v) Liquidation; (vi) Assignment of such O&M Agreement not in accordance with the terms thereof; and (vii) otherwise in

	within eighty (80) days of receipt of notice of breach thereof. Generally, termination by San Juan for Vesta's: (i) Failure to perform material obligations, and failure to cure within eighty (80) days of receipt of notice of breach thereof; (ii) Amount of penalties for breach of availability warranty payable by Vestas under such O&M Agreement exceeding the limits set forth therein; (iii) Cessation or threat to cease activities in connection with such O&M Agreement; (iv) Insolvency or similar bankruptcy or reorganization procedure, including with respect to Vesta's parent company; (v) Liquidation; (vi) Assignment of such O&M Agreement not in accordance with the terms thereof; (vii) Breach of its representations and warranties thereunder; (viii) Termination of that certain Supply Agreement entered into between the parties for breach by Vestas.	accordance with the Norvind O&M Agreement. Generally, termination by Norvind for Vesta's: (i) Failure of to satisfy payment obligations under such O&M Agreement, and failure to cure within thirty (30) business days (but in no event more than eighty (80) business days) of receipt of notice of breach thereof; (ii) Cessation or threat to cease activities in connection with such O&M Agreement; (iii) Abandonment of the park, or plain demonstration of its intent not to continue performance thereunder; (iv) Insolvency or similar bankruptcy or reorganization procedure; (v) Liquidation; (vi) Assignment of such O&M Agreement not in accordance with the terms thereof; (vii) or otherwise in accordance with the Norvind O&M Agreement. Norvind may also terminate this O&M Agreement without cause or justification upon providing prior notice to Vestas at least ninety (90) days prior to the proposed termination date. The parties to the Norvind O&M Agreement can terminate the same for convenience in the case they agree and execute the terms and conditions of a AOM 5000 services agreement that will replace such agreement.
Liability Limitations	Vestas' liability is limited to 100% of the service fees paid by San Juan in connection with the San Juan O&M Agreement. Notwithstanding the foregoing, Vestas' liability with respect to the availability warranty is limited, with respect to any Production Period, to USD $3,750,000. Neither Party shall be liable to the other party for any loss of profit, loss of use, loss of production, loss of contracts, loss of permits, financial costs, loss of tax credits or subsidies or for any indirect loss that may be suffered by the other party. The amounts paid by insurance companies under insurance required thereunder shall not be considered for purposes of reaching the liability limitation set forth therein. Furthermore, limitations of liability shall not apply regarding "responsabilidad	Vestas' liability is limited to 50% of the service fees paid by Norvind in connection with the Norvind O&M Agreement, other than in the case of gross negligence or willful misconduct in which case no liability limitation shall apply. Notwithstanding the foregoing, Vestas' liability with respect to the availability warranty is limited, with respect to any Production Period, to an amount equal to the fees payable to Vestas for such Production Period. Neither Party shall be liable to the other party for any loss of profit, loss of use, loss of production, loss of contracts, loss of permits, financial costs, loss of tax credits or subsidies or for any indirect loss that may be suffered by the other party. All liability of Vestas shall expire at the end of the term and any claims against Vestas arising from the Norvind O&M Agreement shall be submitted before the

	extracontractual" liability under applicable law. All liability regarding indemnity and confidentiality obligations of the parties thereunder shall expire five (5) years as of the end of the defect notification period. Subject to the foregoing, all liability of Vestas shall expire at the end of the term.	end of the term or otherwise such claims are invalid.
Dispute Resolution	The parties shall first amicably attempt to resolve any dispute that may arise within twenty-five (25) business days of receipt of notice of the existence of the dispute. Thereafter, if the parties are unable to settle the dispute, the dispute shall be submitted to arbitration in accordance with the Rules of Arbitration Procedure of the Santiago Arbitration and Mediation Center of the Santiago Chamber of Commerce, as further set forth under the San Juan O&M Agreement.	The parties shall first amicably attempt to resolve any dispute that may arise within thirty (30) days of receipt of notice of the existence of the dispute. Thereafter, if the parties are unable to settle the dispute, the dispute shall be referred to a committee comprised by members of both parties. If the dispute is unable to be resolved within the times prescribed therein, it shall be submitted to arbitration in accordance with the Rules of Arbitration Procedure of the Santiago Arbitration and Mediation Center of the Santiago Chamber of Commerce, as further set forth under the Norvind O&M Agreement.
Assignment	Consent required for the assignment of the San Juan O&M Agreement to another third party; provided that San Juan may assign this agreement as security in favor of a lender upon providing notice to Vestas. Vestas may assign the agreement to a member of its group upon providing thirty (30) days prior notice to San Juan; provider further that the Vestas parent guaranty remains in full force and effect, and all agreements signed by Vestas and lender be assigned to and executed by the relevant third party. A change in control (as defined therein) of San Juan constitutes an assignment under this agreement.	Consent required for the assignment of the Norvind O&M Agreement to another third party; provided that either party may assign this agreement as security in favor of a lender upon providing notice to the other party; provided further that Norvind may assign the agreement to any party who is not a competitor (as defined therein). Further, Vestas may assign the agreement to its parent or a party controlled by its parent. A change in control (as defined therein) of Norvind constitutes an assignment under this agreement.

Relevant Repairs

During 2020, a zigzag transformer overheat event occurred in the San Juan Project, damaging it and forcing us to limit the capacity of the wind farm to 50%. Zigzag transformers are part a security system installed to protect the main power transformers from suffering damage, and was part of the protective design of the Project's substation consisting in two circuits, two main transformers and two zigzag transformers. Even though the Project could still have used the main transformer without the zigzag protection, we decided to generate with only one power transformer, which limited generation to that transformer's capacity. The potential failure was controlled by the protection system of the San Juan Project, properly operating to avoid major damages on the power transformer.

In order to prevent a new extended stoppage event, our O&M team executed a plan including the purchase of a spare zigzag transformer, currently available in the substation site, to ensure a quick repair/exchange in case a new replacement is needed. Also, the MV cables configuration was modified, increasing the asset reliability from the incomers to the LV side of the transformer. Also, the O&M team executes weekly thermography inspections allowing to make statistic behavior analysis of the temperatures of the MV and HV installations.

We estimate that losses related to this malfunction were US$191,811 in connection with repairs and US$768,717 in connection with lost profits. Losses were covered by our insurance, with a US$100,000 deductible for costs associated with repairs and a 30-day deductible associated with lost profits.

Interconnection and Interconnection Maintenance Agreement

Geographically, Chile is a long, thin country that extends 4,270 km (approximately 2,653 miles) from north to south, making it relatively expensive to connect the majority of the country. The transmission system in Chile is a key factor impacting the long-term locational marginal price forecast in the SEN.

The San Juan Project is connected to the grid at the Punta Colorada substation via an 85km transmission line at 220 kV. The Totoral Project also sells power into the SEN, and is connected to the grid at the Las Palmas substation via a 7 km transmission line at 220 kV. The Punta Colorada and Las Palmas substations are owned by Transelec. In connection with the foregoing, the San Juan and Totoral Projects have entered into agreements with Transelec for the interconnection of the Projects, a general summary of which has been included below.

	San Juan	**Totoral**
Agreement	Operations Agreement dated April 27, 2016 between San Juan and Transelec.	Operations Agreement dated November 5, 2009 between Norvind and Transelec.
Term	The term of the Agreement shall continue for so long as the interconnection remains in effect.	The term of the Agreement shall continue for so long as the interconnection remains in effect.
Scope	Interconnection of the San Juan Project to the grid at the Punta Colorada substation via an 85km transmission line at 220 kV.	Interconnection of the San Juan Project to Transelec's transmission system.
Liability	Transelec will not be responsible for the transient deterioration of the electrical variables; grid frequency and bus voltage, which are controlled by the National Electric Coordinator. The parties acknowledge that in case of damages thereunder, such will not include indirect damages, loss of profits or moral damages.	Norvind shall be liable for damages suffered by persons, facilities and/or equipment of Transelec or its customers as a result of any culpable or willful acts of Norvind, its personnel or personnel of its contractors or subcontractors. Transelec will not be responsible for accidents, damages or material or personal damages that may be suffered by Norvind, its personnel and/or others, or to their equipment and facilities, by actions of third parties and technical failures that are not otherwise attributable to Transelec or any of its other customers, as well as for any force majeure events. Norvind releases and undertakes to release Transelec from all liability for damages of any nature that may affect persons and/or its own property or that of third parties, as a consequence of an action of Norvind or its personnel. Norvind will be exclusively liable to Transelec with respect to the activities and operations that it requests or must

		carry out in connection with this agreement. Transelec shall not be liable for transient deterioration of electrical variables, grid frequency and bus voltage.
Assignment	Either party may assign the Agreement upon obtaining prior written consent of the other party, which consent shall not be unreasonably withheld. All assignments are conditioned on the assignee possessing an ability to abide by the terms and conditions of the Agreement, and upon the assumption of the matters contemplated therein.	Either party may assign the Agreement upon obtaining prior written consent of the other party, which consent shall not be unreasonably withheld. All assignments are conditioned on the assignee possessing an ability to abide by the terms and conditions of the Agreement, and upon the assumption of the matters contemplated therein.
Dispute Resolution	Any and all disputes shall be submitted to arbitration, which shall be subject to the Rules of Arbitration Procedure of the Santiago Arbitration and Mediation Center of the Santiago Chamber of Commerce.	Any and all disputes shall be submitted to a Experts Panel (as defined under Title VI of the DFL No4/2006), which dispute must be submitted within thirty (30) calendar days after a party requests to the other the resolution of such dispute before the Panel of Experts. To the extent the Panel of Experts is not competent to handle such dispute, the dispute shall be submitted to arbitration, which arbitrator shall be mutually agreed upon by the parties, or the extent a disagreement ensues, by the Santiago Chamber of Commerce A.G.
Early Termination	To the extent that San Juan fails to satisfy certain obligations under the agreement, including with respect to environmental compliance and security, Transelec shall have the right to request termination of the agreement.	--
Other	In addition to this agreement, the parties have also entered into the following agreements, among others, that cover different aspects pertaining to the Project and its respective interconnection: a) Agreement for the Connection to Transelec's Transmission System, dated February 28, 2014, as amended on January 28, 2015. b) Agreement for Use of Common Facilities dated April 27, 2016. c) Services Agreement dated April 29, 2015, as amended on October 4, 2016.	In addition to this agreement, the parties have also entered into the following agreements, among others, that cover different aspects pertaining to the Project and its respective interconnection: a) Purchase Agreement for Payment of Investment of Complementary Facilities of the Paño de Conexión dated May 11, 2009, by means of public deed granted before the Notary Public of Santiago Mrs. María Gloria Acharán Toledo. Amended by public deed dated June 28, 2013, granted before the Notary of Santiago Mrs. María Gloria Acharán Toledo. b) Technical Operation and Maintenance Services Agreement dated April 28, 2009. c) Payment Agreement for the Use of Transmission Facilities in Canela Substation for the

Connection of the Parque Eólico Totoral to the SIC dated May 8, 2009, granted before the Notary Public of Santiago Mrs. María Gloria Acharán Toledo. Amended by public deed dated June 28, 2013, granted before the Notary of Santiago Mrs. María Gloria Acharán Toledo.

d) Tolling Agreement for Injection Facilities in Canela Substation dated April 28, 2009.

e) Purchase and Sale Agreement dated October 28, 2011, granted before the Notary of Santiago Mrs. Maria Gloria Acharán Toledo.

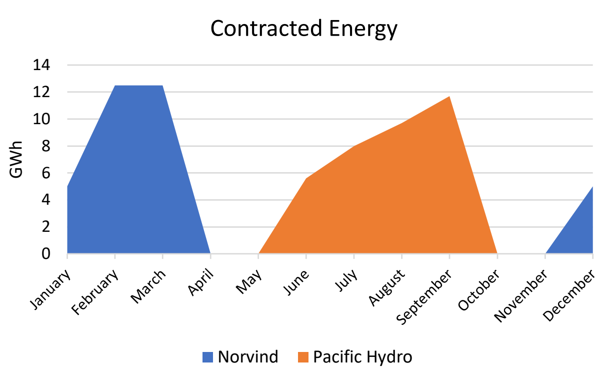
f) Payment Agreement dated October 3, 2016.

g) Services Agreement dated September 6, 2016.

On April 28, 2009, Norvind entered into an interconnection maintenance agreement with Transelec (the "*Interconnection O&M Agremeent*") which provides for the operation and maintenance at the Las Palmas substation in consideration of a fixed annual fee of UF 1.265,8 (plus value added taxes), to be paid proportionately in monthly installments. The Interconnection O&M Agreement has an initial term of five (5) years, with successive five (5) year terms unless otherwise terminated by either party upon providing three (3) month notice. The Interconnection O&M Agreement also provides for early termination by either party thereto. Norvind may terminate the Interconnection O&M Agreement upon providing Transelec with six (6) months prior written notice, and Transelec may terminate the Interconnection O&M Agreement upon providing Norvind with one (1) year prior written notice. To the extent that Transelec elects to terminate the Interconnection O&M Agreement, there are several credible firms available to assume the role of interconnection O&M provider and maintain the substation. The payment for the use of the facilities is active through April 2023.

Energy Hedge Contract with Pacific Hydro Chacayes

Norvind and Pacific Hydro Chacayes signed a power purchase agreement in which Norvind sells energy to Pacific Hydro Chacayes during the winter months (June to September) and Pacific Hydro Chacayes sells energy to Norvind during the summer months (December to March). The annual contracted energy for both companies is 35 GWh, therefore working as a hedge mechanism for spot market variations given that there is no net positive or negative balance after the corresponding period. The following figure generally depicts the levels of energy contracted by month established under the contract.



Source: ILAP.

Chilean regulation states that this kind of contracts between two generation companies are not subject to market obligation payments, such as capacity, transmission and ancillary services charges, among others. Thus, the contract only establishes an energy price of US$70 MWh at January 2019 prices, adjusted monthly with CPI. This contract is valid until May 2022.

Insurance

Both Projects have insurance coverages that are in line with those of similar assets and industry standards, adequate to properly mitigate for the operational risks of the Projects. In general, our coverage includes:

Line of Coverage	Estimated Annual Exposure	Limits	Coverage	Retention
Property Damage & Business Interruption (PD/BI) San Juan (SJU)	PD: US$338,985,435 BI: US$40,885,662 Total: US$379,871,097	Limit of liability: FULL VALUE but US$100,000,000 each and every loss, combined single limit for property damage and business interruption but in the aggregate with respect to Earthquake, Tsunami and Volcanic Eruption. PI: 18 months.		10% of the loss minimum US$100,000 each and every loss for all the events except for: 2% of Total Insured Value with a minimum of US$6.770,000 each and every loss with respect to Earthquake, Tsunami and Volcanic Eruption and flood Business Interruption: 30 days each and every loss.
Property Damage & Business Interruption (PD/BI) Norvind (TOT)	PD: US$132,272,681 BI: US$10,192,764 Total: US$142,465,445	Limit of liability: FULL VALUE but US$25,000,000 each and every loss, combined single limit for property damage and business interruption but in the aggregate with respect to Earthquake, Tsunami and Volcanic Eruption. PI: 18 months.		10% of the loss minimum US$100,000 each and every loss for all the events except for: 2% of Total Insured Value with a minimum of US$2,645,000 each and every loss with respect to Earthquake, Tsunami and Volcanic Eruption 30 days in respect of business interruption.
D&O (Directors' and Officers' Liability)		US$ 5,000,000 per event and in the annual aggregate.	Directors and Officers.	No deductibles.
General Liability (GL)		US$ 30,000,000 per occurrence and in the annual aggregate.	General liability including Premises & Operations, Employer's and other extensions.	General: US$5,000 Except: - Vehicles: US$25,000 - Employers Liab. (Patronal): US$25,000
Terrorism		US$25,000,000 each and every loss, combined single limit for property damage and business	Sabotage and Terrorism, and Business Interruption resulting therefrom.	Property Damage: 10% minimum US$25.000 each and every occurrence

	interruption for all the locations.	Business Interruption and Contingent Business Interruption: 5 days.

In addition, we are party to a prevention of occupational hazard adhesion agreement with Mutual de Seguridad, major Chilean occupational health and safety institution, at LAP Chile level, through which LAP receive technical support in prevention measures. The agreement also includes insurance against work accidents and occupational diseases.

The insurance companies and ratings of each of the current insurance providers are listed below:

Type / Line	Insurer	Local Rating
Property Damage & Business Interruption (PD/BI)	Starr Chile Insurance Company	AA- (Feller Rate)
General Liability (GL)	Unnio Chile Seguros Generales S.A,	BB- (Humphreys)
Terrorism	Orion Seguros Generales S.A.	A+ (Feller Rate)
D&O	Southbridge Compañía de Seguros Generales	AA+ (Feller Rate)

Competition

Due to the entry of new power plants and generation companies during the last five years, either to sell energy in the PPA or spot markets, both have registered lower prices, reflecting that the installed capacity is growing to a higher rate than the demand. We have adapted to this situation by offering to our potential and current clients energy prices at competitive levels, aiming to maintain our level of contracted energy. This way, we have signed new PPAs throughout the last years, being recognized as a valid option to obtain NCRE energy at competitive values.

Environmental and Sustainability

We have three corporate guidelines that act as our Sustainability Pillars:

- *Socio-Environmental Policy*. It is essential for us to develop and operate our Projects in an environmentally friendly manner, ensuring an appropriate use of natural resources with clean technologies and minimizing waste. We seek to continue the development and growth of the jurisdictions in which we operate, adhering to the current legislation and environmental requirements, and carrying out projects that have a positive impact for the communities we operate in.

- *Investment in Clean Energy Projects*. We only participate in renewable energy projects, minimizing environmental impact while contributing to the formation of an environment-friendly society.

- *Relationship with the Community*. We constantly strive to maintain and promote a respectful and accepting approach towards different cultures, values and traditions of the communities we operate in through sustainable management and by actively participating in the sustainable development and growth of these communities.

We are committed to operate in a way that supports the United Nations Sustainable Development Goals ("*SDGs*") by making renewable energy the source of power to societies and communities in order to preserve the environment while creating social and economic value for the communities in which we operate. Our key SDG contributions are connected to the core of our business as we increase the share of green energy in the global energy mix (SDG 7), while mitigating climate change (SDG13). Additionally, our investments in green energy are also a source of sustainable economic growth (SDG 8).

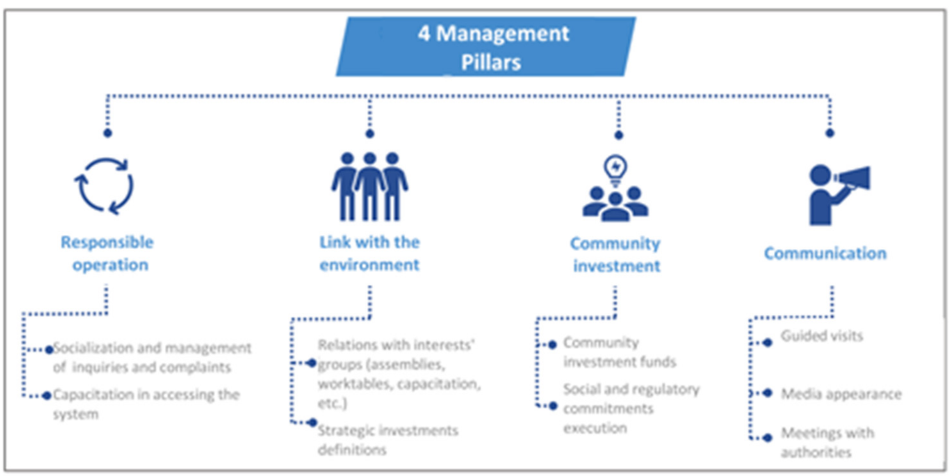
Sustainability guides all of our actions, with a strong commitment to our communities' social and environmental development:

- We conduct all of our operations in harmony with the ecosystem in which we work in, always looking after people's best interests. Our operations count with established high-standard occupational health and safety protocols and policies that must be followed by employees or contractors operating within the Projects. These are certified under the ISO 45001:2018 standard and reinforced through a prevention of occupational hazard insurance against work accidents and occupational diseases through an agreement in force with Mutual de Seguridad, a major Chilean occupational health and safety institution.

- We work in conjunction with our neighbors with the purpose of being a constant contributor to the sustainable development and growth of the communities and the environment we operate in. To this end, our management policies are certified under the ISO9001:2015 standard and our environmental management systems are certified under the ISO 14001:2015 standard.

Corporate and Social Responsibility

We are strongly committed to the responsible development of our environment, including community care and support. We aim to reducing our impact to the minimum and maintaining close and confidence-based relations to the neighboring settlements and communities. Our social management policy is based in 4 pillars:



Thanks to this, we have established a very good relationship with the communities, environmental institutions and the public opinion. In 2020, we were awarded first place for "good practices" in an annual contest held by the Chilean Generators guild (*Generadoras de Chile*), due to our management of relationships with communities. Our management policies are certified under the ISO9001:2015 standards.

Employees

As of the date of this offering memorandum, none of ILAP, San Juan nor Norvind have employees, and the operation of the energy generating plants is handled by third party contractors. Likewise, labor and bookkeeping aspects are covered under a management agreement with LAP Chile, pursuant to which San Juan and Norvind pay LAP Chile a monthly fee. See "*Related Party Transactions—Management Services Agreement.*"

Safety

Our Projects count with established high-standard occupational health and safety protocols and policies that must be followed by employees or contractors operating within the facilities. These are certified under ISO 45001:2018 standards and monitored by our Integrated Management System.

As for prevention of occupational hazards, we have an adhesion agreement in force with Mutual de Seguridad, a major Chilean occupational health and safety institution, at LAP Chile level, through which we receive technical support in prevention measures. The agreement also includes insurance against work accidents and occupational diseases.

Technology

We use a Fracttal system for the control and monitoring of our Projects. Nispera, a leading company in the Chilean market, performs predictive analyses in a regular basis to anticipate system failures based upon information obtained from our SCADA. Nispera also prepares our wind forecasts required by the National Electrical Coordinator. In addition, Saroens, another leading company in the Chilean market, performs frequent analyses of vibration levels in our turbines in order to improve our future maintenance plans. These systems, using state-of-the-art technology, allow us to predict our generation availability with better accuracy.

Measures Taken During COVID-19 Pandemic

Since the first quarter of 2020, we have taken steps to prevent the spread of the virus following the guidelines and recommendations from health authorities, including social distancing protocols and remote working, which has allowed us to maintain normal operations and protect the health and safety of operators and administrative personnel.

Legal Proceedings

As of the date of this offering memorandum, we are not involved in any claims that, either individually or on a combined basis, will have a material adverse effect on our financial position.

There are two tax legal proceedings in course, regarding Norvind's carryforward losses:

<u>Resolution No. 195</u>

On April 30, 2015, the SII formally requested Norvind to provide the relevant supporting documentation regarding tax losses declared in its annual income tax declaration (Form 22) corresponding to the fiscal year 2011. After reviewing the documentation presented by Norvind, the SII issued Resolution No. 195 ruling that the documentation submitted was not sufficient to support expenses and carryforward losses declared, for a total amount of US$ 12,229 thousand. Thus, additional corporate income taxes and fines were determined such fiscal year for an amount of US$ 2,631 thousand. The carry forward loss that Norvind had recognized, and rejected by the SII, had its origin in losses accumulated during the time the Totoral Project was in its construction period, which was conducted under the control of its previous owner (ILAP acquired Norvind on 2013).

On September 21, 2015, Norvind submitted a petition for administrative revision before the SII, adding new supporting documentation and accounting records. After the rejection of the administrative petition, and having exhausted all administrative remedies available, on December 17, 2015, Norvind requested the Judicial Review of Resolution No. 195 before Tax Courts. In parallel to the judicial procedure, Norvind engaged in discussions with the SII in order to explore the possibility to submit a new request for administrative review. Such alternative was finally admitted, and on June 9, 2020, Norvind filed a new administrative petition, which the SII resolved to recognize and set Norvind's tax loss position (carryforward losses) at US$4,245 thousand; hence, no additional corporate tax nor fines are payable in connection with the fiscal year 2011. As of the date of this offering memorandum no outstanding appeals or remedies remain pending.

<u>Resolution No. 1109</u>

On April 30, 2019, the SII issued Resolution No. 1109, whereby Norvind's tax losses declared for the fiscal 2015 were reduced from US$25,411 thousand to US$3,382 thousand. Such reduction consisted in the subtraction of the losses and expenses questioned in Resolution No. 195 (which at the time was being disputed before the Tax Courts, as described above), plus other expenses generated in subsequent years, arguing that Norvind was not allowed to recognize expenses and carryforward losses determined under criteria already rejected through Resolution No. 195.

On June 13, 2019, Norvind submitted a petition for administrative review before the SII claiming that Resolution N° 1109 was based on illegal grounds on the effects of a resolution -Resolution No. 195- that was the subject of a then pending court review. Such appeal was rejected, and on October 24, 2021, Norvind filed a claim for revision before the Tax Courts.

In parallel to the judicial proceeding, Norvind engaged in discussions with the SII in order to explore the possibility to submit a new request for administrative review. Such alternative was admitted and on April 30, 2019, Norvind filed a new administrative petition, which the SII resolved recognizing and setting Norvind's tax loss position (carryforward losses) for US$14,420 thousand per Tax Year 2016. As a consequence, the judicial procedure before the Tax Courts was terminated.

As a result of the administrative reviews of Resolutions No. 195 and No.1109, all pending procedures regarding Norvind's tax results have been terminated and it is unlikely that the SII will perform a new audit regarding tax results already recognized as per the proceedings described above.

INDUSTRY OVERVIEW

Business Segments

The Chilean electricity system is divided into three main networks: the National Electric System (*Sistema Eléctrico Nacional or* "*SEN*") and two smaller isolated networks, Aysén and Magallanes. The SEN was created in November 2017 through the integration of SIC and the SING, and it extends from the city of Arica in the north of Chile to the island of Chiloé in the south of Chile, and comprised 35,919 kilometers of transmission lines as of October 31, 2020. The National Electricity Coordinator, a centralized dispatch center, coordinates the SEN's operations. The SEN operates at a national level with just a minor international interconnection with Argentina serving some exceptional export surpluses.

In terms of energy consumption, end consumers are classified according to their demand as Regulated Customers (consumers with a connected capacity equal to or less than 5,000 kW (5 MW)); and free or unregulated customers (consumers whose connected capacity exceeds 5,000 kW (5 MW) "*Unregulated Customers*"). Customers with a connected capacity between 500 kW (0.5 MW) and 5,000 kW (5 MW) may choose to be treated as Regulated Customers or Unregulated Customers and be subject to the applicable pricing regime. However, in such case, they must remain in the selected category for at least four years. In 2019, Regulated Customers represented 41% of the electricity sold in the SEN, and Unregulated Customers represented 59%. While Unregulated Customers freely and directly negotiate the conditions for electricity supply with generation companies, Regulated Customers buy their electricity directly from DisCos at a regulated tariff set by the Ministry of Energy based on a tariff fixation procedure carried by the CNE pursuant to the rules contained in the Electricity Law and its regulations. An explanation on the tariff fixation process and the manner in which distribution companies secure energy for Regulated Customers is provided in "*Legal and Regulatory Framework—Tariff Stabilization Framework—PNLPS, PNPs and Tariff Decrees*."

The electricity sector consists of three main business segments: generation, transmission, and distribution. These segments must operate in an interconnected and coordinated manner to supply electricity to Regulated Consumers at minimum cost and within the standards of quality and security required by the industry's rules and regulations.

Generation Segment

As of October 2020, Chile's installed generating capacity was approximately 25,997 MW. Chile's generation segment is primarily composed of a mix of hydroelectric and thermal energy, although there has been a strong influx of renewables in recent years. Chile's northern and dry regions rely primarily on thermal (coal, gas and diesel), solar and wind power, whereas Chile's central and southern regions have a strong presence of hydroelectric resources in addition to thermal, solar and wind. The table below sets out the breakdown of Chile's aggregate installed capacity by technology type as of April 2021.

Technology Type	MW	% of total
Hydroelectric.........	6,944	26.8%
Thermal	12,693	49.0%
Wind......................	2,392	9.2%
Solar	3,409	13.2%
Biomass	413	1.6%
Geothermal............	40	0.2%
Total	**25,890**	**100.0%**

Since its privatization in the 1980's, the generation segment has operated competitively, and generation companies are not required to obtain sector-specific concessions from Governmental Authorities to sell electricity in the market. The only exception to this is that hydroelectric generating companies are entitled to and usually do request electric concessions permitting them to obtain easements over certain areas of land. Despite the general requirement to obtain concessions, the generation segment was a highly concentrated market until very recently. Historically, Enel Generación, Colbún, AES Gener and Engie, which had 20.0%, 11.9%, 5.3% and 6.2%, respectively, of the total installed capacity as of October 2020, were the key participants in the Chilean electricity generation market. New players such as Acciona, Mainstream and Aela, Andes Mining and Energy, Arauco Generación, Atlas, Cerro Dominador, EDF, Ibereólica, Pacific Hydro, Statkraft, and many others, have entered the market as a result of several public policies fostering competition and the development of non-conventional renewable energy projects. Some of the most important policies include:

- The NCRE Law, which requires that generation companies produce a certain amount of energy from NCRE units. This amount progressively increases until reaching 20% of the total amount of generated energy in Chile by 2025. The NCRE Law created an NCRE credits market and a penalty applicable to generation companies that do not meet the minimum NCRE generation amount or do not purchase sufficient NCRE credits;

- Law 20,805 (and subsequent regulation) improved the rules applicable to tender processes carried out by DisCos. This piece of legislation required DisCos to secure electricity supply for their Regulated Customers at least five years before the supply start date. This allowed new companies to participate in tenders and submit bids backed by greenfield power projects; and

- The Government and the largest companies having interests in coal-fired generation (Enel Generación, AES Gener, Engie and Colbún) reached a voluntary agreement in 2019 (as further developed in 2020) to prevent the construction of new coal-fired power plants and to work on a progressive decommissioning schedule to dismantle those facilities by 2040. This agreement has further encouraged the development of NCRE projects to replace the coal-fired power plants being decommissioned.

The generation segment is coordinated by the National Electrical Coordinator, which manages the dispatch of available generation facilities to ensure that demand is being satisfied by the lowest cost producer available. If a generation company produces more electricity than it has contracted to sell, it can sell excess electricity in the spot market at a price equal to the (instantaneous) hourly marginal cost of electricity to the system. Conversely, if a generation company produces less electricity than it has contracted to sell, it can purchase replacement electricity in the spot market. The instantaneous marginal cost is the cost which the system incurs to supply an additional unit of energy to satisfy demand.

In addition, generation companies may sell energy to Unregulated Customers and to other generation companies through contracts at freely-negotiated prices, and they may sell energy to DisCos for supply to Regulated Customers. Sales to DisCos are made under PPAs awarded through public tender processes carried out by the DisCos under the supervision of the CNE. For a detailed description of these tender processes, see *"—Distribution Segment—Public Tenders.*"

Transmission Segment

Transmission companies own and operate lines and substations extending from generation companies' production points to the centers of consumption or distribution. Due to economies of scale and geographic particularities, the transmission segment is a natural monopoly subject to special industry regulations. Tariffs are highly regulated, and access is open and guaranteed under non-discriminatory conditions.

The New Transmission Law established a new regulatory framework for all electricity transmission systems in Chile, redefining the system into the following main segments:

- The National Transmission System is the high voltage backbone of the whole system, where electricity flows dynamically according to supply and demand. The National Transmission System is subject to an open access regime where transmission companies are required to provide service to generation companies, other transmission companies and end consumers that seek to connect, subject to certain standard and objective conditions. If transmission capacity is not sufficient, potential users, comprised of generation companies, transmission companies and end consumers, may request that the National Electrical Coordinator expand certain facilities, and the National Electrical Coordinator may include those expansions in the expansion plan of the SEN, subject to technical and economic conditions.

- The Local System is a single system, with facilities all along the country, that allows the transportation of electricity from the National Transmission System to distribution concession areas. These networks connect the National Transmission System to local distribution facilities. The Local System is subject to the same open access regime as the National Transmission System.

- The Dedicated System is composed of dedicated facilities through which generation companies deliver electricity to Unregulated Customers. The Dedicated System is also subject to an open access regime, provided technical capacity is available. Unlike the owners and users of the National and Zonal Systems, owners and users of Dedicated System facilities are not required to expand their facilities upon request of third parties seeking an interconnection.

Annual tariffs payable for the use of each existing section of the National and Local Systems are set by the Ministry of Energy every four years based on a valuation study conducted by an independent consultant pursuant to a bidding process that is subject the review of the Experts' Panel. Annual tariffs are intended to cover (i) the annual value of investment plus (ii) the costs of maintenance, operation and administration (together with the AVI, the "*VATT*"), and they are passed through by the DisCos to Regulated Customers.

Under the New Transmission Law, generation and distribution companies pay national and local transmission companies 100% of the VATT associated to the applicable transmission company's facilities, which is passed through to end consumers (whether Regulated or Unregulated Customers) pursuant to the tariffs calculated by the CNE. Owners of dedicated facilities will also be entitled to receive the portion of the VATT associated with the relevant facility (i.e., generally the one associated to the portion of the capacity actually contracted) as set forth in the corresponding toll agreement. Unlike owners of National and Zonal facilities, the owner of a dedicated facility must collect tariffs directly from users.

Distribution Segment

The distribution segment uses transmission infrastructure with a voltage lower than 23 kV to supply electricity to end consumers. Electricity distribution is considered a natural monopoly; therefore, companies operate under a public utility concession regime, with service obligations to supply Regulated Customers at regulated tariffs.

The DisCos Short Law introduced the obligation that DisCos be incorporated in Chile as stock corporations (*sociedad anónima*), subject to mandatory reporting and disclosure obligations. It also required that DisCos have the distribution of energy, together with infrastructure-related business activity, as their sole business purpose, although they are allowed to perform ancillary business activities through special purpose vehicles having independent accounting records.

Distribution Concessions

Granting of Concessions

To provide energy distribution services to Regulated Customers, a company must obtain an electric distribution concession from the Minister of Energy. Applications for distribution concessions are subject to a non-discretionary procedure established in the Electricity Law. If the procedure is followed correctly, the Minister of Energy will issue a decree granting to the applicant a distribution concession for a specific geographical area. If a DisCo that has already been granted an ongoing concession requires an additional concession to service an expanded area, a new concession application can be filed for that specific area following the same non-discretionary procedure. The holder of any electric concession is required to have the concession decree recorded into a public deed once such decree is published in the Official Gazette.

Although the Minister of Energy may grant new concessions over an area already covered by an existing concession or over an area that overlaps with an existing concession, this has only taken place where new residential or urban developments are being built and new distribution facilities are required to service the new area. As a result, competition among distribution companies is limited to new service areas and not to areas already being served by an ongoing distribution concession. Therefore, DisCos operate as effective monopolies in the areas they serve pursuant to distribution concessions.

Term

Distribution concessions are granted for a perpetual term and give a DisCo the right to use public lands located within the concession area to build and maintain distribution lines and ancillary facilities. The DisCo is not required to make any payments or post any bonds or other collateral to obtain or maintain a valid distribution concession once it has been granted.

Obligations of DisCos with Distribution Concessions

DisCos with distribution concessions have the obligation to supply electricity to all customers who request service within their concession area on a non-discriminatory basis, and they are required to have contracted a sufficient amount of electricity to supply their Regulated Customers. DisCos also have the obligation to properly maintain distribution networks. Natural phenomena and disasters, such as inclement weather, floods, tremors earthquakes and tsunamis, have challenged DisCos' ability to provide uninterrupted distribution service to end consumers. For instance, in 2018 the Chilean Supreme Court confirmed a fine of US$2.6 million against CGE for a failure to provide service to 295 Regulated Customers for more than 20 hours as a result of inclement weather conditions. Similarly, in 2016 the Chilean Supreme Court confirmed a fine of US$2 million against Enel Distribución Chile S.A. for a failure to provide service to 9,648 Regulated Customers for more than 20 hours as a result of inclement weather conditions.

Transfer and Assignment

The holder of a distribution concession is not allowed to transfer (either in the form of an assignment, purchase or a merger) or lease the concession to third parties, unless consent from the Minister of Energy is previously granted. The Minister of Energy must refuse to grant consent if the transfer of the concession creates losses of efficiency by increasing the applicable service price within the area covered by the concession, the other areas serviced by the assignor or by the assignee of the concessions (if any). The Ministry of Energy is required to take into account (but is not bound by) the reports issued by CNE and the SEC on this point. In practice, transfers of concessions have been limited to transfers within a DisCo's corporate group. The Electricity Law does not prevent a change of control in the ownership interest of a DisCo.

Termination

Existing distribution concessions can only be revoked by the President of Chile for:

- Poor quality of service, unless the concession holder remedies the breach within the term specified by the SEC or the breach is not attributable to the concession holder or is the result of an event of force majeure. As of the date of this offering memorandum, there are no cases in which the President has revoked a distribution concession in operation.

- Failure to obtain the Minister of Energy's consent prior to assigning the concession to a third party.

No compensation is payable to the DisCo in the event a concession is revoked based on legal grounds. The revocation of a concession does not necessarily entail the imposition of fines or the like on the DisCo. However, to the extent infringements take place, the SEC is entitled to impose fines of up to US$7,500,000.

Compensation

The DisCos are entitled to the "aggregated distribution value" ("*VAD*") which seeks to remunerate the DisCos for the cost of investment, operation, maintenance and administration of their distribution infrastructure.

The VAD is based on a price-cap scheme which aims to enhance the efficiency of the DisCos by comparing the DisCos to a fictional model company created for purposes of tariff setting. The VAD considers the cost of infrastructure and the costs of operating, maintaining and administrating that infrastructure at the minimum price, fulfilling all applicable quality and safety standards of a company within a cluster of geographical areas (known as typical distribution areas) with similar characteristics in terms geography, population, density, climate conditions and type of demand, among other criteria ("*TDA*").

The CNE classifies all DisCos according to their TDA and subsequently selects one company from each TDA to estimate its cost as compared to the efficient model company. DisCos also carry out their own models to determine the costs compare to those of an efficient model company. Cost estimates include fixed expenses, average energy and capacity losses, standard investment costs, and operation and maintenance costs. Annual investment costs are calculated considering the replacement cost of installations, useful life thereof, and a rate of return that the CNE calculates every four years. Then, the real return on investment for a DisCo depends on its actual performance relative to the standards chosen by the CNE for the efficient model company.

As of the enactment of the DisCos Short Law, the VAD is fixed every four years by decree of the Ministry of Energy based on a technical report prepared by an independent consultant and reviewed by the CNE and the Experts' Panel. In each TDA, the VAD encloses the investments and operational costs, electricity losses, maintenance and management costs, billing, and customer service considering the above-mentioned efficient model company structure.

Preliminary tariffs, with the resulting VAD, are tested to ensure that they provide an industry aggregate rate of return to the DisCos between 6% and 8%. The DisCos Short Law establishes that the after-tax rate of return for each DisCo must be between three percentage points below and two percentage points above the rate of return calculated by the CNE.

The VAD that DisCos are entitled to is different and separate from the PNP they collect from Regulated Customers to pay electricity supplied from awarded generation companies. Consequently, the Regulated Customers' tariff structure is composed of the VAD (actual compensation of the distribution company), the PNP and the charges for the use of the transmission system and the public service charge (which are collected and then transferred to the relevant power and transmission companies). Although Regulated Customers are entitled to select among (or required to have) different types of tariffs from their DisCo based on the voltage level required and other specific conditions, these tariffs only relate to the VAD portion of the total charge and do not affect the PNP portion collected to pay awarded generation companies.

The VAD which is to apply to the DisCos for the period of 2016 to 2020 was issued by the Ministry of Energy in July 2018. That VAD will be in effect until the VAD for the period of 2020 to 2024 has been issued. The Ministry of Energy's process to determine this new VAD began in January 2020 and, as of the date of this offering memorandum, is still ongoing.

Market Dynamics

Installed Capacity

The Chilean electricity system is divided into three main networks: the National Electric System (Sistema Eléctrico Nacional or SEN) and two smaller isolated networks, Aysén and Magallanes. The SEN was created in November 2017 through the integration of SIC and the SING, and it contains approximately 99% of the country's installed capacity. According to the National Electrical Coordinator, total installed capacity for electricity generation in the SEN Chile stands at 25,997 MW as of October 2020.

Chile has added the vast majority of its non-hydro renewable capacity in the last seven years. The renewables build-up was supported by the national government mandate enacted in 2013 (amendment of Law No. 20.527) and its requirement that utilities with more than 200MW of operational capacity meet 20% of their contractual obligations with renewable sources by 2025.

In addition to the national mandate, Chile has bolstered the clean energy expansion by enacting specific policies to promote renewables. Key developments to bolster renewables growth include:

1. *Tenders to secure clean power-delivery contracts:* Chile has implemented reverse auctions to procure power from various sources since 2006. In 2014 the government created an auction structure specifically tailored to suit wind and solar developers' requirements. Generators now compete in auctions to supply power during specific time-periods of the day increasing the competitiveness of intermittent sources such as wind and solar by allowing their developers to bid most aggressively for the blocks when they can best serve the market. In these actions, renewables compete directly with fossil sources of generation and as wind and solar costs declined, renewables have become increasingly cost-competitive.

2. *Net billing to promote distributed generation:* In 2014, Chile began allowing local, distributed power-generators such as rooftop PV systems to "sell" excess power back to their utility at the retail rate via compensating discounts on electricity bills. The program is similar to "net metering" schemes in some U.S. states and elsewhere around the world. Distributed solar however still remains a small component of renewables and the overall grid.

3. *Coal moratorium.* In 2019, Chile announced a plan to retire all of country's coal-fired capacity by 2040 (5 GW), and included a schedule to retire the first 1GW by 2024. Chile became the first South American nation declare a coal moratorium. All coal power plant owners, including AES Gener, Colbún, Enel and Engie, have committed not to invest in new projects.

Marginal Cost

The marginal cost of electricity generation corresponds to the cost incurred to supply an additional unit at a given level of production and is a key driver of electricity prices. Over the past 10 years, the marginal cost in Chile has generally trended downward, reflecting the introduction of renewables and other more cost-efficient technologies, despite increases in overall generation and demand.

Electricity Demand

Overall Consumption

Chilean electricity consumption per capita is at a high level compared to other countries in the region. According to the International Energy Agency ("*IEA*"), Chile's per capita electricity consumption was 4.2 MWh for 2018. This is above Argentina, Brazil, Mexico, Peru and Colombia.

Chile's final electricity consumption in 2018 was concentrated in the industrial and residential sectors, which represented 60% and 18% of final electricity consumption, respectively. The charts below illustrate final electricity consumption by economic sector in 2018 and the evolution of this breakdown since 1990:

Public Tenders

Before 2015, each DisCo or small groups of DisCos purchased electricity through public, transparent and competitive tender processes. Since the enactment of Law N° 20,805/2015 the process is generally carried out by all DisCos acting together with the support and oversight of the CNE. This has enabled smaller DisCos with less negotiation leverage as well as their Regulated Customers to benefit from more favorable pricing and standardized supply terms and conditions.

Because DisCos are required to have access to enough electricity to serve their Regulated Customers, the amount of electricity tendered for is based on each DisCos' projected requirements. DisCos are required to notify the CNE on a semi-annual basis of their projected electricity requirements to enable the CNE to undertake a new tender for a sufficient amount of electricity. The CNE is required to ensure that DisCos always have enough electricity to serve Regulated Customers, it must carry out tenders five years in advance of the supply start date and it may not award PPAs for a term of more than 20 years.

If the CNE decides that a new tender is required, the tender process must be conducted at least five years in advance of the expected supply start date for the contracts to be awarded. The CNE prepares the tender terms and conditions, which must include at least (i) the amount of electricity being tendered, (ii) the identification of energy and hourly blocks demanded by each DisCo (based on projections previously provided to the CNE), (iii) the supply period, which cannot exceed 20 years, (iv) the supply points, (v) the award criteria (which must ensure the most economic bids are being awarded) and (vi) a template of the relevant PPA, which is not subject to amendments or negotiation between the DisCos and the bidders during the tender or after the award. Once the process is completed, awarded bidders must execute the relevant PPA with each of the DisCos that participated in the tender. Any amendment to the PPA or its assignment must be approved by the CNE.

Although Regulated Customers' demand has historically remained steady, the PPAs are not subject to take or pay provisions and, therefore, DisCos are required to pay for the electricity actually demanded. To the extent a DisCo has more than one PPA in place, the electricity effectively demanded will be assigned to each of those PPAs on a pro rata basis based on the proportion that the contracted volume under each PPA represents of the aggregate volume contracted by that DisCo.

DisCos are required to pay each generation companies with whom it has entered into a PPA the price awarded to it in the tender, adjusted by the indexation formulae included in the winning bid and ultimately in the applicable PPA.

Because these contract prices are set in U.S. Dollars and the DisCos collect tariffs from Regulated Customers is in Pesos, prices (together with the applicable indexation offered in the tender) must be converted into Pesos. A PPA price converted to Pesos is known as a Long Term Nodal Price (*Precio de Nudo de Largo Plazo*). The PNLP of each PPA (including its adjustment) is calculated semiannually by the CNE based on a preliminary and definitive technical report which is then included in Tariff Decrees and issued semi-annually by the Ministry of Energy on May 15 and November 15 of each year.

The PNLP for each PPA included in the Tariff Decree issued on May 15 applies from July 1 to December 31 of that same year while the PNLP included in the Tariff Decree issued on November 15 applies from January 1 to June 30 of the following year. To convert the U.S. Dollars into Pesos for these purposes, the CNE uses the monthly average Observed Exchange Rate for each of the six months prior to the month in which the relevant preliminary technical report must be issued (i.e., six months prior to April or October, as applicable).

The Tariff Decree also establishes the PNP, the price of electricity that DisCos must charge to Regulated Customers for the supply of electricity. The PNP is calculated for each DisCo as the weighted average of the PNLPs (as such PNLPs are calculated in the same Tariff Decree) for each of the PPAs executed by that DisCo plus certain other systemic costs. Therefore, payments collected from Regulated Customers simply seek to cover the DisCos' cost of electricity acquired to supply Regulated Customers and do not represent compensation for the DisCos. For additional detail on the DisCos' actual compensation, see "—*Compensation*."

If supply or demand deviate from the CNE's expectations, the CNE may carry out short-term tenders. Unlike regular tenders, these tenders can be subject to extraordinary terms and conditions specifically defined by the CNE. In addition, should a DisCo face a deficit in demand and a short-term tender not occur, DisCos that have a surplus of electricity contracted with awarded generation companies may transfer their surplus to DisCos suffering the deficit on the terms and conditions as agreed in the PPA originating the surplus. In addition, if the insolvency of a generation company triggers an early termination of a PPA, the remaining generation companies must continue to supply the DisCos' demand on a pro rata basis based on the proportion that each generation company's commitments with end customers represent over the total energy demanded by the DisCo. Participating generation companies receive the purchase price that the insolvent generation company was entitled to receive under the applicable PPA. The regulation providing for this mechanism was an ad-hoc regulation enacted during the only notable bankruptcy of a power company (i.e., Campanario Generación in year 2011) that had contracts with DisCos in place. Although no further regulation has been issued thereafter, it is expected that substantially the same mechanism will apply in the event of future bankruptcies.

LEGAL AND REGULATORY FRAMEWORK

Overview

Chile's electricity sector has a regulatory framework that has been in effect and has evolved significantly over more than three decades. This has enabled the development of an industry with a high level of participation of private capital to drive the industry's development. See "*Industry Overview*." The electricity sector and its private participants are subject to various regulations and the supervision of various technical bodies. The material laws and regulations covering the Chilean electricity sector are contained in the Electricity Law, the Transmission Law and the Environmental Law.

Chile has a mixed electricity generation portfolio and has had a strong increase in renewable energy in recent years. As of October 2020, the country's installed generating capacity was approximately 25,997 MW (6,793 MW of hydroelectric, 12,916 MW of thermal, 2,527 MW of wind; 3,266 MW of solar, 451 MW of biomass and 45 MW of geothermal).

The electricity sector is governed mainly by the Electricity Law, as amended. The Electricity Law governs the generation, transmission and distribution of electricity in Chile and provides incentives to maximize efficiency. It provides a simplified regulatory scheme and tariff-setting process that limits the discretion of the government in the tariff-setting process. The Electricity Law has been amended from time to time, including by:

- Short Law I, which established, among others, a new regulation applicable to the transmission system;
- Short Law II, which established, among others, a public, open, non-discriminatory and transparent tender process to secure electricity supply of DisCos' Regulated Customers;
- Law No. 20,220 of 2007, as amended by the Bankruptcy Law, which established, among others, special rules for the bankruptcy of generation, transmission or DisCos;
- NCRE Law, which, among others, encouraged the development of non-conventional renewable energy units by requiring that certain amount of electric power withdrawn by power companies be generated by such type of power units (20% by 2025);
- Law No. 20,571, enacted in 2012, among others, regulating the net metering (net billing) and payment to residential and industrial small generators (up to 100 kW) and promoting the participation of NCREs in the national energy matrix, allowing NCRE producers to inject their surplus to the grid under a net billing scheme;
- Chilean Law No. 20,805 of 2015, which improved the regulation applicable to tender processes carried out by DisCos and overseen by the CNE to secure the electricity supply for their Regulated Customers;
- Transmission Law, which, among others, modified the regulatory framework applicable to the transmission system and created the National Electrical Coordinator;
- Tariff Stabilization Law, which, among others, stablished a stabilization mechanism for energy and power prices that Regulated Customers pay to DisCos by bringing forward the projected reduction in supply prices; and
- DisCos Short Law, which, among others, established a new methodology to set the distribution tariffs of the DisCos.

As of the date of this offering memorandum, the Chilean Congress was discussing a bill that would amend the

Electricity Law to incorporate a new entity into the electricity distribution system in Chile to promote competition. This entity would be a private enterprise which, like generation companies and DisCos, would be subject to the oversight of the CNE and the National Electrical Coordinator. As currently envisioned, a trader would be able to purchase blocks of energy from generation companies and sell sub-blocks of energy to Regulated Customers at prices comparatively lower than those offered by DisCos. Currently, only generation companies are allowed to sell electricity to DisCos and end consumers. Based on the current status of the legislative discussion, this new entity and its activities is not expected to reduce the amount of electricity that awarded generation companies currently supply to DisCos. Current status of legislative discussion suggests that the energy blocks such trader would be permitted to trade will be either related to (i) incremental demand of Regulated Customers not being supplied by awarded generation companies or (ii) energy blocks being released by awarded generation companies as a result of the termination of their PPAs.

Relevant Authorities

The regulatory agencies that have primary responsibility for the implementation and enforcement of the Electricity Law are the Ministry of Energy, the CNE, the Superintendency of Electricity, the National Electrical Coordinator, and the Experts Panel, as defined and described below.

The Ministry of Energy

The Ministry of Energy is the highest governmental authority in the energy sector, responsible for the plans, policies and regulations (usually in the form of decrees) required for the development of the electric power industry and for promoting energy efficiency, reliability and safety. The Ministry of Energy awards distribution concessions, permitting DisCos to provide service to Regulated Customers located within the geographical boundaries of the concession.

The Minister of Energy is appointed by the President of Chile as the head of the Ministry of Energy and is entitled to issue and execute most official documents, including Tariff Decrees, and decrees that determine the tariffs that DisCos are entitled to, decrees that provide for the expansion of the transmission systems and decrees that grant distribution and transmission concessions. In the Minister of Energy's absence, the Undersecretary of Energy, who is also appointed by the President, acts in place of the Minister of Energy and executes all official documents in case of temporary absence or disability.

The National Energy Commission (CNE)

Administratively dependent on the Ministry of Energy, the CNE is the technical agency in charge of creating and coordinating plans, policies and regulations for operating and developing the industry and advising the government in all energy-related matters. Among other things, the CNE drafts the administrative regulations that the Ministry of Energy enacts and/or the technical reports used to issue administrative regulations, including, as described below, the CNE publishes the preliminary and definitive technical reports based on which the Ministry of Energy issues Tariff Decrees. The CNE also organizes and oversees public bids for the transmission and distribution sectors (including, as described below, public tenders carried out by DisCos to secure PPAs to supply their Regulated Customers).

The Executive Secretary of the Ministry of Energy is the head of the CNE and is appointed by the President after a public and competitive nomination process.

Every four years the CNE leads the tariff-setting processes for the transmission system through a transmission facilities valuation study ("*TFVS*"), and the distribution companies aggregated value ("*DCAV*") tariff-setting process. The CNE set the grid code ("*NTSyCS*") and approves different codes or norms for the functioning of the National Electrical Coordinator and the SEN.

The Superintendency of Electricity

The SEC supervises compliance with legal, administrative and regulatory provisions, initiating investigations, imposing sanctions for breach of relevant regulation and interpreting legal and administrative provisions applicable to the electricity sector. It also gives general instructions to the companies and entities subject to its supervision and solves certain minor conflicts. The SEC oversees the applications for concessions for hydroelectric plants, electric power switchyards, transportation lines and for electricity distribution, although it is the Minister of Energy who then grants the concession.

The SEC's sanctions for breach of applicable regulation range from imposing fines ranging from approximately US$750 to US$7,500,000 to revoking provisional concessions and authorizations and instructing the closure of facilities. These fines may be appealed in a court of law. To determine the applicable sanction, the SEC must take into consideration the magnitude of the damage caused, the number of end consumers affected, the economic benefit obtained by the offender, intentionality and degree of participation of the offender, including its past behavior, financial capacity and whether the infringement is "very serious" (causing generalized failure of the system), "serious" (posing a danger to the regularity, continuity, quality and safety of the service), or "a minor infringement" (an act or omission that infringes upon any mandatory provision of applicable law or regulation and is not considered very serious or serious). In practice, sanctions imposed are limited to fines and written admonitions. In fact, as of the date of this offering memorandum, the SEC had never instructed the closure of generation, transmission or distribution facilities and the President had never revoked a distribution concession in operation. The Superintendent is the head of the Superintendency of Electricity and is appointed by the President after completing a public and competitive nomination.

The National Electrical Coordinator

The Transmission Law centralized the dispatch and coordination of the SEN in the National Electrical Coordinator, an independent system operator which replaced the CDECs. Unlike the CDECs, the National Electrical Coordinator is not only independent from market players and government administration, it is also a non-for-profit entity aimed at ensuring the safety, continuity and reliability of the service provided by the SEN.

The National Electrical Coordinator programs the dispatch of electricity generation units and oversees the operation of transmission facilities, seeks to preserve the safety and continuity of the electricity system, secures the most affordable operation for all facilities in the electricity system as a whole, and guarantees open access to all transmission systems. One of the main purposes of the National Electrical Coordinator in operating the system is ensuring that only the most efficiently produced electricity is dispatched to customers. The National Electrical Coordinator dispatches plants using different generation technologies to satisfy the demand and it relies on a schedule based on the variable cost of generation, and dispatches plants by starting with the lowest-cost plants, so that electricity is supplied at the lowest-available cost. Marginal cost of production at solar plants, wind farms and run-of-the-river hydroelectric plants are generally the lowest in the SEN. Therefore, under normal conditions, solar, wind and hydroelectric capacity are generally dispatched first. Power generation companies balance their contractual obligations with their dispatches by buying or selling electricity at the spot market price, which is set on an hourly basis by the National Electrical Coordinator, based on the marginal cost of production of the next most expensive kWh to be dispatched on merit order. The dispatch schedule always considers transmission and security constraints, so that the prices reflect the cost of dispatching the system to lessen any constraints.

The National Electrical Coordinator also monitors competition in the power sector, supervising the chain of payments and balancing transmission payments (both payment revenue and flat charges, which must be paid to the owners of the transmission facilities) and, together with the CNE, has a central role in planning the expansion of transmission, enabling the connection of new generation and transmission units to the electric system. The National Electrical Coordinator does not have the power to impose sanctions, but it may instruct that an Unregulated Customer be disconnected from the electricity system if it does not have a contract with a generation company.

The Experts Panel

The Experts Panel is a tribunal exclusively created for the energy sector and comprised of independent professional experts in their field with recognized market experience. Its duty is to resolve certain technical and sector-specific disputes, between the National Electrical Coordinator or certain authorities and the companies subject to their coordination and control or between electric companies themselves. The scope of the Experts Panel's jurisdiction is limited to disputes arising from certain matters expressly specified in the Electricity Law. The Experts Panel has very limited authority to resolve disputes that arise in the context of the Tariff Stabilization Mechanism.

Tariff Stabilization Framework

Overview

As a result of the social unrest that began in Chile in October 2019, the Tariff Stabilization Law was enacted on October 30, 2019, and published in the Official Gazette on November 2, 2019, to temporarily stabilize electricity prices for Regulated Customers. This law outlined the temporary Tariff Stabilization Mechanism intended to rescind a recent increase in electricity tariffs payable by Regulated Customers and contained in Tariff Decree No. 7T of 2019, while taking advantage of future reductions in energy prices payable by DisCos under PPAs that had already been awarded at lower prices, to ensure that generation companies would be made whole over time. The concepts introduced in the Tariff Stabilization Law were implemented through the Tariff Stabilization Resolution. The Tariff Stabilization Mechanism introduced amendments to the manner in which the PNP is calculated as detailed in "*—PEC: Stabilized PNP*."

PNLPs, PNPs and Tariff Decrees

Payments in connection with the supply and distribution of electricity to Regulated Customers in Chile are based on two main concepts: PNLPs and PNPs. A PNLP represents the price payable by a DisCo to a generation company under a PPA awarded pursuant to a public tender, indexed, as applicable, to inflation and/or fuel costs and converted from U.S. Dollars to Pesos as agreed in each PPA. PNLPs are, therefore, PPA-specific but not necessarily DisCo-specific, since more than one DisCo can have the same price conditions under PPAs awarded in the same tender. A PNP, is the price that Regulated Customers pay to a specific DisCo for the supply of electricity during the applicable Tariff Period, and which is a weighted average of the PNLPs payable by such DisCo, taking into account certain other factors. In any specified Tariff Period, the Tariff Decree will set out a PNP for each DisCo, which applies to all Regulated Customers of that DisCo alike. PNLPs and PNPs are set out in Tariff Decrees issued by the Ministry of Energy, and they typically apply for a Tariff Period of six months or, if there is a delay in the issuance of the next Tariff Decree, until the next Tariff Decree becomes effective. In addition, each Tariff Decree will also weigh in the *precios de nudo de corto plazo* applicable to a marginal proportion of contracts that were executed prior to 2005 and that continue in effect.

The Ministry of Energy is required to issue Tariff Decrees by or on May 15 and November 15 of each year (or the following Chilean business day, if applicable) based on preliminary and definitive technical reports issued by the CNE. Preliminary technical reports are due within the first ten Chilean business days of April and of October of each year, and definitive technical reports are due by May 1 and November 1 of each year (or the following Chilean business day, if applicable). Preliminary technical reports and definitive technical reports are published on the CNE's website, while Tariff Decrees are published in the Official Gazette and subsequently on the CNE's website. Once issued, the Office of the Comptroller General, is required to confirm the legality (*toma de razón*) of each Tariff Decree within 15 Chilean business days, which can be extended for an additional 15 Chilean business days. The Comptroller General reviews each Tariff Decree for compliance with Chilean law and approves or rejects it on legal, rather than technical, grounds. If approved by the Comptroller General, a Tariff Decree will carry a presumption of legality and be published in the Official Gazette. In practice, the Comptroller General has taken more than those 15 or 30 Chilean business days to confirm the legality of a Tariff Decree due to, among other reasons, the complexity of the matters addressed in the Tariff Decrees or the need for the Ministry of Energy to make corrections to the Tariff Decrees.

The Tariff Decree that is to be issued on or by May 15 of each year sets out the PNLPs and PNPs applicable from July 1 to December 31 of that year, while the Tariff Decree that is to be issued on or by November 15 of each year sets the PNLPs and PNPs applicable from January 1 to June 30 of the following year. Although these deadlines are set forth in the relevant regulations, they are rarely met. Each of the CNE, the Ministry of Energy and the Comptroller General have missed deadlines in recent experience, although the Comptroller General has done so more frequently. For additional detail on remedies available against Chilean government entities failing to perform the actions required under the Tariff Stabilization Framework, see "*—Legal Challenges*." In fact, the Tariff Decree that should have applied during the first semester of 2020, was published on November 2, 2020 and the Tariff Decree that should have applied during the second semester of 2020 was published on March 20, 2021, and as of the date of this offering memorandum, the Tariff Decree that should apply during the first semester of 2021 was issued on March 2021. Likely explanations for the Comptroller General's delays are the result of a combination of a long backlog of legality confirmations at the Comptroller General's office, logistical and other difficulties caused by the COVID-19 pandemic and lack of familiarity with the recently enacted Tariff Stabilization Framework.

As a result, if a Tariff Decree is not enacted and approved within the specified deadlines, the Tariff Decree that is then in force remains in force until the delayed Tariff Decree is enacted and approved. If a Tariff Decree remains in effect beyond its intended six-month Tariff Period because of a delay, the Electricity Law requires that the PNP included in the Tariff Decree to be issued after the delayed Tariff Decree take into account any excesses or shortfalls in payments made during the period of the delay.

The Electricity Law specifically permits DisCos and generation companies to make comments and observations to preliminary reports within five Chilean business days after receipt of each report by the relevant entity, but it is silent as to whether these interested parties may similarly comment on definitive technical reports or Tariff Decrees. Nevertheless, in practice, DisCos and generation companies comment informally on definitive reports and even on Tariff Decrees, and those comments have resulted in the revocation and issuance of new definitive technical reports as well as Tariff Decrees, by application of article 62 of Law No. 19,880, which allows the authority to unilaterally amend errors in administrative acts. If administrative acts such as technical reports and Tariff Decrees contain errors or omissions which produce negative economic effects on private individuals and legal entities, affected parties may initiate general judicial actions against the CNE or the Ministry of Energy, as applicable, to have the applicable act revoked or receive compensation for any damages. As of the date of this offering memorandum, no judicial actions of this type have been filed and no judicial or administrative actions have been filed seeking to have a preliminary or definitive report or a Tariff Decree revoked. For details regarding available claims see "—*Legal Challenges*."

Before the Tariff Stabilization Law was enacted, the Ministry of Energy set out a PNP for each DisCo in each Tariff Decree, and it calculated each DisCo's PNP as (i) the weighted average of the PNLPs set out in that Tariff Decree for that DisCo's PPAs *plus* (ii) certain other systemic costs *minus* (iii) certain discounts, where applicable, pursuant to Chilean Law No. 20,928. Each DisCo would, therefore, collect its PNP from its Regulated Customers and pass the payment through to its suppliers as payment under its PPAs. The Tariff Stabilization Mechanism temporarily changed the way the PNP was calculated for the period from July 1, 2019 to December 31, 2020.

PEC: Stabilized PNP

The Tariff Stabilization Law introduced, on a temporary basis, a new concept into the electricity distribution payment system: the PEC. Under the Tariff Stabilization Law, the PNP applicable to each DisCo between July 1, 2019 and December 31, 2020, was equal to the PNP in effect for that DisCo as of June 30, 2019, as set out in Tariff Decree No. 20T of 2018, published in the Official Gazette on May 6, 2019. That PNP cannot be increased andwas not subject to indexation until January 1, 2021. The stabilized PNP contained in Tariff Decree No. 20T of 2018 is known as the Regulated Customer stabilized price (*precio estabilizado a cliente regulado* or PEC).

Beginning on January 1, 2021, and for so long as the Tariff Stabilization Mechanism is in effect, semi-annual Tariff Decrees will continue to set out PNLPs and PNPs for each DisCo; however, after the issuance of each Tariff Decree, a DisCo will not be permitted to charge its Regulated Customers a tariff higher than the Adjusted PEC. The Tariff Stabilization Mechanism will cease to apply on the earlier of (a) December 31, 2027 or (b) the date on which the PEC Receivables have been paid in full.

For as long as the Tariff Stabilization Mechanism is in effect, each DisCo will continue to pay its suppliers the PNLPs set out in each Tariff Decree; however, to ensure the PNLPs are not higher than the amount DisCos collect from Regulated Customers, the CNE is required to apply an adjustment factor to reduce the PNLPs calculated for PPAs with supply start dates prior to January 1, 2021. PNLPs relating to PPAs with supply start dates originally scheduled to start on or after January 1, 2021, will not be subject to an adjustment factor (or will be subject to an adjustment factor equal to (1) and will be calculated as described in "—*PNLPs, PNPs and Tariff Decrees.*"

PEC Receivables

If, as a result of the Tariff Stabilization Mechanism, the PEC or Adjusted PEC applicable during a Tariff Period is lower than the PNLP that would otherwise have applied during that Tariff Period by a DisCo to a generation company under a PPA were the Tariff Stabilization Mechanism not in effect, the difference between that PEC and that PNLP will constitute an unpaid balance (*saldo*) and recognized as an account receivable payable by that DisCo to that generation company under that PPA. Under the Tariff Stabilization Framework, PEC Receivables will accrue until the earlier of (i) June 30, 2023 or (ii) the date on which the total aggregate face value of all PEC Receivables reaches US$1,350 million. The CNE is required to track and inventory the accrual of PEC Receivables, and if necessary, it is required to apply an adjustment factor to the PEC or the Adjusted PEC to prevent the total amount of PEC Receivables recognized from exceeding this maximum amount.

The Tariff Stabilization Framework also recognizes as PEC Receivables certain amounts arising from mismatches in DisCos invoicing and purchases. An "invoice mismatch" is the result of the pricing difference between the PPA prices applied and adjusted pursuant to their terms and the prices included in the corresponding Tariff Decree and passed through to Regulated Customers. Because prices under PPAs between DisCos and generation companies pursuant to public tenders are deemed adjusted per their applicable indexer every time a short term nodal price decree is enacted (which is expected to be in February and August of each year) there is a period of time until the following Tariff Decree is issued during which Regulated Customers will pay a tariff under the then-current Tariff Decree that is likely not to reflect the actual cost of electricity under the PPAs.

A "purchase mismatch" is the result of the pricing difference between the point in the system where the energy supplied (or "injected") by generation companies is sold and the point in which the energy is withdrawn by generation companies to supply DisCos and their Regulated Customers. Given that there might be a difference between the marginal costs applicable in both sale supply points at the time of each injection and withdrawal, generation companies are entitled to receive such difference in the form of a "tariff harmonization adjustment" which is calculated by the CNE and added as a "tariff harmonization charge" to the PNP in the Tariff Period following the period in which the difference is generated. Every time there is a purchase mismatch or invoice mismatch that should be added to the PEC, such purchase mismatch or invoice mismatch will be recorded as a PEC Receivable in the relevant Tariff Decree.

The CNE is required to calculate and record in the preliminary and definitive technical reports issued in connection with each Tariff Decree, the amount of PEC Receivables that accrued in the preceding Tariff Period, and the Ministry of Energy is required to incorporate the PEC Receivables identified that definitive technical reports in the Tariff Decrees to which they relate by including them in the PEC Receivable Accrual Chart attached to each Tariff Decree. The Tariff Stabilization Mechanism did not modify the dates on which preliminary and definitive technical reports or Tariff Decrees are required to be issued.

Each preliminary technical report, definitive technical report and related Tariff Decree will include a table (the "*PEC Receivable Accrual Chart*") denominated in U.S. Dollars that sets out (a) the amount of any PEC Receivables accrued during the immediately preceding Tariff Period, (b) the amount of PEC Receivables included in the prior Tariff Decree, and (c) the total cumulative amount of any PEC Receivables, in each case payable by each DisCo to each generation company under each PPA.

The table below sets out a form of PEC Receivable Accrual Chart.

Identification of PPA and Parties (DisCo and GenCo)	PEC Receivables accrued for energy payments in the new accumulation period indicated in the Tariff Decree	PEC Receivables accrued for capacity payments in the new accumulation period indicated in the Tariff Decree	PEC Receivables created due to tariff harmonization in the new accumulation period indicated in the Tariff Decree	Other adjustments applicable to prior Tariff Decree	Total amount of new PEC Receivables accrued in the period covered by the Tariff Decree	Total amount of PEC Receivables included in the prior Tariff Decree	Total amount of accrued PEC Receivables
			US$				
	(A)	(B)	(C)	(D)	(E=A+B+C+D)	(F)	(E+F)

The first Tariff Decree recognizing PEC Receivables is Tariff Decree No. 6T issued on May 8, 2020, which was published in the Official Gazette on November 2, 2020, and it applied from January 1, 2020 to June 30, 2020. This Tariff Decree recognized US$350,064,269 in PEC Receivables (including those recognized as a result of tariff harmonization). The Tariff Decree No. 16T, applicable during the second semester of 2020 was issued on November 20, 2020 and published in the Official Gazette on March 20, 2021. This Tariff Decree recognized an aggregated amount of PEC Receivables as of June 30, 2020, equivalent to US$737,234,925. The Tariff Decree No. 19T, applicable during the first semester of 2021 was issued on December 30, 2020 and published in the Official Gazette on May 20, 2021. This Tariff Decree recognized an aggregated amount of PEC Receivables as of September 30, 2020, equivalent to US$856,424,970.

PEC Receivables do not initially accrue interest; however, PEC Receivables remaining unpaid as of January 1, 2026 will accrue interest beginning on that date. The CNE will determine the applicable interest rate as six-month LIBOR, or the equivalent rate that replaces it, plus the spread at the time of application of a Chilean sovereign bond over a US treasury bond, in each case, issued in U.S. Dollars and on similar terms and conditions. The applicable interest rate will be calculated by the CNE.

The Tariff Stabilization Law requires that all PEC Receivables be paid on or before December 31, 2027. Because PEC Receivables are denominated in U.S. Dollars and both PECs and PNLPs are denominated in Pesos, the CNE initially calculates the face value of each PEC Receivable in Pesos and converts it to U.S. Dollars for purposes of recognizing them and tracking their outstanding balances going forward. The CNE converts the amount of a PEC Receivable payable by a DisCo to a generation company generated during a Tariff Period by using the monthly average Observed Exchange Rate for the six-month period prior to the month in which the relevant preliminary technical report is initially intended to be issued under applicable regulation.

Surpluses and Transfer of Surpluses

According to the Independent Market Consultant's projections, the decrease in the electricity prices for regulated clients that can be perceived starting from January 2021 due to the entry of 2015/01 contracts will be captured by the PEC mechanism through a smaller accumulation of debt since that date on. This is related to the Average Nodal Price (PNP), as it will be lower and closer to the PEC price, hence the debt accumulation will be smaller. It is also forecasted that the payments that extinguish said debt accumulation will be paid from 2024 on, with the entry of the contracts of the 2017/01 tendering process. The effect of these contracts increases the difference between the PEC and PNP, which permits the distribution companies to increase their economical surpluses per energy sales, and hence, transfer that sum to the supply contracts that register debt due to the application of the price stabilization mechanism.

Under Article 17 of the Tariff Stabilization Resolution, the CNE is required to calculate the surplus ("*Individual Surplus*") or deficit ("*Individual Deficit*") generated by a DisCo during the preceding Tariff Period as (a) the purchases of electricity made by that DisCo during the applicable Tariff Period valued at the PEC or Adjusted PEC, as applicable, *minus* (b) the purchases made by that DisCo during the applicable Tariff Period valued at the relevant PNLPs,*plus* or *minus*, as applicable, (c) amounts received from or paid to other DisCos during the applicable Tariff Period as a result of certain adjustments applicable among DisCos under the Tariff Stabilization Mechanism that are not related to redistribution of a System Surplus, *minus* (d) the carry-over deficit included in the most recent Tariff Decree, *plus* or *minus*, as applicable, (e) payments made to or received from other DisCos during such Tariff Period resulting from the redistribution of a System Surplus, *minus* (f) payments made by that DisCo to the generation companies during the applicable Tariff Period pursuant to a PEC Receivable Payment Chart *plus* (g) any fines and guaranties collected from the generation companies or the offerors under public supply tenders. See "*—Payment of PEC Receivables.*"

These Individual Surpluses and Individual Deficits are netted together to create system-wide surpluses ("*System Surpluses*") or system-wide deficits ("*System Deficits*"). The CNE is required to set out these Individual Surpluses and/or Individual Deficits and the resulting System Surplus or System Deficit in each preliminary and definitive technical report, and the Ministry of Energy is required to include them in the related Tariff Decree.

If there is a System Deficit, the aggregate amount of the Individual Surpluses will be reallocated on a pro rata basis among the DisCos with Individual Deficits. If there is a System Surplus, each DisCo with Individual Surplus must transfer a *pro rata* portion of its Individual Surplus to DisCos with Individual Deficits. If there is a System Surplus and there are no Individual Deficits, System Surplus there will be allocated among DisCos in proportion to the amounts of PEC Receivables owed by them.

The National Electrical Coordinator is required to publish the PEC Receivable Payment Chart on its website instructing the transfer of Individual Surpluses pursuant to the rules set out above within five Chilean business days following the publication of a Tariff Decree that evidences Individual Surpluses and Individual Deficits.

Tariff Increases

It is the CNE's duty under the Tariff Stabilization Framework to ensure that sufficient surpluses are generated to pay all PEC Receivables in full. The CNE is also required to include in its preliminary and definitive technical reports estimates and projections of future surpluses. Therefore, if in any preliminary or definitive technical report relating to Tariff Periods after December 31, 2024, these estimates and projections do not provide for the full payment of PEC Receivables by December 31, 2027, the CNE must increase the Adjusted PEC applicable from January 1, 2025 through December 31, 2027 by an adjustment factor that will cause sufficient surpluses to be generated to pay all PEC Receivables in full by December 31, 2027. Once the CNE has determined the adjustment factor, it is required to include it in the relevant preliminary and definitive technical reports and the Ministry of Energy is required to include it in the Tariff Decrees covering Tariff Periods beginning January 1, 2025. If the CNE were to fail to apply the adjustment factor, the holder of the PEC Receivables would be entitled to bring the legal actions detailed in "*—Legal Actions*."

If in 2027 the CNE estimates that projected surpluses will not be sufficient to pay all PEC Receivables by December 31, 2027, the CNE may include in the preliminary and definitive technical reports corresponding to 2027 additional amounts in respect of the PEC Receivables whether or not there are Surpluses available to cover those payments. For details see "*—Out-of-pocket Payments*."

Payment of PEC Receivables

After a Tariff Decree is issued setting out surpluses or deficits, the National Electrical Coordinator is required to instruct DisCos to redistribute the existing System Surplus (if applicable, as set out in "*—Surpluses and Transfer of Surpluses*") and make pro rata payments on their respective PEC Receivables to the generation companies. The National Electrical Coordinator issues this instruction in the form of a PEC Receivable Payment Chart (*cuadro de pago de saldos*), which it is required to publish on its website within five Chilean business days after a Tariff Decree setting out any Surpluses is published in the Official Gazette. The PEC Receivable Payment Chart sets out (i) each DisCo required to make a payment, (ii) the generation companies to whom or to whose assignee that payment must be made, and (iii) the PPA to which that payment relates. Payments will be deemed made in the order in which PEC Receivables are recognized.

Upon the issuance of a PEC Receivable Payment Chart, each DisCo listed in that table is required to make all payments set out in that PEC Receivable Payment Chart no later than six Chilean business days after its publication on the National Electrical Coordinator's website. Nevertheless, within three Chilean business days after the publication of a PEC Receivable Payment Chart, each generation company listed on that table is required under the Tariff Stabilization Resolution to invoice the amounts specified in that PEC Receivable Payment Chart plus the applicable VAT to each corresponding DisCo. Only generation companies are permitted to issue these invoices, and assignees of the PEC Receivables must rely on the generation companies to issue them. Although the DisCos are required to pay amounts set out in a PEC Receivable Payment Chart and the assignee of a PEC Receivable may initiate judicial claims to obtain payment and damages irrespective of whether the generation companies issue these invoices, these invoices constitute *títulos ejecutivos*, which permit the generation companies or their assignees to seek payment from the DisCos in expedited judicial proceedings (*juicios ejecutivos*).

DisCos are required to notify the CNE when they make the payments set out in the PEC Receivable Payment Chart, and the CNE is required to update outstanding amounts of PEC Receivables in the PEC Receivable Accrual Chart to be attached to the preliminary and definitive technical reports and the Tariff Decree for the next Tariff Period. Although the PEC Receivables themselves are denominated in U.S. Dollars, the DisCos make payments on the PEC Receivables in Pesos. As a result, the CNE must convert those payments to U.S. Dollars before deducting them from the outstanding amounts of PEC Receivables set out in the next PEC Receivable Accrual Chart. The exchange rate the CNE is required to use for that conversion is the Observed Exchange Rate published on the sixth Chilean business day following the date of publication of the PEC Receivable Payment Chart on the National Electrical Coordinator's website.

Although both the PEC Receivables and the Notes are denominated in U.S. Dollars, payments on the PEC Receivables will be made in Pesos in the amounts published by the National Electrical Coordinator in the applicable PEC Receivable Payment Chart. All payments on the PEC Receivables must be made within six Chilean business days after the publication of the corresponding PEC Receivable Payment Chart. When payments are made, the CNE will convert the Peso-denominated payments made to U.S. Dollars at the Observed Exchange Rate applicable on the sixth Chilean business day following the publication of the corresponding PEC Receivable Payment Chart and use that converted amount to record reductions to the outstanding amount of each PEC Receivable. As long as the Company converts payments received at the same Observed Exchange Rate that the CNE uses to record payments, the Company will be able to limit its exposure to foreign exchange risk.

Out-of-pocket Payments

If in 2027 the CNE estimates that projected surpluses will not be sufficient to pay all PEC Receivables by December 31, 2027, the CNE may include in the preliminary and definitive technical reports corresponding to 2027 additional amounts in respect of the PEC Receivables whether or not there are surpluses available to cover those payments. This would require DisCos to make out-of-pocket payments to cover these amounts. If the CNE includes these additional amounts to be paid in the preliminary and definitive technical reports it issues in 2027, the Ministry of Energy will be required to include those additional amounts in the PEC Receivables recognized in the related Tariff Decrees. Upon the issuance of the Tariff Decrees, the National Electrical Coordinator will publish a PEC Receivable Payment Chart on its website instructing each DisCo to make payments (including those additional amounts) to each applicable generation company.

It is the CNE's duty to ensure the PEC Receivables are paid in full no later than December 31, 2027. If the CNE were to fail to cause sufficient surpluses to be generated to pay all PEC Receivables no later than December 31, 2027, the holder of outstanding PEC Receivables would have a claim for damages against the CNE under general applicable law. See "—*Legal challenges*."

Assignment of PEC Receivables

The Tariff Stabilization Framework permits generation companies to assign their PEC Receivables to third parties; however, for an assignment of the PEC Receivables to be valid and binding in Chile, the applicable generation company and the assignee must enter into a written assignment agreement governed by Chilean law. In addition, the applicable generation company must deliver to the assignee a copy of the Tariff Decree recognizing the applicable PEC Receivable, and a copy of the underlying PPA. Furthermore, it is advisable although not legally required, that the assignment be notified in writing to the CNE.

For the assignment to be enforceable against third parties (including the DisCo that is the obligor of the assigned PEC Receivable), after the execution of each assignment agreement either (a) the DisCo that is the obligor of the assigned PEC Receivables must expressly consent to the assignment, or (b) the assignee must personally notify an authorized officer of that DisCo regarding the assignment of the PEC Receivables through a certifying officer (*ministro de fe*), which notification shall include displaying the title or documents evidencing the Purchased PEC Receivables, with an annotation of the assignment, mentioning who is the assignee and with the signature of the assignor.

In case a DisCo is notified pursuant to (b) in the paragraph above, such DisCo shall be entitled to assert, or reserve its right to assert, against the assignee, defenses or counterclaims it has against the assignor, disputing its payment obligations, within three days after being notified of the assignment of the relevant PEC Receivable. See "*Risk Factors—The PEC Receivables may be subject to defenses or counterclaims by their respective obligors and the face value of the PEC Receivables could be subject to reduction*."

Insolvency Considerations

Chilean Insolvency Law contains claw-back period rules pursuant to which any transfer, encumbrance or other transaction executed or granted by a debtor during the two-year period prior to the commencement of reorganization or liquidation proceedings may be rendered ineffective if it is proved before the court that that transfer, encumbrance or transaction (a) was entered into with the counterparty's knowledge of the debtor's poor business condition; and (b) caused damages to the bankruptcy estate (in other words, was not entered into on terms and conditions similar to those prevalent in the market at the time of its execution) or alters the equality that must prevail among creditors in the insolvency, reorganization or liquidation proceeding.

Nevertheless, certain transfers, encumbrances or other transactions such as pre-payments, payments on terms different than as originally agreed by the parties and the creation of certain security interests (pledge, mortgage, *anticresis*) to guarantee pre-existing obligations executed or granted during the year prior to the commencement of the insolvency proceedings are rendered ineffective. This period can be extended to two years if the transaction was executed with a related party or if it is executed free of charge.

Legal Challenges

As described below, should the DisCos, the CNE, the Ministry of Energy, or the National Electrical Coordinator fail to comply with their obligations or duties or to perform the actions required of them under the Tariff Stabilization Law, the Onshore Collateral Agent could have recourse against each of those parties. Claims arising from a failure to perform periodical actions (such as the issuance of technical reports or Tariff Decrees) would become available from time to time upon such failure to perform. Claims arising from the failure to generate surpluses would become available on December 31, 2027 if, as of that date, Surpluses generated are not sufficient to pay all PEC Receivables in full.

There is limited precedent for claims against Chilean governmental entities for unlawful failure to act (*falta de servicio por omisión*), and there can be no certainty as to what standard Chilean courts will apply in each case. In 2010, Transelec S.A. ("*Transelec*") brought a claim against Chile and the CNE for damages caused by the CNE's failure to issue technical reports and the Ministry of Energy's failure to issue a decree setting out transmission tariffs by the applicable deadline. Transelec argued that because the tariff decree was published about 22 months after the applicable deadline under the Electricity Law, Transelec was not able to collect the increased tariffs that were ultimately enacted. The State Defense Council and the CNE opposed the claim, arguing that the Electricity Law did not establish an express deadline for the issuance and publication of the tariff-setting decree. In addition, they argued that the duration of the tariff setting process was the result of its extreme complexity, high technical difficulty, and unprecedented nature. The Chilean Supreme Court recognized that the Electricity Law did set clear terms for the issuance of the decree and those terms are not subject to the will of the governmental agencies involved; however, the Court found that there was no fault on the part of the governmental agencies and denied the claim for damages, reasoning that the electricity companies, including Transelec, had contributed significantly to the delay by modifying and correcting various aspects of the decree and reports.

CNE

The CNE is the agency in charge of issuing technical reports and ensuring that surpluses are generated in an amount sufficient to pay all PEC Receivables in full no later than December 31, 2027. If the CNE were to fail to perform the actions required of it under the Tariff Stabilization Framework, holders of outstanding PEC Receivables would be entitled to exercise the following remedies against the CNE.

- *Damages.* Holders of outstanding PEC Receivables may bring a claim for damages in Chilean courts against the CNE arising from the failure by the CNE to increase the tariffs in order to generate required Surpluses under the Tariff Stabilization Framework so that PEC Receivables can be paid on or prior to December 31, 2027. Only direct damages, which may include loss of profits, can be claimed and are limited to actual and verifiable damages directly related to CNE's failure to ensure that surpluses are generated. Final compensation amount to be awarded by the Court will depend on the damages that the holder of the PEC Receivables is able to evidence in Court. The claim must be filed before civil courts and the decision is subject to appeal before the competent Court of Appeals and eventually certain exceptional remedies against the Chilean Supreme Court.

To the extent the claim for damages is admitted, recourse will be limited to CNE's assets and in case such assets are not sufficient to compensate the PEC Receivable holder, the Chilean government or Chilean Congress could provide the CNE additional funds to fulfill its obligations through future annual budgetary laws.

- *Petition to the Comptroller General*. Holders of outstanding PEC Receivables may request that the Comptroller General (a) instruct the CNE to perform any required actions it failed to perform and (b) bring administrative claims against the applicable public officials. Although actions to enforce the decisions of the Comptroller General cannot be brought in Chilean courts, Governmental Authorities are legally required to follow the Comptroller General's instructions.

- *Recurso de protección.* Holders of outstanding PEC Receivables may petition the competent Court of Appeals for an injunction (*recurso de protección*) recognized by the Chilean Constitution to uphold certain constitutional rights such as the right to property, the right to develop a lawful economic activity, among others. This petition must be filed directly before the competent Court of Appeals within 30 days after the alleged violation of the petitioner's fundamental right, which would occur after the time period has lapsed for approving the application of an increase factor. Judgments of the Court of Appeals are subject to appeal before the Chilean Supreme Court.

- *Administrative proceedings*. If a definitive technical report were to violate the law, contain errors or lack required information, holders of the PEC Receivables would be entitled to file administrative claims for the amendment of the definitive technical report. The most common administrative claim is the *recurso de reposición* which must be filed within five Chilean business days as of the publication of the final report.

The actions required to be performed by the CNE, whose non-performance would give rise to these remedies are its obligations to:

- the issuance of the preliminary and definitive technical reports; and

- the application of an adjustment factor seeking to increase tariffs (a) if PEC Receivables are expected to exceed an aggregate amount of US$1,350 million after June 30, 2023 so that PEC Receivables cease to accumulate beyond that date (b) and between 2025 and 2027 if required, based on the CNE's projections, to ensure that sufficient Surpluses are generated to permit all PEC Receivables to be paid by December 31, 2027.

Ministry of Energy

If the Ministry of Energy (i) fails to issue Tariff Decrees on a semi-annual basis and on or prior to the applicable deadlines (provided that the CNE has issued the applicable preliminary and definitive technical reports) or (ii) issues a Tariff Decree that violates the law, contains errors or lacks required information, beneficiaries of outstanding PEC Receivables would have the same recourse against the Ministry of Energy as against the CNE. However, unlike CNE, the claim for damages will be directed to the assets of Chile.

Comptroller General

Historically, the Comptroller General has not been the subject of legal claims from affected parties; however, if the Comptroller General fails to approve a Tariff Decree that complies with all legal requirements within the required timeframe (15 Chilean business days after the submission of the Tariff Decree, extendable for an additional 15 Chilean business days) beneficiaries of outstanding PEC Receivables would have recourse for damages and standing to file for a constitutional injunction (*recurso de protección*) against the Comptroller General on the same terms as against the Ministry of Energy. Given the absence of precedent, the outcome of these claims is uncertain.

National Electrical Coordinator

If the National Electrical Coordinator fails to issue the PEC Receivable Payment Chart on or prior to the applicable deadline or if a PEC Receivable Payment Chart contains inaccuracies, holders of outstanding PEC

Receivables would be entitled to file a claim for damages against the National Electrical Coordinator under general principles of Chilean Law. To the extent the claim for damages is admitted, recourse will be limited to the National Electrical Coordinator's assets.

In addition, if a PEC Receivable Payment Chart contains errors and the affected party is a generation company, a DisCo or a transmission company (a "*coordinated entity*"), the affected party would be entitled to bring a claim before the Experts' Panel within 15 Chilean business days after the publication of the PEC Receivable Payment Chart on the National Electrical Coordinator's website. Beneficiaries of PEC Receivables that are not coordinated entities would be entitled to participate in the process as interested parties supporting the position of a coordinated entity that is part of the procedure, but they would not be permitted to initiate those proceedings or file claims thereunder. Claims filed with the Experts' Panel will not suspend the DisCos' payment obligations and, therefore, if any additional payments or reimbursements are required as a result of the Experts' Panel's decision, these additional payments or reimbursements must be made after such decision is handed down. The decision of the Experts' Panel is not subject to appeals or further remedies, unless the decision exceeds the Experts' Panel's competence under the Electricity Law, in which case the Ministry of Energy may declare it inapplicable. According to the Electricity Law, the Experts' Panel may only decide between the positions submitted by the parties to the discrepancy and may not adopt a middle-ground decision.

DisCos

A DisCo's obligation to make payments on its PEC Receivables arises from the Tariff Decree recognizing the generation of such PEC Receivables. The timing of those payments will be determined by the National Electrical Coordinator's issuance of the PEC Receivable Payment Charts.

If a DisCo fails to make a required payment within six Chilean business days after the publication of a PEC Receivable Payment Chart on the National Electrical Coordinator's website, beneficiaries of the PEC Receivables for which that DisCo is the obligor will be permitted to bring civil court proceedings against that DisCo or administrative proceedings before the Chilean Superintendency of Electricity. These administrative proceedings could take at least six months to be resolved and would require that the Superintendency of Electricity find a specific breach of electricity regulations. They would also be subject to administrative claims and appeals as well as any defenses available to the DisCos under Chilean law. See "*Risk Factors—Risks Relating to the PEC Receivables.*"

In addition, if a generation company has issued an invoice to a DisCo for the amount of a PEC Receivable and either (i) assigned the "fourth copy" of that invoice to the beneficiary of that PEC Receivable, if the invoice is a physical one, or (ii) assigned the electronic invoice in accordance with article 9 of Chilean Law No. 19,983, the beneficiary of that PEC Receivable will be permitted to bring an expedited proceeding in civil court (*juicio ejecutivo*) against the DisCo for failure to make payment on that invoice.

In addition, in the event of the insolvency of an Obligor, invoices issued by the generation companies to DisCos after the publication of a PEC Receivable Payment Chart may eventually benefit from the priority of payment defined in Article 72 of Law No. 20.720 upon the start of a judicial reorganization of the DisCo provided that the generation company has agreed to maintain its supply of energy, the invoices are issued no more than eight days prior to the date of the court order that approves the reorganization petition filed by the DisCo, the aggregate amount of all claims from suppliers with this priority of payment does not exceed from 20% of the total indebtedness of the DisCo, and all of these circumstances are certified by the reorganization trustee (*veedor*) in the context of a reorganization proceeding. This preference of payment is a special benefit that applies to certain suppliers of the reorganized company during the financial protection period, while a judicial restructuring proceeding is negotiated and would only be available to the extent the DisCo is involved in a judicial restructuring proceeding. For additional information on judicial restructuring proceedings, see "*—Insolvency Regime (Law No. 20,720 and Electricity Law)—Judicial Reorganization Proceedings*."

Chilean Government's New Energy Agenda

In September 2015, with the participation of the government, several stakeholders, key participants in the energy sector, universities and the public at large, the Ministry of Energy produced and issued a document titled "Energy 2050", which contains Chile's long-term energy policy, defining what should be the Chilean energy matrix for the years 2035 and 2050 (the "*Energy Policy 2050*", which is available at http://www.energia2050.cl/en/energy-2050/energy-2050-chiles-energy-policy/).

The Energy Policy 2050 is based on four principles identified as: (i) quality and security of supply (i.e. reliability); (ii) energy as a driving force for development (i.e. inclusiveness and social sustainability); (iii) environmentally friendly energy (i.e. environmental protection and sustainability); and (iv) energy efficiency and energy education (i.e. competitiveness, efficiency and public awareness).

Within the framework of the Energy Policy 2050, the Ministry of Energy has developed a short-term energy policy known as "*Ruta Energética: liderando la modernizacion con sello ciudadano*" (Energy Route: leading modernization to help energy serve the citizens and improve the quality of life), which addresses the following seven main focus areas: energy modernization, the social impact of energy, energy development, low emission energy, sustainable transport, energy efficiency and energy education and training. To achieve its goals, this agenda contains 10 commitments, which include:

(i) to create a map detailing the country's energy vulnerabilities, and identifying families that do not have access to electricity or other energy services, with a view to addressing the existing gaps;

(ii) to modernize the institutional framework for energy regulation and to increase government efficiency so that the government may provide better service, in particular the through the mandate of the Superintendence of Electricity and the Chilean Nuclear Energy Commission;

(iii) to reduce the processing times for environmental projects under this agenda by 25%;

(iv) to reach four times the current capacity of renewable small-scale (less than 300 KW) distribution generators by 2022;

(v) to increase by at least ten times the number of electric vehicles that circulate in the country;

(vi) to modernize the regulation of electricity distribution through a participatory process;

(vii) to regulate solid biofuels, such as firewood and its derivatives, granting the Ministry of Energy the necessary authority to establish technical specifications and regulations for the commercialization of firewood in urban areas;

(viii) to establish a regulatory framework for energy efficiency that generates the necessary incentives to promote the efficient use of energy in the sectors of greater consumption (industry and mining, transport and buildings);

(ix) to start the process of moving away from carbon-based energy sources through the reconversion of coal- fired plants, and the introduction of concrete measures in electric-powered drive trains; and

(x) to qualify 6,000 workers, technicians and professionals for jobs in the energy industry by helping them developing skills and abilities in the management and sustainable use of energy, in the electricity, fuel and renewable energy sectors.

In late 2018, the Ministry of Energy and the Ministry of the Environment initiated negotiations with generation companies with the purpose of implementing a decarbonization process of the Chilean energy matrix. The goal of the government is to progressively close all coal-fired thermoelectric power plants by 2040, which is the year when Chile expects to become a carbon-neutral country. In June 2019, the Government and the main generation companies entered into voluntary agreements by means of which the oldest eight thermoelectric plants (representing 1,047 MW of installed capacity) will stop their regular operations by year 2024. In December 2019, the Ministry of Energy announced agreement according to which another two coal-fired thermoelectric power plants by the end of 2024.

Environmental Regulations

Chile has numerous national environmental statutes, regulations, decrees and municipal ordinances that govern our operations. Among others, there are regulations relating to industrial zoning, waste management, industrial wastewater, air emissions, hazardous substances storage, environmental liability and cleanup of contamination, where there are risks to public health, etc. Under these rules, we have been and may be required to obtain specific approvals, consents and permits, while emissions and discharges from our operations may be required to meet specific standards and limitations set forth in regulations or permits. We have made and will continue to make substantial expenditures to comply with such environmental laws, regulations, decrees and ordinances. See "*Risk Factors—Risk Factors Related to our Business in General—Compliance with environmental regulations may require significant expenditures that could adversely affect our results of operations*."

The Environmental Law, sets up a framework for environmental regulation in Chile, which has become increasingly stringent in recent years. This law has created an institutional framework comprised by: (i) the Ministry of Environment (*Ministerio del Medio Ambiente*); (ii) the Council of Ministers for Sustainability (*Consejo de Ministros para la Sustentabilidad*); (iii) the Environmental Assessment Service (*Servicio de Evaluación Ambiental*); and (iv) the Chilean Environmental Enforcement and Compliance Superintendency (*Superintendencia del Medio Ambiente*), all of which will be in charge of regulating, evaluating and enforcing activities that feature environmental impacts. These institutions, which replaced their predecessor, the National Environmental Commission (*Comisión Nacional del Medio Ambiente*), are currently fully operational. In addition, the newly established Environmental Courts (*Tribunales Ambientales*) created and regulated by Law No. 20,600, are responsible for the judicial review of environmental decision making. Additionally, there are more than 20 public services with environmental capabilities, including *Servicio Nacional de Pesca*, *Servicio Nacional de Turismo*, *Consejo de Monumentos Nacionales*, *Autoridad Marítima*, *Autoridad Sanitaria*, *Dirección General de Aguas* (DGA), *Servicio Agrícola Ganadero* (SAG), *Corporación Nacional Forestal* (CONAF), *Ministerio de Bienes Nacionales*, *Servicio Nacional de Geología y Minas*, among others.

Violations of these environmental regulations may lead to significant fines, the closure of facilities and the revocation of environmental approvals. The Environmental Law and its regulations allow the Chilean government, through the State Defense Council (*Consejo de Defensa del Estado*), the local councils (for acts occurring within their respective jurisdictions) and affected citizens, to bring judicial action in case of environmental liability arising from industrial contamination.

Additionally, citizens affected by any environmental decision-making process may petition for relief to a Chilean Court of Appeals of the relevant jurisdiction, which has the power to require the suspension of the offending activity and to adopt protective measures through a protection remedy (*recurso de protección*). This has been a widely utilized tool to obstruct and/or to delay projects, especially large ones such as thermoelectric plants. Citizens also have other types of judicial and administrative actions that they can use to oppose an environmental decision.

Environmental Considerations with respect to Electricity Projects

The Environmental Law provides that certain projects and activities mayonly be carried out or modified only once their environmental impact has been properly assessed. Accordingly, *"high voltage transmission lines with a tension higher than 23kV"* and *"electric power generating plants over 3 MW"* must be environmentally assessed. Therefore, distribution projects that are equal to or less than 23kV are excluded from this (unless an environmental impact assessment is triggered based on other general criteria, such as location). However, these projects need to apply and obtain certain sectorial specific permits to allow their construction and further operation. Applicable permits depend on the specific features of the project, such as the facilities and conditions related to its construction (municipal permit for the temporary working facilities, sanitary authorizations for the water supply and for the sewage and waste management, permit for the equipment transportation, etc. may be needed) and the area where it is located (archaeological permit to perform excavations, zoning permit, permit to intervene water course, forest management plan for native forest felling, among others, may be needed).

According to the abovementioned, projects or their significant modifications with the characteristics set out in the Environmental Law must be submitted to an administrative procedure aimed at assessing the environmental impacts of projects, the Environmental Evaluation Impact System (*Sistema de Evaluación de Impacto Ambiental* or

"*SEIA*"). The SEIA is under the supervision of the Environmental Assessment Service ("*SEA*"), and the corresponding project may be submitted by means of an Environmental Impact Declaration ("*EID*") or an Environmental Impact Study ("*EIS*"), depending on the magnitude of the environmental impacts generated thereof.

With regards to community participation, in the EIS assessment procedure (as well as in the EID procedure, in the event that certain conditions are met), there is a phase, in which both directly affected people and non-governmental organizations (NGOs) may participate. Within the participation phase, citizens are allowed to submit their observations to the project that is under environmental impact assessment. Citizens' observations are not binding for the project's holder nor for the governmental authority evaluating the project, but each observation must be duly addressed by the relevant governmental authority (provided that it meets specific formalities). The submission of observations within the environmental impact assessment of a project allows citizens to challenge the Environmental Approval Resolution ("*RCA*") of the project before the relevant governmental authority and, then, before the Environmental Court, based on the illegality of the RCA, if such grounds exist.

The environmental assessment procedure concludes with a RCA issued by corresponding Regional Environmental Assessment Commission or the SEA's Executive Director, depending on the location of the project, certifying that a project complies with all applicable environmental laws and regulations and entitles the project owner to obtain, from any public agencies, the applicable environmental sectorial permits related to specific environmental components detailed in the RCA. In this regard, once the RCA is granted, the environmental permits may not be denied for environmental reasons, although they may be rejected based on technical grounds (which are related to the specific regulatory body, such as archaeological regulations, in case of excavations; health standards, in case of water supply or waste management; hydraulic works regulation, in case of water course intervention; among others). Rejection of environmentally-approved projects based on technical grounds are related to cases in which the project's holder does not meet the sectorial applicable standard. For example, if a transmission line goes through a native forest, the project's holder will have to perform forest felling, which has to be authorized by the CONAF based on the technical suitability of the area where the forest compensation will take place, the season in which the activities are going to be executed, the technical reports of the forest that the project's holder provides the authority with, etc. Likewise, if a transmission line goes through an archaeological site, the project's holder will have to meet certain requirements related to the rescue of the archaeological findings, hire an archaeologist to oversee the construction of the line, report to the National Monuments Counsel in case of an archaeological finding, etc. If the project's holder does not comply with these obligations, the applicable permit (although it was environmentally-approved) may be technically rejected.

Project owners not obliged to evaluate their projects under the SEIA may request an official pronouncement from the relevant regional office of the SEA on whether the execution or amendment of a project must be submitted to the SEIA. This request is known as a "*Pertinence Consultation*" (*Consulta de Pertinencia*). A Pertinence Consultation provides the project owner with an official response issued by the SEA regarding the obligation, or lack thereof, of carrying out an environmental impact assessment of the project (or its amendment) prior its execution.

Bankruptcy Regime

The Bankruptcy Law replaced the former Chilean bankruptcy regime (created in 1982) for a law of "reorganization and liquidation" of companies and individuals. This law entered into effect on October 9, 2014, establishing various rules that seek to avoid bankruptcy of individuals and companies in a more pro-business approach. In connection with the electric industry, the Electricity Law established a special liquidation proceeding for electricity companies by including the participation of the Superintendency of Electricity and the CNE in the process.

There are three different insolvency proceedings available for a company under the Chilean Insolvency Law: (i) the judicial reorganization proceeding; (ii) the pre-packaged reorganization agreements and (iii) the liquidation proceedings (voluntary or compulsory).

Judicial Reorganization Proceedings

The judicial reorganization proceeding is an insolvency proceeding in which the debtor requests from a court a period of insolvency protection, in order to negotiate with its creditors a restructuring of its assets and liabilities. The debtor is protected by law while negotiating, and such protection ends with the approval or rejection of a reorganization agreement. A reorganization trustee (*veedor*) is appointed by the three largest creditors to oversee the proceedings.

The approval of the agreement requires the vote of 2/3 of the creditors and claims on each class of creditors with voting rights. If the debtor fails to reach an agreement with its creditors, a liquidation proceeding is automatically initiated. In the event of reorganization, the management of the company would continue in place while a restructuring proposal is discussed with creditors. The court will declare the liquidation of the company (or sale of assets as a whole economic unit, as mentioned later in the text) only if the debtor fails to reach an agreement with its creditors.

Pre-packaged Reorganization Agreements

The Bankruptcy Law also provides for the possibility of a pre-packaged reorganization agreement between the debtor and two or more creditors representing 75% of the total debt with voting rights. In this case, the already signed pre-packaged agreement must be filed in court requesting the approval of the court. The court can immediately approve the pre-packaged agreement or summon the creditors to a special creditors' meeting to ratify the pre-packaged agreement.

Liquidation Proceedings

The liquidation proceeding is primarily a procedure for the orderly liquidation and winding up of a debtor. Its main purpose is to liquidate in a single procedure all assets pertaining to an individual or legal entity, in order to pay its debts to its creditors. Notwithstanding the above, it may be possible to continue with the business of the debtor under specific conditions, as further discussed below.

A liquidation proceeding may be voluntary in case the debtor files for its own liquidation or compulsory or involuntary in case a creditor requests such declaration. In the case of a compulsory or involuntary declaration, there would be a proceeding to incorporate evidence and to have a court determination of insolvency. After that, the court will issue a final decision declaring or not the liquidation of the debtor. Since the issuance of the liquidation decision, the administration of the assets of the debtor will pass to a trustee (*liquidador*) appointed by the three largest creditors, who will be in charge of liquidating the debtor's assets and of paying creditors with its proceeds.

The Electricity Law includes a series of special rules governing a liquidation proceeding of a generation, transmission or distribution company. The Electricity Law provides that immediately after a request is submitted to initiate a liquidation proceeding against an electricity company, that request must be relayed by the relevant court to the CNE and the Superintendency of Electricity, which shall provide their opinion as to whether the liquidation proceeding would compromise the sufficiency of the electricity distribution system, seen as the probability of satisfying demand, or the basic standards of operation of the electricity distribution system, including the safety of the system, economic operation, and open access to the transmission system.

If the court finds that the sufficiency of the electricity distribution system or its basic standards of operation are compromised, it must instruct the definitive continuance of the insolvent electricity company's economic activities, and appoint a provisional administrator, nominated by the Superintendency of Electricity. Under the Electricity Law, as soon as the provisional administrator assumes its position, it must prepare and make available to the court a list of the company's assets required for the business continuation and also the assets required to ensure the sufficiency of the system and the basic standards of the operation.

If the court decides that the liquidation of the electricity company would affect the safety, efficient operation, free access or sufficiency of an electric system, the assets of the electricity company shall be sold as an economic unit (*unidad económica*). The Electricity Law sets forth that the court resolution that instructs the business continuation suspends the right of creditors secured with pledges and mortgages to initiate and continue individual foreclosure proceedings against the electricity company. This provision is intended to facilitate the sale of the assets as a whole "economic unit" (*unidad económica*) and enable the acquirer to develop and maintain the insolvent company's ordinary course of business. Such sale as a whole "economic unit" shall include all assets proposed by the provisional administrator as necessary for the business continuation, as approved by the Superintendency of Electricity. In case of discrepancies with the creditors regarding the assets included in the sale, the ultimate decision shall be made by the court (following the advice by the Superintendency of Electricity and the CNE), in a manner that guarantees the safety, efficient operation, free access and sufficiency of an electric system. Therefore, such sale should include the relevant distribution concession as the exploitation of the distribution service is not allowed without the existence of a distribution concession. The sale of the assets as a whole "economic unit" must take place within 18 months as from the resolution of liquidation is *res judicata* (*causa ejecutoria*). Creditors representing more than 50% of the voting debt could request the court to establish different rules for the sale, in which case the court shall consult with the Superintendency of Electricity and the CNE in order to rule in a form that does not compromise the sufficiency of the system or the basic standards of operation.

New Constitution and Legislative Agenda

On October 25, 2020, a constitutional referendum was held, where nearly 80% of voters elected to replace the Chilean Constitution which will be drafted by a special constitutional convention comprised of 155 citizens elected for that task only. The citizen members of the special constitutional convention were elected on May 15 and 16, 2021, and the special constitutional convention is expected to deliver a final draft of the new constitution within a period of nine months from its inauguration (which is expected to take place no later than the first week of July 2021), which can be further extended up to a total of twelve months from its inauguration. Among the elected members, the majority group is of those who are independent to political parties, and virtually all sides of the political spectrum are represented (including 17 members representatives of indigenous communities). Additionally, there are 77 women and 78 men among the elected members (as a result of the gender equality regulations governing the election). The final draft of the new Chilean Constitution will be submitted to a further public referendum for its approval by simple majority vote (where the referendum will be of mandatory vote), which is expected to take place around mid-2022.

On November 20, 2019, as part of the deliberations relating to the Chilean budget law for 2020, the Chilean government and the Senate agreed to introduce a series of measures, including: (i) a 50% increase in government-subsidized pensions for elderly citizens over 80 years of age effective from January 2020; a 30% increase in government-subsidized pensions for elderly citizens aged 75 to 79 effective from January 2020 and rising to 50% by January 2021; a 25% increase in government-subsidized pensions for elderly citizens aged under 75 effective as of January 2020, rising to 40% by January 2021 and 50% by January 2022; (ii) a 50% reduction in public transportation fares for elderly citizens over 65 years of age; (iii) an increase in the per capita expenditure for the Primary Health Care Services (*Atención Primaria de Salud*); (iv) an online platform for the purchase of medication at the price determined by National Supply Warehouse (*Central Nacional de Abastecimiento*) and (v) an exemption from customs taxes for the import of donated organs. A number of the foregoing measures have been enacted as laws, while others are subject of parliamentary discussions. Furthermore, the 2020 Budget Law allocates expenditures to fund the rescheduling of student loans as well as the forbearance of penalty interest and related collection expenses.

As a result of the Social Agenda, the Tariff Stabilization Law was enacted in November 2019. This law stablished a stabilization mechanism for energy and power prices that regulated customers pay to distribution companies by bringing forward the projected reduction in supply prices for the years to come, meant to occur by the entry into force of new contracts that resulted from the last calls for CNE tenders of electricity. See "—*Tariff Stabilization Framework.*"

In December 2019, the Minister of Finance announced the Employment Protection and Economic Recovery Plan (the "*Recovery Plan*"), aimed at supporting economic recovery by strengthening employment protection, boosting public investment, supporting small- and medium sized companies and the reconstruction of urban infrastructure following widespread demonstrations that took place in Chile from October to December 2019. The total cost of the Recovery Plan is expected to amount to US$5.5 billion.

On January 15, 2020, the President of Chile announced a scheme of comprehensive reforms aimed at improving the Chilean pension system. If the Chilean Congress approves the proposed reforms, Chile's reformed pension system would be funded through a combination of contributions from the state, employers and workers. Pursuant to the proposed reforms, which are to be implemented gradually, an additional 3% contribution from employers will complement workers' contributions to their retirement fund (*Ahorro Previsional Personal*). In addition, a further 3% additional contribution (comprising a 2.8% contribution to the state-administered Collective and Solidary Retirement Fund (*Fondo de Ahorro Colectivo y Solidario*) and a 0.2% contribution to finance dependency insurance policies) will be borne by employers, with state support. The funds collected through this further 3% contribution will be used to provide financial support to current and future retirees, particularly benefitting women, middle-class-income citizens and dependent elderly citizens. The proposed additional contributions would be managed by an autonomous public institution and be in addition to the current 10% contribution, which will remain under the management of private pension fund managers (AFPs).

If the proposed reform is approved by the Chilean Congress, male retirees who have made contributions for a minimum of twelve years will have their pensions increased, on a monthly basis, by UF2 (approximately Ch$58,141 as of December 31, 2020), and female retirees who have made contributions for a minimum of eight years will have their pensions increased, on a monthly basis, by UF2.5 (approximately Ch$72,676 as of December 31, 2020). Such changes will result in an average 20% pension increase for male citizens, benefitting more than 500,000 retirees, and an average 32% pension increase for female citizens, benefitting more than 350,000 retirees.

COVID-19 Outbreak

Beginning March 2020, the Chilean government, the Central Bank and the CMF announced a series of measures aimed at mitigating the effects that the COVID-19 might have in the Chilean economy. On April 2, 2020, following the COVID-19 outbreak, the Central Bank published its monetary policy report for the month of March, modifying its GDP forecasts. The Central Bank estimated a GDP contraction ranging between 5.5% and 7.5% of GDP for 2020, a GDP growth ranging between 4.75% and 6.25% for 2021 and between 3.0% and 4.0% for 2022. While these forecasts for the Chilean economy might have been reasonable when formulated, actual outcomes depend on future events. Accordingly, we can give no assurance that economic results will not differ materially from the information set forth above.

On March 19, 2020, the President of Chile announced a series of extraordinary economic relief measures aimed at protecting health, salaries and employment in light of the COVID-19 outbreak and its impact on the global economy (the "*Coronavirus Plan*"), which some of them have been approved by the Chilean Congress. The total cost of the Coronavirus Plan is expected to be US$11.75 billion and includes the following measures: (i) a 2% increase in public health expenditures; (ii) a guarantee on the payment of salaries (to be borne by the Unemployment Solidarity Fund (*Fondo de Cesantía Solidario*)) to employees that, due to the COVID-19 emergency, must stay at home and are unable to work remotely; (iii) the immediate discussion in Congress of an employment protection act (the "*Unemployment Protection Act*"), which provides for a reduction in workday hours and the use of funds from the Unemployment Solidarity Fund to offset the corresponding wage reductions; (iv) subsidies amounting to US$130 million, to be granted to approximately 2 million informal sector employees; (v) the establishment of a US$100 million solidarity fund to attend social emergencies derived from a decrease in micro-enterprises' sales; (vi) a three-month suspension of suspension of provisional monthly payments (PPM) of corporate income tax; (vii) a three-month postponement in VAT payments by companies with monthly sales under UF350,000 (US$11.8 million as of March 19, 2020); (viii) a deferral until July 2020 on the payment of 2019 income tax by small- and medium-sized companies; (ix) a deferral in the payment of workers' contributions by companies with monthly sales under UF350,000 or by individuals with properties valued under CLP133 million; (x) a reduction to 0% in the stamp tax rate for a six-month period; (xi) relief measures on overdue tax payments, including flexible repayment facilities and a temporary stay in collections; (xii) a right to deduct corporate costs associated to COVID-19; (xiii) the payment in cash of all outstanding invoices issued to the Chilean government and pending payment and the payment of all invoices issued to the Chilean government in the future within 30 days; and (xiv) a US$500 million capital contribution to BancoEstado to expand its lending operations. On March 22, 2020, the Chilean government imposed a nighttime curfew to reduce the number of COVID- 19 infections.

On March 23, 2020, the CMF adopted additional measures to ensure greater flexibility for the financial system in the context of the COVID-19 pandemic, including: (i) an authorization for banks to reschedule the payment of up to three mortgage loans' installments without additional credit provisions; (ii) an authorization for banks to extend up to six months the maturity of consumer and small and medium-sized enterprises loans, which shall not be considered as a renegotiation for provisioning purposes; (iii) an authorization for banks to use mortgage guarantees' surpluses to secure credits for small- and medium- sized enterprises; (iv) an 18-month extension on the period in which banks may sell goods received as payment in kind; and (v) a modification to the treatment of the cash amount that banks must post as collateral for the variation margin of bilaterally cleared derivative transactions, allowing for the value of the derivative to be offset against the amount pledged as collateral.

In addition, on March 23, 2020, the Central Bank announced a series of measures aimed at providing liquidity to the Chilean economy and support credit, including a credit facility (Conditional Credit Facility for Incremental Placements) for banking entities to continue financing and refinancing loans to households and companies, especially those that do not have access to the capital market. To access this credit facility, banking entities have to pledge: (i) their holdings of Central Bank or Treasury debt securities; (ii) fixed interest debt securities held (except for subordinated or non-maturing bonds); or (iii) other debt securities registered with the CMF that meet the Central Banks' risk conditions. Additionally, the Central Bank announced the relaxation of liquidity requirements for banking entities. For this purpose, the Compendium of Financial Rules will be modified to expressly consider that in situations of national emergency or other serious exceptional circumstances, the Council of the Central Bank may, at its sole discretion, relax or suspend the application of the existing liquidity limits.

On April 8, 2020, the President announced a second stage of the Coronavirus Plan. The total cost of the Coronavirus Plan (including this second stage) includes the following measures: (i) the creation of a US$2.0 billion fund to provide greater benefits and create more jobs for vulnerable individuals, especially aimed to benefit 2.6 million informal workers without unemployment insurance; and (ii) support to small and medium-sized enterprises and business in financial distress through lines of credit guaranteed by the Chilean government, covering 85% of the loan and in an aggregate amount of up to US$24 billion. These financing will be for a period of up to 48 months, with a grace period of up to six more months, and may equal as much as three months of a company's sales.

On April 8, 2020, the Central Bank announced a series of complementary measures aimed at providing liquidity to the Chilean economy and support credit, particularly to companies that have seen their cash flows severely affected as a result of the COVID-19 outbreak. In addition, the Central Bank announced an extension of financial services offered by the Central Bank to non-banking entities, aimed at ensuring the continuity of their payment obligations. Further, an additional line of credit will be available under the Conditional Credit Facility for Incremental Placements for a total aggregate amount of US$24 billion, providing loans at the monetary policy rate (0.50%) to those banking entities that provide lines of credit guaranteed by the Chilean government pursuant to the measures announced by the President (as described above).

Further, the Chilean government and the Central Bank announced their intention to send a bill proposal to Congress authorizing the Central Bank to offer financial services, such as access to current accounts and liquidity facilities, to non-banking entities, including savings and credit cooperatives, central counterparty entities, securities clearing houses and high value payment systems, provided that these entities comply with the regulations and supervision standards applicable to the provision of these services.

Following the announcement on April 8, 2020, on April 12, 2020, the President announced the framework of terms and conditions for the management of credit lines guaranteed by the Chilean government aimed at facilitating companies' access to working capital loans. This framework would allow guarantees for new loans of up to US$24 million and complement the capitalization of the small businesses guarantee fund ("*FOGAPE Fund*"), for an amount of US$3 billion. This framework has been coordinated with complementary actions by the Central Bank and the CMF. The central elements of the framework are: (i) credit lines for working capital for an amount equal to as much as three months of a company's sales for companies with annual sales of up to 1 million UF; (ii) financings will be for a period of up to 48 months, with a grace period of up to six more months; (iii) loans will have a maximum interest rate of the monetary policy rate plus 3% (as of the date of this offering memorandum, the current real interest rate is equivalent to 0%); (iv) banks shall offer this credit line in a massive, expeditious and standardized way to reach the expected 1.3 million potential beneficiaries with weekly reports from the Banks on applications and approvals to monitor compliance with this commitment and the transparency of the process; (v) for entities requesting these credit lines, banks will postpone any repayments of other pre-existing loans for at least 6 months, in order to relieve the financial burden; (vi) basic eligibility criteria the client has not filed for insolvency proceedings, and is not delinquent on loan payments for more than 30 days as of March 30, 2020, or as of October 30, 2019 for companies with sales below UF25,000.

On August 20 and September 8, 2020, the Chilean Congress enacted Laws No. 21,253 and 21,265 respectively. According to this new legislation, the Central Bank is allowed to buy and sell Treasury debt instruments in the secondary market under exceptional and transitory circumstances only, to prevent financial volatility (but not to finance the government). To execute these measures, the Chilean Central Bank requires the approval of at least 4 of its 5 board members.

In addition, a bill proposal to capitalize the FOGAPE Fund with US$3 billion was approved by the Chilean Congress.

MANAGEMENT

ILAP is a limited liability company (*sociedad de responsabilidad limitada*) organized under the laws of Chile. The business address of our executive officers is at Cerro El Plomo 5.680, oficina 1202, Las Condes, Santiago, Chile.

ILAP does not have a board of directors and is managed by LAP Chile, a corporation (*sociedad anónima*) organized under the laws of Chile, which has ample powers to control and manage ILAP pursuant to its by-laws. LAP Chile designated an experienced management team with deep renewable energy industry expertise as plenipotentiary managers/attorneys-in-fact for ILAP. In prior roles, the management team members have been responsible for the development and financing of wind and hydro projects throughout Latin America for several energy related companies or energy focused financial firms.

Set forth below is a brief biographical description of the members of ILAP's management team:

Diego Hollweck. Mr. Hollweck is the General Manager of LAP Chile. He received a degree in Economics and a master's degree in Corporate Finance and Capital Markets from the University of Buenos Aires. With more than 22 years of experience in the energy sector, he became CEO of LAP Chile at the beginning of 2018, after having worked in senior positions in different international energy companies and investment funds such as BG Group and Duke Energy. Mr. Hollweck is currently second vice-president of Generadoras de Chile, a trade association formed by the largest power generation companies in the country.

Esteban Moraga. Mr. Moraga is the Chief Financial Officer of LAP Chile. He received a degree in Commercial Engineering and a master's in Finance from Universidad Adolfo Ibañez. He has more than 12 years of experience as CFO in various industries including Tobacco, Industrial Logistics, Construction, Ports and Energy. He became CFO at LAP Chile in 2017, after having worked in the British American Tobacco Chile company and serving as CFO in different companies of the Ultramar group related to the port infrastructure industry (Full Pak, ATCO Sabinco, Puerto Angamos & TGN).

Oscar Morales: Mr. Morales is the Commercial Manager of LAP Chile. Mr. Morales received a degree in Electrical Engineer from the Simon Bolivar University in Venezuela, and later a Master in Energy Economics from the Comahue University in Argentina. He has more than 25 years of experience in the electrical industry, where he has served as a consultant for electricity markets and as a professional in commercial departments of electricity companies in Venezuela, Chile and Peru. He became Commercial Manager at LAP in March 2021, after having worked in different energy consulting companies in Chile and Venezuela, leading and executing tasks in the areas of operation and regulation, among these companies are ASINCRO and EDELCA in Venezuela, Energetica and Systep in Chile.

Claudio Gutierrez. Mr. Gutierrez is the O&M Manager of LAP Chile. Mr. Gutierrez received a degree in Electrical Engineer from the University of Zulia in Venezuela. He has more than 15 years of experience in the electrical industry, including working in project management in countries such as Venezuela, Argentina, Peru and Chile and leading various stages of the business such as development, construction, and operation and maintenance. Mr. Gutierrez has participated in the operation of 11 projects related to power generation and transmission, including wind farms, solar plants, hydroelectric power plants and transmission lines in Chile, Peru, Venezuela and Argentina. He joined the LAP Chile during 2015 as O&M Engineer and after 2 years he become O&M Manager.

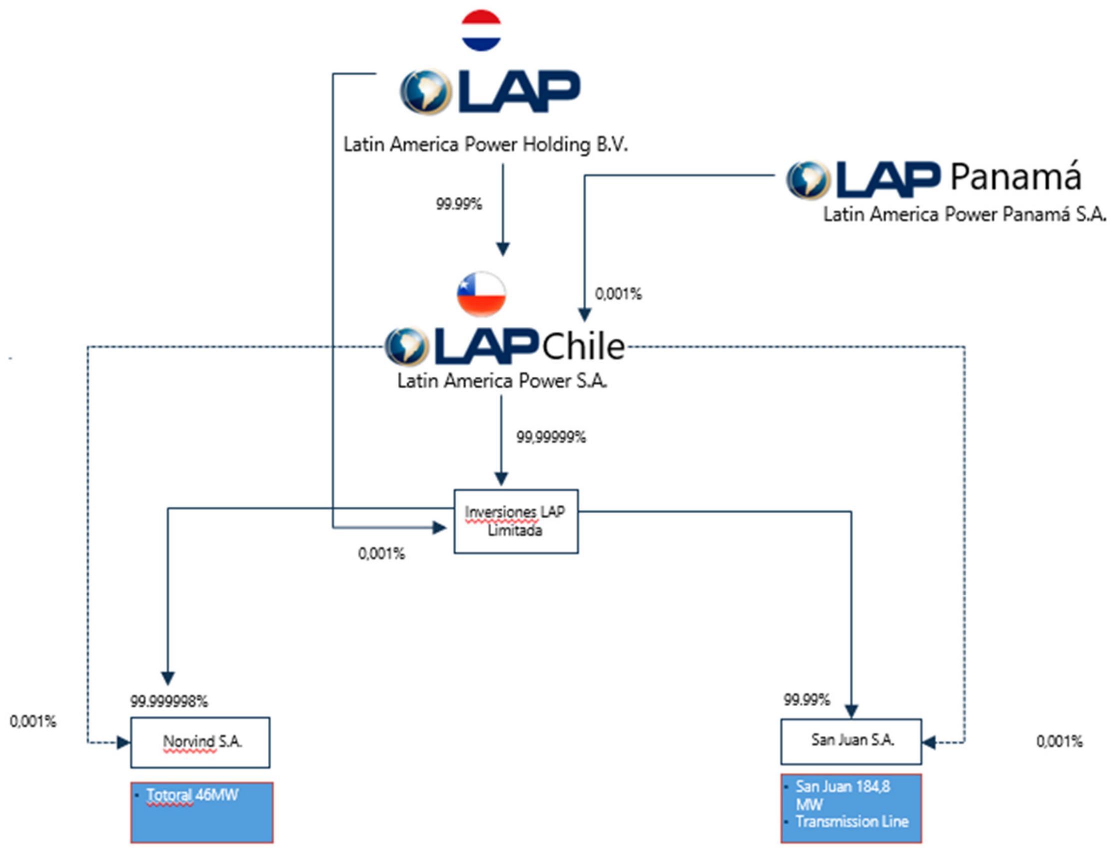
Francisca Perez. Ms. Perez is the Senior Legal Counsel of LAP Chile. Ms. Perez received her law degree from Universidad Diego Portales. She has experience in corporate law, mergers, acquisitions and financing. Prior to joining LAP Chile, she was a member of the team at Baraona Fischer y Cía, a prestigious Chilean law firm, specializing in tax and corporate matters, and was a lawyer for the office of the General Counsel at Farmacias Ahumada S.A., a member of the Walgreens Boots Alliance.

OUR PRINCIPAL SHAREHOLDERS

ILAP is a limited liability company (*sociedad de responsabilidad limitada*) organized under the laws of Chile. ILAP owns all but one share of San Juan and Norvind, while LAP Chile owns the remaining share for each project.

ILAP is 99.9999% owned by LAP Chile and 0.00001% by LAP. LAP owns all but one share of LAP Chile, while LAP Panama owns the remaining share.

Set forth below is the corporate structure chart for the relevant entities:



LAP is a power generation company created with the goal of improving the energy matrix for Chile, Panama and Peru through the development of renewable energy sources, while also maintaining close relationships with neighboring communities and protecting the environment. LAP identifies, develops, builds and operates hydro and wind projects. LAP currently owns a total of 10 projects with an aggregate capacity of approximately 342MW.

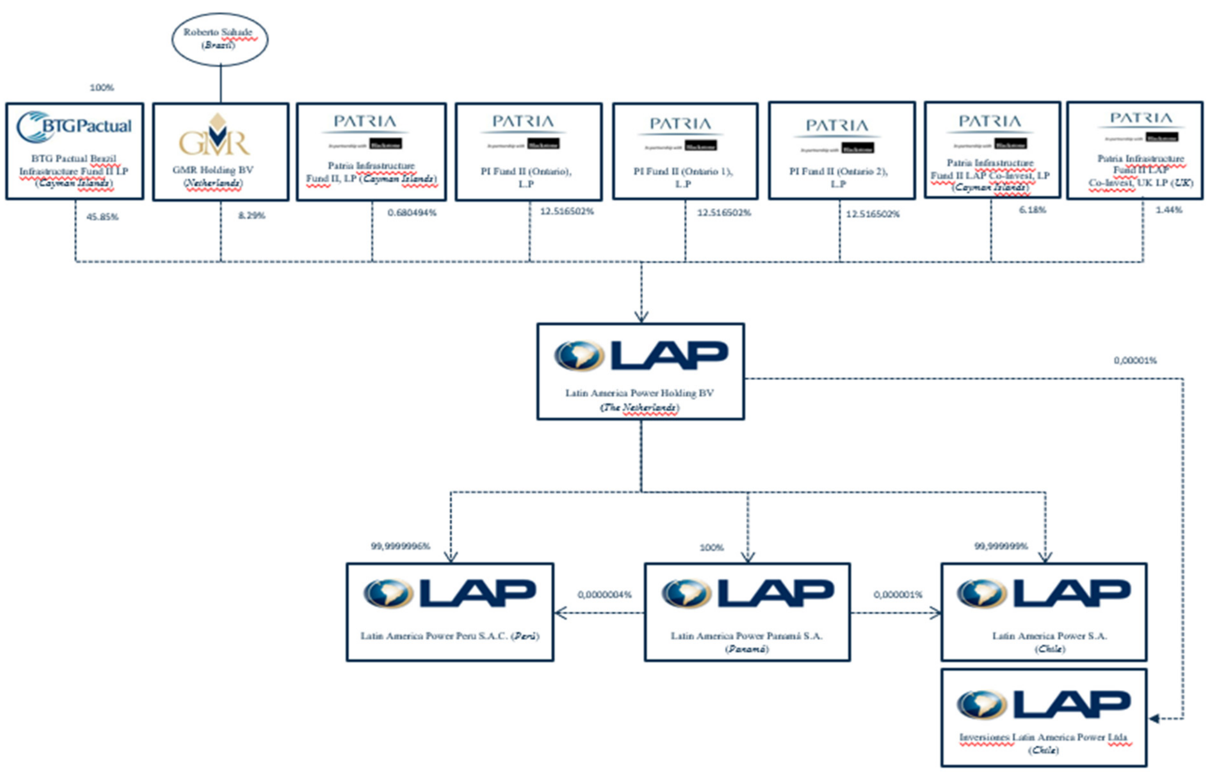
Our ultimate beneficial owners are:

- ***BTG Pactual Brazil Infrastructure Fund II (45.85%)*** is managed by BTG Pactual Brazil, the leading investment bank in Latin America. It holds approximately US$58 billion in assets under management. BTG Pactual Brazil has an extensive track record in investing in the electrical power through the administration of funds. BTG Pactual Brazil has invested in projects which generate more than 3,500 MW. It was a pioneer in wind power investment in Brazil, through Bons Ventos Park (155 MW). Currently holds a participation in renewables assets, thermal plants and transmission lines. In addition, is a leading financial group with operations in energy trading in Brazil.

- **Patria Investments (Patria),** which manages the Patria Funds mentioned above, is one of the most traditional alternative investment firms in Latin America. Patria began its infrastructure investment practice in 2006 by raising a dedicated fund to support ERSA's investment of renewable assets in Brazil. Patria is a pioneer in private equity investments in the region, with over 30 years of experience. The firm currently has over US$ 14.4 billion of assets under management, in funds dedicated to Private Equity, Infrastructure, Real Estate, Public Equities, Agribusiness and Credit Solutions. Patria's infrastructure group, which currently manages US$ 4.7 billion in assets, has significant experience investing in energy. Prior to LAP, Patria co-founded ERSA, a leading player in renewables in Brazil, alongside GMR Energía. Patria currently holds interests in CPFL Renovaveis, the largest renewable energy company in Latin America, with a diversified portfolio of hydro, wind, solar and biomass assets. As of December 2020, Patria's Infrastructure Group held interests in 14 companies, including LAP. Patria also entered into a strategic partnership with the United States' based Blackstone Group in 2010, one of the world's leading alternative asset managers. Since then, Patria's infrastructure practice has raised two other infrastructure funds and has invested in over 12 companies with approximately $3.8 billion in AUM.

- ***GMR Holding B.V. - (8.30%).*** GMR Holding is a Dutch company affiliate of PWR Capital group and holds its investments in Renewable Energy in Latin America. GMR Holding focuses on the energy, forestry and construction/real estate sectors. The company participates in generation businesses within Latin America via its subsidiary GMR. GMR has been operating in the Brazilian energy sector since 2004 and the Chilean and Peruvian energy sectors through investments in LAP since 2011. In 2006, GMR also co-founded ERSA alongside Patria, which later merged with CPFL Energia in 2011 to form.

Set forth below is the corporate structure chart of our ultimate beneficial owners:



RELATED PARTY TRANSACTIONS

In the ordinary course of business, we engage in a variety of transactions with certain of our affiliates, primarily for the purchase, at fair market prices negotiated on an arm's-length basis, of goods or services that may also be provided by other suppliers. See Note 15 to our Audited Consolidated Financial Statements included in this offering memorandum for further description of our related party transactions.

Below is a summary of accounts receivable and accounts payable with related parties, as disclosed in our Unaudited Consolidated Financial Statements for the three months ended March 31, 2021 and 2020, and our Audited Consolidated Financial Statements as of December 31, 2020, 2019 and 2018:

	Three months ended March 31,		Year ended December 31,		
	2021	2020	2020	2019	2018
			(US$ thousands)		
Accounts Receivable					
Latin America Power S.A.	2	2	2	2	-
Empresa Eléctrica Carén S.A.	3,726	3,222	3,834	3,641	-
Total Accounts Receivable	**3,728**	**3,224**	**3,836**	**3,643**	**-**
Accounts Payable					
Latin America Power S.A.	1,735	1,445	1,748	1,570	1,049
LAP Holding B.V.	3,154	3,154	3,154	3,154	3,154
Transmisora Valle Allipén S.A.	-	-	-	-	40
Total Accounts Payable	**4,889**	**4,599**	**4,902**	**4,724**	**4,243**

The debt with LAP Holding B.V. relates to expenses incurred on behalf of ILAP in connection with the NPA in 2017. The debt with LAP Chile relates to financial contributions made to ILAP to support the operation and financing for development and acquisition of new projects. This debt does not bear interest. As of this date, there are no warranties associated with related party balances or allowances for doubtful accounts.

Service Agreements

The table below provides a summary of the services agreement between San Juan and LAP Chile, in connection with general management, back office and administrative services.

	Agreement for the Provision of Services
Agreement	Agreement for the Provision of Services dated April 29, 2015 between San Juan S.A. and Latin America Power S.A., as amended on October 4, 2016.
Term	Eighteen (18) years.
Scope	The scope of work under the Agreement is for the provision of services pertaining to the operation and maintenance of the San Juan Project and its respective transmission system. The services shall generally include the following areas: legal, human resources, internal control, finance and budgets, purchasing and supplying, accounting, computer and information technology, marketing, and project evaluation.

Price	Monthly amount of US$54,395, which will be adjusted annually in January of each year pursuant to a formula set forth in the Agreement.
Availability	The Agreement provides for penalties or credits pursuant to the availability of the substations and the transmission lines, as affected by the services rendered thereunder. To the extent that for any calendar year it is established that the levels of availability of the substations and transmission lines were less than 97%, a penalty shall be imposed in the amount of 3% of the annual price of the Agreement for each 1% of unavailability. Any such fine shall be limited to 15% of the annual price of the Agreement. Alternatively, to the extent that for any calendar year it is established that the levels of availability of the substations and transmission lines were above 97%, a credit shall be imposed in the amount of 1% of the annual price of the Agreement for each 1% of availability above 95%. Any such credit shall be limited to 5% of the annual price of the Agreement. The availability shall be determined pursuant to a formula set forth in the Agreement.
Early Termination	The Agreement may terminate in advance (i) in case either party thereto is declared insolvent or bankrupt or if is subjected to any process of reorganization or liquidation pursuant to the provisions of Law 20,720, or (ii) in the event either party provides ninety (90) days prior written notice to the other party.
Liability Limitations	Neither party shall be liable for any damage, loss, claim or costs arising from the provision of the services described therein, including but not limited to those which may be caused by personnel employed by a party thereto, in the event that such exceed the total amount of US$625,733 annually. The limitation of liability shall not apply with respect to gross negligence, willful misconduct, breaches of labor or social security laws, and breaches of intellectual and industrial property rights and laws.
Assignment	The Agreement may not be assigned by either party without prior written consent of the other party, which consent may not be unreasonably withheld. Notwithstanding the foregoing, the services described therein may be subcontracted in full or in part, provided that the subcontracting party shall remain responsible for the subcontracted services.

DESCRIPTION OF THE NOTES

General

We will issue the Notes (the "*Notes*") guaranteed by San Juan S.A. ("*San Juan*") and Norvind S.A. ("*Norvind*", and together with San Juan, collectively, the "*Guarantors*" and such guarantees, collectively, the "*Note Guarantees*"), under an indenture (the "*Indenture*"), to be dated as of the Issue Date, among us, the Guarantors and Citibank, N.A., as Trustee (in such capacity, the "*Trustee*"), as collateral agent (in such capacity, the "*Offshore Collateral Agent*"), as registrar (in such capacity, the "*Registrar*"), as paying agent (in such capacity, the "*Paying Agent*") and as transfer agent (in such capacity, the "*Transfer Agent*"), and Banco de Chile, as onshore collateral agent (in such capacity the "*Onshore Collateral Agent*"), in a private transaction that is not subject to the registration requirements of the Securities Act. See "*Transfer Restrictions.*"

The Security Documents referred to below under the caption "*—Collateral*" will define the terms of the agreements that will provide for the collateral securing the Notes. The following description is a summary of the material provisions of the Notes, the Indenture and the Security Documents to be entered into on the Issue Date. It does not restate the Notes, the Indenture and such Security Documents in their entirety, and is subject to, and qualified in its entirety by reference to, all of the provisions of the Notes, the Indenture and such Security Documents, in each case, including the definitions therein. Copies of the Notes, the Indenture and such Security Documents are available for inspection at the corporate trust office of the Trustee. We urge you to read the Notes, the Indenture and such Security Documents because they, and not this description, define your rights as a holder of the Notes ("*noteholder*"). Certain terms that are given special meanings in the Indenture are used as defined under the sub-heading "*—Certain Definitions.*" As used in this description, the word "*we*" refers only to Inversiones Latin America Power Limitada (the "*Issuer*") and not to any other entity or Person.

Principal, Maturity and Interest

The Notes will be issued in one series in the aggregate principal amount of US$403,900,000 and will mature on June 15, 2033.

The Notes will bear interest at an annual rate of 5.125% from the Issue Date. We will pay interest on the Notes semi-annually in arrears on each January 3 and July 3, commencing on January 3, 2022 (each, a "*Note Payment Date*"), to the registered noteholders on the second day preceding the applicable Note Payment Date. Interest on the Notes will accrue from the most recent date to which interest has been paid or, if no interest has been paid, from the date of issuance of such Notes (including any Additional Notes, as described herein). Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months. The Issuer or the Guarantors will not be obligated to pay interest (including post-petition interest in any bankruptcy, reorganization or similar proceeding under Applicable Law) on overdue payments on the Notes.

The principal of the Notes is payable in semi-annual installments on each Note Payment Date. The following table is an indicative amortization table for illustration purposes only. Actual amortization payments and scheduled payment dates may be different from those set out below. See "*Certain Assumptions*" in this offering memorandum.

Scheduled Payment Dates	Scheduled Principal Amount (thousands of US$)
03 January, 2022	3,546.00
03 July, 2022	4,754.00
03 January, 2023	4,370.00
03 July, 2023	3,417.00
03 January, 2024	6,127.00
03 July, 2024	4,339.00
03 January, 2025	7,100.00

03 July, 2025	7,632.00
03 January, 2026	10,659.00
03 July, 2026	9,022.00
03 January, 2027	12,228.00
03 July, 2027	10,815.00
03 January, 2028	13,347.00
03 July, 2028	12,263.00
03 January, 2029	14,736.00
03 July, 2029	12,661.00
03 January, 2030	14,037.00
03 July, 2030	13,828.00
03 January, 2031	15,177.00
03 July, 2031	14,735.00
03 January, 2032	16,274.00
03 July, 2032	12,173.00
03 January, 2033	12,996.00
15 June, 2033	167,664.00

Issuance of Additional Notes

We may issue additional Notes under the Indenture, which we refer to as the "*Additional Notes*," in accordance with certain limited conditions described therein *provided*, *however*, that unless such Additional Notes are fungible with the existing Notes for U.S. federal income tax purposes, such Additional Notes shall be issued with a separate CUSIP or ISIN number, as applicable. Any Additional Notes will rank equivalent in right of payment and with respect to rights in the Collateral to the Notes and will vote on all matters with the Notes. For purposes of this "*Description of the Notes*," references to the Notes do not include Additional Notes unless otherwise indicated. No offering of any Additional Notes is being or will in any manner be deemed to be made by this offering memorandum. For a description of the conditions under which we may issue Additional Notes, see "*—Certain Covenants—Limitation on Indebtedness.*"

LC Facility Agreement

The Issuer, as borrower, will enter into a Letter of Credit Facility Agreement on, before or after the Issue Date (the "*LC Facility Agreement*") with Citibank, N.A., as administrative agent for the lenders and issuing lenders (the "*Administrative Agent*"), and Citibank, N.A., as lender (the "*Lender*"), and Citibank, N.A., as issuing lender (the "*Issuing Lender*"), for purposes of issuing one or more standby letters of credit (each, a "*Letter of Credit*") to fund, as permitted under the terms of the Notes, the relevant Collateral Accounts as described in further detail below.

As required under the terms of the Notes, the Issuing Lender shall be a United States bank or financial institution with a rating of at least A- or the equivalent thereof by S&P or Fitch or at least A3 or the equivalent thereof by Moody's (an "*Acceptable Issuer*"). We expect that the maximum exposure of the Letters of Credits issued under the LC Facility Agreement will be up to US$21,000,000. Any and all proceeds from any drawing under the Letters of Credit will be deposited by the Offshore Collateral Agent in the Debt Service Reserve Account or the O&M Reserve Account, in each case, pursuant to the terms of the Security and Depositary Agreement.

The Issuer's obligations under the LC Facility Agreement will be secured ratably by the Collateral Agents and jointly and severally guaranteed by the Guarantors. The Administrative Agent under the LC Facility Agreement will join the Security and Depositary Agreement as a party on behalf of itself, the Lender and Issuing Lender. The payment of the obligations under the LC Facility Agreement would be made pursuant to the accounts waterfall (see "*—Accounts and Priority of Payments*") and, following an enforcement action involving the sale, disposition or other realization, collection or recovery of any amounts or any Collateral, the Issuer's obligations under the LC Facility Agreement would rank *pari passu* with the Notes. The Issuer will also establish a cash collateral account at the Offshore Depositary Bank into which the Issuer may be required to deposit, or cause the deposit of, cash collateral in respect of issued and undrawn Letters of Credit in certain circumstances upon the occurrence of an event of default as provided in the LC Facility Agreement and the Security and Depositary Agreement.

Under the Security and Depositary Agreement, to the extent that the Debt Service Reserve Account or the O&M Reserve Account is being funded by a Reserve Letter of Credit, the Offshore Collateral Agent will draw on the applicable Reserve Letter of Credit as provided in "*—Accounts and Priority of Payments*."

If, (a) with respect to any Reserve Letter of Credit issued to fund the Debt Service Reserve Account, amounts on deposit in the Payment Account are, on the date that is four (4) Business Days prior to the next succeeding applicable payment date, insufficient to make payments under the Indenture or (b) with respect to any Reserve Letter of Credit issued to fund the O&M Reserve Account, if amounts held in the Operations Accounts are, on the date that is four (4) Business Days prior to the next succeeding applicable payment date, insufficient to pay O&M Costs, in each case, such Reserve Letter of Credit may be drawn to pay such deficiency in accordance with the Security and Depositary Agreement and as further described in "*—Accounts and Priority of Payments*".

Intercreditor Arrangements

The Security and Depositary Agreement will govern the rights of the Secured Parties with respect to the Collateral and will provide for the *pari passu* treatment of the Secured Parties and set forth other relative rights among (i) the holders of the Notes, represented by the Trustee, and (ii) the Lender and Issuing Lender, represented by the Administrative Agent (the "*Letter of Credit Secured Parties*"). If the Issuer or the Guarantors incur any additional Indebtedness that is permitted to be secured on a *pari passu* basis with the Notes, then the provider of such additional Indebtedness (or its appointed representative) will accede to the Security and Depositary Agreement. An intercreditor agent (the "*Intercreditor Agent*") will be appointed under the Security and Depositary Agreement for the purposes of tabulating any Intercreditor Votes and coordinating among the classes of Secured Parties.

Pari Passu Benefits

The obligations of the Issuer and the Guarantors owed to the Letter of Credit Secured Parties (the "*LCF Obligations*") and the noteholders will at all times rank at least *pari passu* in right of payment and security with any other present and future senior debt of the Issuer and the Guarantors. The Collateral will secure all the Notes and the LCF Obligations on a *pari passu* basis among themselves.

Priority of Payments

Following an enforcement action involving the sale, disposition or other realization, collection or recovery of any amounts or any Collateral (or any portion thereof) (all proceeds of any sale, collection or other liquidation of any Collateral and all proceeds of any such distribution being collectively referred to as "*Collateral Proceeds*"), the Collateral Proceeds will be transferred by the applicable Collateral Agent as provided below (except that all Collateral Proceeds attributable to any Debt Service Reserve Account shall be transferred to the Trustee, *first* for the pro rata payment of all accrued and unpaid interest (including default interest, if any) on the Senior Secured Obligations under the Indenture and, *second*, if any unpaid principal or premium (if applicable) of such Senior Secured Obligations under the Indenture has become due (by acceleration or otherwise), to the payment of such unpaid principal and premium). Following the application of the amounts described in the parenthetical of the immediately preceding sentence, the Collateral Agent will apply all other Collateral Proceeds toward the payment of the Senior Secured Obligations in the following order of priority:

(i) *first*, (A) *first*, to the payment of the fees, indemnities, costs (including administrative costs owed to the Trustee, Administrative Agent or any other agent, representative, receiver or delegate) and expenses then due and payable to the Trustee, the Administrative Agent, the other agents or representatives in respect of any Senior Secured Obligations and then (B) *second*, to the payment of the fees (other than fees payable pursuant to clause (ii) below), indemnities, costs and expenses then due and payable to the other Secured Parties in respect of any Senior Secured Obligations;

(ii) *second*, to the payment of any (A) accrued and unpaid interest, premium and breakage costs (including post-petition interest, whether or not an allowed claim in any Insolvency Proceeding) in respect of any Senior Secured Obligations and (B) accrued and unpaid commitment fees, Reserve Letter of Credit fees and participation or other fees in respect of any Senior Secured Obligations (other than amounts paid under clause (i) above);

(iii) *third*, *pro rata,* to the payment of any outstanding principal amount then due and payable in respect of any Senior Secured Obligations (including reimbursement obligations under any Reserve Letter of Credit, Loans under the LC Facility Agreement and cash collateralization of all outstanding Letters of Credit (if any) constituting Senior Secured Obligations);

(iv) *fourth*, to the payment of any other outstanding Senior Secured Obligations under any secured document subject to the Security and Depositary Agreement (the "*Secured Documents*"); and

(v) *fifth*, the balance, if any, after all Senior Secured Obligations have been paid in full in cash, to the Issuer and the other Guarantors or their successors or permitted assigns, as their interests may appear, or to whosoever may be lawfully entitled to receive the same, or as a court of competent jurisdiction may direct.

Any amounts owed to a Secured Party must be transferred to and applied by such Secured Party's representative in accordance with the Security and Depositary Agreement.

Shared Collateral

The Security and Depositary Agreement provides that the Secured Parties will share ratably in the Collateral in which the Collateral Agents hold, on behalf of the Secured Parties, a valid and perfected security interest at such time, except for the Debt Service Reserve Account which is for the benefit solely of the noteholders and the Letter of Credit Account and related cash collateral is for the benefit solely of the Letter of Credit Secured Parties (the "*Shared Collateral*").

Each Secured Party has agreed that it will not accept any Lien on any Collateral for the benefit of any Senior Secured Obligations other than pursuant to the Security Documents and, by executing the Security and Depositary Agreement, each of the Secured Parties has agreed that it will not question or contest or support any other Person in contesting, in any proceeding, the perfection, priority, validity, attachment or enforceability of a Lien held by or on behalf of any of the Secured Parties in all or any part of the Collateral.

Each Secured Party has agreed that, if it obtains possession of any Shared Collateral or realizes any proceeds or payment in respect of any such Shared Collateral for any reason other than as permitted to be retained by such Secured Party pursuant to the terms of the Security and Depositary Agreement, at any time prior to the discharge of the Senior Secured Obligations, then it will hold such Shared Collateral, proceeds or payment in trust for the other Secured Parties.

Voting

Except as otherwise expressly provided in the Security and Depositary Agreement, each noteholder and lender required to authorize such direction under the Security and Depositary Agreement (the "*Voting Secured Parties*") shall be entitled to vote (through its authorized representative) in each vote conducted under the Security and Depositary Agreement (an "*Intercreditor Vote*"). Each decision of the noteholders and lenders required to authorize any such direction under the Security and Depositary Agreement (the "*Required Secured Parties*") made in accordance with the terms of the Security and Depositary Agreement shall be binding upon each of the Secured Parties.

Each Secured Party that is a party to the Security and Depositary Agreement (for itself, each Secured Party on whose behalf it executes the Security and Depositary Agreement and any other Person claiming through it) will agree under the Security and Depositary Agreement that no Secured Party shall, except in accordance with the provisions of the Security and Depositary Agreement, take any enforcement action except in accordance with the provisions of the Security and Depositary Agreement (it being agreed that no acceleration in respect of a Senior Secured Obligation, event of default or termination or suspension of a commitment under the Secured Documents shall be deemed to be an enforcement action for any purposes of the Security and Depositary Agreement).

Each Voting Secured Party (through its authorized representative) will have a number of votes in any Intercreditor Vote equal to the portion (in U.S. dollar amounts in relation to the aggregate U.S. dollar amount of the combined exposure) of the combined exposure represented by the Senior Secured Obligations owed to it under its respective Secured Documents.

In calculating the voting party percentage consenting to, approving, waiving or otherwise providing direction with respect to any decision, the total number of votes cast by all Voting Secured Parties in favor of the proposed decision (the "*Numerator*") shall be divided by the total number of votes entitled to be cast with respect to such matter (the "*Denominator*"). The voting party percentage shall not include any votes excluded.

If, within forty-five (45) Business Days or a longer period prescribed by the Collateral Agents (acting at the written direction of the Required Secured Parties) not to exceed one hundred and twenty (120) days) (the "*Decision Period*"), the required voting party percentage is reached then such proposed decision is approved and no Secured Party may object to any of the terms or provisions contained in the Intercreditor Vote. If, within the Decision Period, a Voting Secured Party does not respond approving or disapproving the relevant Intercreditor Vote, then the number of votes of such Voting Secured Party in such Intercreditor Vote shall not be included as part of the Numerator or Denominator in calculation such Intercreditor Vote; provided that in cases where DTC's Automated Tender Offer Program ("*ATOP*") procedures are utilized, any outstanding Indebtedness under any Secured Documents constituting a bond or similar security (including the holders in respect of the Notes) that does not vote affirmatively shall not be excluded from both the Numerator and Denominator of the calculation. In all cases in which the Trustee is required to notify noteholders of any Intercreditor Vote (including any solicitation to such noteholders to approve or disapprove a relevant Intercreditor Vote) the Trustee may structure the notice to Holders so that such notice or solicitation is eligible in accordance with the applicable procedures at DTC that the Trustee determines to facilitate such vote, including causing such notice to be processed through DTC's ATOP, which among other things may only allow holders to provide an affirmative vote.

The Indenture will address the manner in which noteholders may instruct the Trustee to vote on their behalf in connection with Intercreditor Votes, including in respect of the provision of instructions or votes to the Trustee through the systems of DTC. The Trustee will have no responsibility or liability for the terms or requirements of any such systems or procedures offered by DTC, or any unavailability thereof.

Defaults and Remedies

If an event of default under the Indenture or the LC Facility Agreement occurs and is continuing, the Required Secured Parties may instruct the Trustee and the Administrative Agent to direct the applicable Collateral Agent to take any or all of the actions listed below (irrespective of their order, each a "*Remedies Instruction*"), instituting judicial or extra-judicial proceedings to protect and enforce the rights vested in any of the Secured Parties by the Secured Documents (including bringing appropriate judicial proceedings or taking any of the actions as shall be provided for in the Security Documents), and each Collateral Agent, as directed by the Intercreditor Agent, shall be permitted to (i) liquidate and make Permitted Investments in, in the case of the Offshore Collateral Agent, the Offshore Accounts, and in the case of the Onshore Collateral Agent, the Onshore Accounts, (ii) direct the disposition of the funds in, in the case of the Offshore Collateral Agent, each of the Offshore Accounts, and in the case of the Onshore Collateral Agent, each of the Onshore Accounts, (iii) transfer amounts from the Revenue Accounts or the O&M Reserve Account to the Operations Accounts to pay O&M Costs then due and payable, (iv) pay interest and principal and all other obligations then due and payable under the Secured Documents in accordance with the priorities established in the Security and Depositary Agreement, (v) to the extent permitted by Applicable Law, use any Collateral to repay the Senior Secured Obligations and (vi) initiate appropriate proceedings to sell, dispose or realize on the Collateral, in each case, if and as so directed by any Remedies Instruction received by such Collateral Agent, all in accordance with the Security and Depositary Agreement and the applicable Security Documents.

Unless otherwise consented to in writing by the applicable Collateral Agent (pursuant to the written instructions of the Trustee and the Administrative Agent, in each case acting at the written direction of the applicable Required Secured Parties under the Indenture and the LC Facility Agreement, respectively), no Secured Party, individually or together with any other Secured Party, has the right, nor will it (x) exercise or enforce any of the rights, powers or remedies that the Collateral Agents are authorized to exercise or enforce under the Security and Depositary Agreement or any other Security Document with respect to the Shared Collateral or (y) take any step for the winding-up, administration of or dissolution of, or any Insolvency Proceeding in relation to, the Issuer and the Guarantors or any of the Guarantors, or for a voluntary arrangement, scheme of arrangement or other analogous step in relation to the Issuer and the Guarantors or any of the Guarantors. However, any Secured Party may:

(i) file a claim or statement of interest with respect to the Senior Secured Obligations owed to such Person so long as a liquidation or Insolvency Proceeding has been commenced by or against the Issuer and the Guarantors or any of the Guarantors;

(ii) file any necessary or appropriate responsive or defensive pleadings in opposition to any motion, claim, adversary proceeding or other pleading made by any person objecting to or otherwise seeking the disallowance of the claims or Liens of the Collateral Agents or any other Secured Party, including any claims secured by the Shared Collateral; and

(iii) file any pleadings, objections, motions or agreements that assert rights or interests available to unsecured creditors of the Issuer and the Guarantors or any of the Guarantors arising under any liquidation or Insolvency Proceeding of the Issuer and the Guarantors or any of the Guarantors or applicable non-bankruptcy law, or exercise any other rights and remedies that could be exercised by an unsecured creditor against the Issuer and the Guarantors or any of the Guarantors.

Release of Liens

Each authorized representative of holders of Senior Secured Obligations has authorized the applicable Collateral Agent to execute and deliver to the Issuer and the Guarantors any instrument (including a modification to any Security Document) and to perform all acts and provide all instructions and notices reasonably required for such purposes as the Issuer and the Guarantors shall reasonably request to evidence (i) the release of any Lien on any Shared Collateral granted to or held by a Collateral Agent under any Security Document (including termination of a Project Document, either by virtue of the scheduled expiration in the ordinary course in accordance with its terms or as permitted under the Indenture Documents, sale of Property as permitted under the Indenture Documents, or sale, cancellation or exchange of Equity Interests in the Issuer or the Guarantors as permitted by the Indenture Documents), or (ii) the release of any Guarantor or Guarantors from its obligations under any Secured Document, subject to, in each such case, (A) the release of such Lien of the Issuer and the Guarantors or any of the Guarantors being permitted by the terms of each then-extant Secured Document subject to all conditions to such release under each then-extant Security Document having been satisfied and (B) the applicable Collateral Agent having received a certificate from a Responsible Officer of the Issuer and the Guarantors, at least five (5) Business Days prior to the proposed date of the release, certifying to clause (A) above and specifying the relevant provision(s) in each such Secured Document permitting such release, and attaching the proposed instrument for execution.

Waivers and Amendments

Modifications with respect to the provisions of any Secured Document (other than the Security and Depositary Agreement and the other Security Documents) shall be made in accordance with the requirements of each such separate Secured Document. Notwithstanding any provision to the contrary in the Security and Depositary Agreement, the requisite number of Voting Secured Parties specified in any particular Secured Document may at any time after the occurrence and during the continuance of an event of default under such Secured Document accelerate the Senior Secured Obligations thereunder in accordance with the terms thereof.

The Collateral Agents may not enter into any consent, waiver, amendment, modification or supplement to any Security Document other than pursuant to a decision of the Required Secured Parties, unless such consent, waiver, amendment, modification or supplement (a) is in accordance with the Security Documents and (b) does not adversely affect the rights of the Secured Parties; provided, however, that, without the consent of any Secured Party (other than a Collateral Agent, if required pursuant to the Security and Depositary Agreement) or any other Person, any provision of the Security and Depositary Agreement or any other Security Document may be modified by the applicable Obligor and Collateral Agent to (i) cure any ambiguity, omission, mistake, defect or inconsistency, (ii) subject to the Lien priority and subordination provisions of this Agreement, to (A) make any change that would provide any additional rights or benefits to the Secured Parties or (B) make, complete or confirm any grant of Collateral permitted or required by the Security and Depositary Agreement or any other Security Documents, or any release of any Collateral that is permitted under the terms of the Security and Depositary Agreement and the other Secured Documents and (C) to make administrative or mechanical modifications to provide for the addition of obligations secured by the Collateral or the addition of any Subsidiary as permitted or required (or, if not addressed therein, not prohibited) under the Secured Documents so long as such modifications do not modify the rights and obligations of the parties hereto (other than as may result from having additional secured obligations benefiting from the Collateral and additional secured parties voting as provided herein and having other rights of secured parties under the Security and Depositary Agreement and under the applicable Secured Documents).

The Security and Depositary Agreement may only be terminated, waived, amended or modified in writing by each authorized representative, the Collateral Agents and the Obligors.

Collateral

The Notes will be secured, subject to Permitted Liens (as defined below), by the Security Documents described in (1) to (16) below and the Collateral Accounts described under the caption "*Collateral Accounts*" in this offering memorandum (together, the "*Collateral*"), *pari passu* and *pro rata* among all other Senior Secured Obligations.

A release (*alzamiento*) of all related Liens of the holders of the Existing Indebtedness on the Collateral and all other assets of the Issuer and the Guarantors and of all the security documents and guarantees, including, but not limited to, pledges (*prendas*) of any kind, mortgages (*hipotecas*), conditional assignments (*cesiones condicionales*), collection mandates (*mandatos de cobro*) and subordination agreements (*acuerdos de subordinación*), related to and securing the Existing Indebtedness (the "*Prior Security Documents*") will be duly executed and delivered by the parties thereto on the Issue Date, and the Onshore Collateral Agent will receive satisfactory evidence from local counsel to the Secured Parties or otherwise, that the release of the Prior Security Documents has been duly executed and is in a form that is ready to be filed, registered or recorded as required for the effectiveness of such release.

The Chilean Security Documents (as defined below) will be duly executed and delivered by the parties thereto on the Issue Date, and the Onshore Collateral Agent will receive satisfactory evidence from local counsel to the Secured Parties or otherwise, that such Chilean Security Documents have been duly executed.

The following Chilean law security documents (each a "*Chilean Security Document*") will be granted in favor of the Onshore Collateral Agent, for the benefit of the Secured Parties:

(1) the onshore collateral agency agreement (*contrato de agencia de garantías*), among the Onshore Collateral Agent, the Trustee, the Administrative Agent, the Intercreditor Agent, the Issuer, each of the Guarantors, Latin America Power Holding B.V. and Latin America Power S.A.;

(2) an acknowledgement of debt, granted by the Issuer;

(3) crossed joint and several guarantee (*fianza y codeuda solidaria*), granted by each of the Guarantors;

(4) the first priority commercial pledge (*prenda comercial*) over the electric concessions of San Juan;

(5) each of the first priority pledges without conveyance (*prendas sin desplazamiento de primer grado*) over the rights on the future Material Project Documents of the Issuer and each of the Guarantors other than the Long-Term Power Purchase Agreements entered into with non-distribution companies;

(6) each of the first priority pledges without conveyance (*prendas sin desplazamiento de primer grado*) over the existing and future shares of each of the Guarantors;

(7) each of the first priority commercial pledges (*prendas comerciales*) over the existing Material Project Documents of the Guarantors and promises to grant first priority commercial pledges (*promesas de prendas comerciales*) over the future Material Project Documents (consisting in the Long-Term Power Purchase Agreement entered into with non-distribution companies) of the Issuer and each of the Guarantors;

(8) first priority pledge without conveyance (*prenda sin desplazamiento de primer grado*) over the existing and future equity rights of the Issuer;

(9) each of the first priority pledges without conveyance (*prendas sin desplazamiento de primer grado*) over the amounts deposited in certain Collateral Accounts of the Issuer and each of the Guarantors in Chile and permitted investments thereof;

(10) each of the first priority pledges without conveyance (*prendas sin desplazamiento de primer grado*) over existing and future movable Property of the Issuer and each of the Guarantors;

(11) each of the first priority pledges without conveyance (*prendas sin desplazamiento de primer grado*) over the Issuer's rights on intercompany indebtedness or in future indebtedness acquired by the Issuer against any of the Guarantors;

(12) each of the first priority mortgages (*hipotecas de primer grado*) over existing and future real estate, mining concession and water rights of the Issuer and each of the Guarantors;

(13) the conditional assignment of rights on the Material Project Documents of the Guarantors and promise to grant conditional assignment of rights on the future Material Project Documents (*cesión condicional de derechos y promesa de cesión condicional de derechos*) of the Issuer and each of the Guarantors;

(14) the collection mandate and promise to grant collection mandate (*mandato irrevocable de cobro y promesa de mandato irrevocable de cobro*), over payments under the Material Project Documents, including future Material Project Documents;

(15) the subordination agreements (*acuerdos de subordinación*) of all the credits that the Issuer has or might have against any of the Guarantors, and all the credits that any of the Guarantors has or might have against the Issuer; and

(16) the endorsement (*endoso*) of or designation as beneficiary (*designación de asegurado adicional o beneficiario exclusivo de póliza de seguro*) under all of the insurance policies issued by Chilean companies of each of the Guarantors to the Onshore Collateral Agent.

Collateral Accounts and Priority of Payments

The Collateral Accounts will be established and maintained in accordance with the Security and Depositary Agreement, and such agreement will also provide for the establishment of, deposits into and withdrawals from the applicable Collateral Accounts. The Collateral Accounts will be subject to the Liens of the Collateral Agents pursuant to the Security Documents.

Offshore Accounts

The Offshore Accounts will include the Note Proceeds Account, the Payment Account, the Debt Reserve Account, the Prepayment Account, the O&M Reserve Account, the Distribution Holding Account and the Letter of Credit Account (collectively, the "*Offshore Accounts*"). The Issuer shall establish each of the Offshore Accounts in its name at the Offshore Depositary Bank and shall grant a Lien over each such Offshore Account pursuant to the Security and Depositary Agreement.

Note Proceeds Account

On the Issue Date the proceeds of the Notes will be deposited into a note proceeds account (the "*Note Proceeds Account*").

The Issuer shall cause the funds on deposit in the Note Proceeds Account to be withdrawn and transferred in accordance with the flow of funds memorandum provided on or prior to the Issue Date.

Payment Account

The Issuer shall cause to be funded any amounts from the Revenue Accounts or the Debt Service Reserve Account to be deposited in the Payment Account in accordance with the Security and Depositary Agreement.

Funds on deposit in the Payment Account shall be withdrawn by the Offshore Depositary Bank for the payment of scheduled debt service with respect to Senior Secured Obligations; *provided* that, in each case, payment of all scheduled debt service with respect to Senior Secured Obligations due and payable as of any date will be made on a *pari passu* basis as of such date.

O&M Reserve Account

Amounts will be deposited in the operations and maintenance reserve account (the "*O&M Reserve Account*") (i) on the Issue Date, with cash, one or more Acceptable LCs, or a combination of the foregoing, at the discretion of the Issuer and (ii) from the Revenue Accounts in accordance with the Security and Depositary Agreement. The Issuer will cause the Offshore Depositary Bank to withdraw an amount equal to any deficiency in O&M Costs from the O&M Reserve Account, to the extent of funds then available on deposit therein, and transfer such amounts to the Operations Accounts for the payment of such O&M Costs; *provided* that the Issuer shall only be permitted to withdraw amounts from the O&M Reserve Account to remedy such a deficiency after the Issuer shall have first withdrawn amounts from other Collateral Accounts of a lower priority in the accounts waterfall described in "— *Revenue Accounts*" than the O&M Reserve Account to cure such deficiency. Such amount to be withdrawn from the O&M Reserve Account, if necessary, shall be in an amount that, taken together with the amounts withdrawn from the Revenue Accounts and other Collateral Accounts of a lower priority than the O&M Reserve Account, is sufficient to remedy such deficiency.

If funds on deposit in the O&M Reserve Account are not sufficient to make the requested withdrawal, then the Offshore Depositary Bank shall notify each Obligor, the Trustee, the Administrative Agent and the Offshore Collateral Agent of the shortfall (i.e., such deficiency less amounts available in the O&M Reserve Account).

So long as a Default or Event of Default has not occurred and is continuing, if on any monthly transfer date, to the extent the balance in the O&M Reserve Account (taking into account the undrawn amount then available under any Acceptable LC credited to the O&M Reserve Account) exceeds the then-required O&M Reserve Requirement (the amount of such excess, the "*O&M Reserve Excess*"), the Issuer may reduce any non-cash portion of such O&M Reserve Excess by reducing the face amount of any such Acceptable LC in an aggregate amount up to such O&M Reserve Excess or to reduce any cash portion of such O&M Reserve Excess by directing the Offshore Depositary Bank to transfer such O&M Reserve Excess to the Revenue Accounts.

Debt Service Reserve Account

Amounts will be deposited in the debt service reserve account (the "*Debt Service Reserve Account*") (i) on the Issue Date, with cash, one or more Acceptable LCs, or a combination of the foregoing, at the discretion of the Issuer and (ii) from the Revenue Accounts in accordance with the Security and Depositary Agreement. The Issuer shall cause the Offshore Depositary Bank to withdraw from the Debt Service Reserve Account an amount equal to a deficiency in the amount of scheduled debt service available in the Payment Account (in connection with the payment of obligations under the Notes) to the extent of funds then available on deposit therein and transfer such amounts to the Payment Account for the payment of such Senior Secured Obligations (in connection with the payment of obligations under the Notes); *provided* that the Issuer shall only be permitted to withdraw amounts from the Debt

Service Reserve Account to remedy such a deficiency after the Issuer shall have first withdrawn amounts from other Collateral Accounts of a lower priority in the accounts waterfall described in "*—Revenue Accounts*" than the Debt Service Reserve Account to cure such deficiency. Such amount to be withdrawn from the Debt Service Reserve Account, if necessary, shall be in an amount that taken together with the amounts withdrawn from the Revenue Accounts and other Collateral Accounts of a lower priority than the Debt Service Reserve Account is sufficient to remedy such deficiency.

If funds on deposit in the Debt Service Reserve Account are not sufficient to make the requested withdrawal, then the Offshore Depositary Bank shall notify each Obligor, the Trustee, the Administrative Agent and the Offshore Collateral Agent of the shortfall (i.e., such deficiency less amounts available in the Debt Service Reserve Account).

So long as a Default or Event of Default has not occurred and is continuing, if on any monthly transfer date, to the extent the balance in the Debt Service Reserve Account (taking into account the undrawn amount then available under any Acceptable LC credited to the Debt Service Reserve Account) exceeds the then-required DSRA Requirement (the amount of such excess, the "*Debt Service Reserve Excess*"), the Issuer may reduce any non-cash portion of such Debt Service Reserve Excess by reducing the face amount of any such Acceptable LC in an aggregate amount up to such Debt Service Reserve Excess or to reduce any cash portion of such Debt Service Reserve Excess by directing the Offshore Depositary Bank to transfer such Debt Service Reserve Excess to the Revenue Accounts.

Reserve Letters of Credit

At any time an issuer of any Acceptable LC credited to the Debt Service Reserve Account or the O&M Reserve Account (any such Acceptable LC, a "*Reserve Letter of Credit*") fails to satisfy the requirements of the definition of Acceptable Issuer, the Issuer shall notify the Offshore Collateral Agent of the occurrence of such event and shall, within ten Business Days from the date on which such issuer failed to satisfy the requirements of the definition of Acceptable Issuer, cause cash to be contributed or furnish substitute Acceptable LC having an aggregate stated amount equal to an amount necessary to cause the Debt Service Reserve Account or the O&M Reserve Account, as applicable, to have an amount on deposit (together with cash and/or other existing Acceptable LC credited to each such Collateral Account), equal to the DSRA Requirement or the O&M Reserve Requirement, as applicable. If the Issuer fails to deliver to the Offshore Collateral Agent substitute Acceptable LC prior to the expiration of such ten Business Day period, then, the Offshore Collateral Agent shall draw upon such Reserve Letter of Credit and shall deposit the proceeds of any such drawing into the Debt Service Reserve Account or the O&M Reserve Account to which such Reserve Letter of Credit, as applicable, was credited. The Offshore Collateral Agent shall not be deemed to have notice that any Person that has issued an Acceptable LC has ceased to be an Acceptable Issuer until it has received written notice from the Issuer as described above and shall have no liability for any failure or delay in making any draw as a result of any failure or delay in receiving the notice described above.

At any time the Issuer may deliver (or cause to be delivered) to the Offshore Collateral Agent a substitute Acceptable LC in substitution for the existing Reserve Letter of Credit credited to the Debt Service Reserve Account or O&M Reserve Account, as applicable, having a stated amount necessary to cause the applicable Collateral Account to have an amount on deposit (together with cash and Acceptable LC credited to such Collateral Account and not being substituted), equal to the DSRA Requirement or the O&M Reserve Requirement, as applicable. Upon the Offshore Collateral Agent's receipt of (A) such substitute Acceptable LC and (B) a certificate of a Responsible Officer of the Issuer that such substitute Acceptable LC so delivered to the Offshore Collateral Agent meets the conditions of the Security and Depositary Agreement (including as to form of Letter of Credit and amount) in order to constitute an Acceptable LC, the Offshore Collateral Agent must return the Acceptable LC being replaced to the issuer or issuers thereof, together with any certificate or other documentation that may be reasonably required to effect the cancellation of such Acceptable LC.

If, at any time, any Acceptable LC credited to the Debt Service Reserve Account or the O&M Reserve Account is not renewed or extended in accordance with its terms and such Acceptable LC is not otherwise replaced with substitute Acceptable LC or cash in accordance with this Agreement at least thirty (30) days prior to its scheduled expiration, then, the Offshore Collateral Agent is hereby directed to and shall draw upon such Reserve Letter of Credit in full prior to such expiration or termination date and shall deposit the proceeds of any such drawing into the Debt Service Reserve Account or the O&M Reserve Account, as applicable. In connection with making any draw under the Acceptable LC, the Offshore Collateral Agent shall have no liability for making any such draw when acting in good faith.

Prepayment Account

Amounts will be deposited in the Prepayment Account from the Loss Proceeds Accounts and Revenue Accounts in accordance with the Security and Depositary Agreement. The Issuer shall cause the Offshore Depositary Bank to make withdrawals and transfers of amounts in the Prepayment Account in the order set forth in priorities *sixth* through *ninth* (inclusive) in the accounts waterfall described in section "—*Revenue Accounts*."

Distribution Holding Account

The distribution holding account (the "*Distribution Holding Account*") shall be funded from amounts transferred from the Revenue Accounts in accordance with the Security and Depositary Agreement. The Issuer shall cause the Offshore Depositary Bank to make withdrawals and transfers of amounts in the Distribution Holding Account, subject to the satisfaction of the Distribution Release Conditions described in "—*Restricted Payments*" to the Distribution Account.

Letter of Credit Account and Cash Collateral

If an event of default shall occur and be continuing under the LC Facility Agreement and the Issuing Lender or required Lenders under the LC Facility Agreement so require, automatically upon any bankruptcy event of default, or if any Letters of Credit are required to be cash collateralized as a result of a Change of Control or repayment in full of the Notes, in each case, the Issuer shall cause, on each monthly transfer date thereafter, an amount in cash equal to the funds (if any) available to be transferred to the Letter of Credit Account as set forth in priority *seventh* of the Revenue Accounts waterfall described below, when taken together with all previous amounts deposited into the Letter of Credit Account equal to 102.5% of the aggregate undrawn amount available to be drawn on all issued and outstanding Letters of Credit as of such date. Upon the taking of an enforcement action pursuant to the Security and Depositary Agreement, the Borrower shall deposit into the Letter of Credit Account an amount in cash equal to 102.5% of the aggregate. Any deposit made to cash collateralize any Letter of Credit shall be held by the Offshore Collateral Agent as collateral for the Letter of Credit Secured Parties and shall, in the case of a Letter of Credit Disbursement in respect of any Letter of Credit, be applied to the payment of the Borrower's obligations in respect of such Letter of Credit reimbursement obligations and in respect of any loans under the LC Facility Agreement resulting from any drawing on a Letter of Credit and in both cases accrued interest thereon.

Onshore Accounts

The USD Revenue Accounts and Peso Revenue Accounts (collectively, the "*Revenue Accounts*"), the USD Loss Proceeds Accounts and the Peso Loss Proceeds Accounts (collectively, the "*Loss Proceeds Accounts*") and the USD Operations Accounts and the Peso Operations Accounts (collectively, the "*Operations Accounts*" and, together with the Revenue Accounts and the Loss Proceeds Accounts, the "*Onshore Accounts*") will be established pursuant to the Security and Depositary Agreement. The Issuer and each Guarantor shall establish each of the Onshore Accounts, each in its own name, at the Onshore Depositary Bank and shall grant a Lien over each such Onshore Account pursuant to the applicable Security Documents.

The Obligors may also establish unrestricted accounts (collectively, the "*Unrestricted Accounts*") into which the Obligors can deposit proceeds from Permitted Equity Issuances and Permitted Subordinated Indebtedness and which Unrestricted Accounts will not be subject to the Liens under the Security Documents.

Revenue Accounts

The Obligors shall cause each Revenue Account to be funded with (i) all Project Revenues (including PEC Receivables) denominated in the corresponding currency of such Revenue Account and any other amount of the corresponding currency received by such Obligor from time to time, except to the extent such other amounts are expressly required to be funded into another Collateral Account, (ii) funds from the Prepayment Account, (iii) funds from the Loss Proceeds Accounts and (iv) funds from the Unrestricted Accounts or any Distribution Account, each in accordance with the Security and Depositary Agreement.

The Obligors shall cause the amounts on deposit in the Revenue Accounts to be withdrawn and transferred for application as set forth below, in each case, to the extent of available funds:

first, on a monthly basis, to transfer to the applicable Operations Account an aggregate amount equal to (i) the amount needed to pay the aggregate amount of O&M Costs of the Obligors projected to be due and payable in the monthly period beginning on such transfer date in accordance with the then-applicable Annual Budget plus (ii) an additional amount, not to exceed at any time an amount equal to twenty percent (20%) of the amounts being transferred to the Operations Accounts on such date; provided that (A) at no time shall amounts transferred to the Operations Accounts in any fiscal year exceed 110% of the applicable amount in the Annual Budget for such fiscal year without approval of the Independent Engineer and (B) Emergency Costs may be payable on any applicable transfer date to the extent there are not sufficient funds in the Operations Accounts for such costs;

second, on a monthly basis, (A) *first*, to the Trustee, the Intercreditor Agent, the Administrative Agent, the Offshore Collateral Agent, the Onshore Collateral Agent, the Offshore Depositary Bank and the Onshore Depositary Bank, *pro rata*, then (B) to any other Secured Party or other Person entitled thereto, an amount sufficient to pay any and all Senior Secured Obligations comprising the administrative fees, fees under the LC Facility Agreement, costs, charges and expenses and indemnification payments (but excluding any principal amounts of Notes, Loans or interest expense payable on such amounts or similar amounts on additional Indebtedness) then due and payable, or reasonably expected to become due and payable prior to the following monthly transfer date;

third, on a monthly basis, to the Payment Account, in an amount such that the amount on deposit in the Payment Account is equal to a fraction of the scheduled debt service under the Secured Documents which will become due on or prior to the next scheduled payment date (each, a "*Payment Date*"), which fraction will, for each type of such debt service, be equal to the number of months that have elapsed since the immediately preceding Payment Date over the number of months between such Payment Dates for such debt service; *provided* that, on any transfer date immediately preceding any Payment Date, the amounts transferred pursuant to this priority *third* shall be the amount required to cause the balance on deposit in the aggregate in the Payment Account to be sufficient to pay all debt service due and payable, after taking into consideration any other amounts to be paid from the Payment Account prior to the next transfer date. For the avoidance of doubt, amounts payable under this priority *third* shall not include amounts otherwise payable under priority *seventh* below;

fourth, on a monthly basis, to the Debt Service Reserve Account, an amount necessary, if any, to cause the balance on deposit in the aggregate in the Debt Service Reserve Account (including the available undrawn amount of any Acceptable LC credited to the Debt Service Reserve Accounts on such date), after transfers therein have been made on such transfer date, to equal the DSRA Requirement;

fifth, on a monthly basis, to the O&M Reserve Account, an amount necessary, if any, to cause the balance on deposit in the aggregate in the O&M Reserve Account (including the available undrawn amount of any Acceptable LC credited to the O&M Reserve Accounts on such date), after transfers therein have been made on such transfer date, to equal the O&M Reserve Requirement;

sixth, to the Prepayment Account, on any applicable transfer date, an amount equal to all mandatory prepayments or redemptions then required to be made in accordance with the Indenture, including any premiums or make-whole amounts payable in connection therewith;

seventh, on a monthly basis, (A) to the Prepayment Account, any outstanding reimbursement obligations or amounts of any loans (in each case including accrued interest) under the LC Facility Agreement as a result of the drawing under a Letter of Credit and (B) to the Letter of Credit Account, an amount, when taken together with all previous amounts deposited into the Letter of Credit Account prior to such date, equal to 102.5% of the aggregate undrawn amount available to be drawn on all issued and outstanding Letters of Credit as of such date;

eighth, to the Prepayment Account, on a Note Payment Date, for application to the Target Debt Balance Cash Sweep as described in "—*Cash Sweep Mandatory Redemption*;"

ninth, to the Prepayment Account, on a Note Payment Date, an amount equal to any optional prepayments or redemptions then permitted to be made in accordance with the Indenture, including any premiums or make-whole amounts payable in connection therewith; and

tenth, on a Note Payment Date, after the application of funds as provided under priorities *first* through *ninth* (inclusive) above, all remaining amounts on deposit in the Revenue Accounts to the Distribution Holding Account or any other Collateral Account as directed by the Issuer.

USD Loss Proceeds Account

The Obligors will deposit, and will use all reasonable efforts to cause third parties that would otherwise make payments directly to such Obligor to deposit, into the USD Loss Proceeds Account all Event of Loss Proceeds received by the applicable Obligor denominated in U.S. dollars upon receipt thereof, and the Onshore Collateral Agent or the Onshore Depositary Bank will deposit any such Event of Loss Proceeds received directly by it into the applicable USD Loss Proceeds Account upon receipt thereof.

The Obligors shall cause the amounts on deposit in the USD Loss Proceeds Account to be withdrawn and transferred for application (pursuant to a transfer certificate provided to the Onshore Collateral Agent prior to any such transfer): (i) to the Prepayment Account, for application to any mandatory prepayment or redemption required to be made in accordance the Indenture, (ii) to the Revenue Accounts, to reimburse the applicable Obligor for any expenses incurred as a result of rebuilding, replacing, repairing or restoring the Project (in which case, such proceeds may be made available for purposes of such rebuilding, replacing, repairing or restoring to the applicable Obligor or such other Person as directed by the applicable Obligor) or (iii) to the extent not either (x) otherwise required to be applied as indicated in clause (i) above or (y) applied as indicated in clause (ii) above, to the applicable Revenue Account.

Peso Loss Proceeds Account

The Obligors will deposit, and will use all reasonable efforts to cause third parties that would otherwise make payments directly to such Obligor to deposit, into the Peso Loss Proceeds Account all Event of Loss Proceeds received by such Obligor denominated in Chilean Pesos upon receipt thereof, and the Onshore Collateral Agent or the Onshore Depositary Bank will deposit any such Event of Loss Proceeds received directly by it into the applicable Peso Loss Proceeds Account upon receipt thereof.

The Obligors shall cause the amounts on deposit in the Peso Loss Proceeds Account to be withdrawn and transferred for application (pursuant to a transfer certificate provided to the Onshore Collateral Agent prior to any such transfer): (i) to the Prepayment Account, for application to any mandatory prepayment or redemption required to be made in accordance the Indenture, (ii) to the Revenue Accounts, to reimburse the applicable Obligor for any expenses incurred as a result of rebuilding, replacing, repairing or restoring the Project (in which case, such proceeds may be made available for purposes of such rebuilding, replacing, repairing or restoring to the applicable Obligor or such other Person as directed by the applicable Obligor) or (iii) to the extent not either (x) otherwise required to be applied as indicated in clause (i) above or (y) applied as indicated in clause (ii) above, to the applicable Revenue Account.

Operations Accounts

The Issuer and the Guarantors shall cause the Operations Accounts to be funded from (i) the applicable U.S. dollar-denominated or Peso-denominated Revenue Account and (ii) from the Unrestricted Accounts in accordance with the Security and Depositary Agreement.

To the extent of available funds, the Issuer and the Guarantors shall cause the funds on deposit in the applicable Operations Accounts to be withdrawn to pay O&M Costs then due and payable in the applicable denomination of such O&M Costs from the applicable Operations Account of the Issuer or applicable Guarantor. The Issuer and the Guarantors will be permitted to withdraw amounts for O&M Costs directly from its applicable Operations Account, without the requirement to provide a transfer certificate to the Onshore Collateral Agent in advance of such transfer. Notwithstanding the foregoing, with respect to any amounts so withdrawn, the Issuer and the Guarantors must apply such amounts exclusively to the payment of O&M Costs in accordance with the terms of the Indenture Documents.

Ranking

The Notes and the Note Guarantees:

- will be the Issuer's and the Guarantors' senior secured obligations;
- will be secured by a first priority Lien, subject to Permitted Liens, on the Collateral;
- will rank *pari passu* in right of payment with, and share equally and ratably in the Collateral with, any future Senior Secured Obligations;
- will rank senior in right of payment to all other Permitted Indebtedness (as defined below) that does not constitute Senior Secured Obligations to the extent of the value of the Collateral; and
- will be senior in right of payment to any existing and future subordinated Indebtedness of the Issuer and the Guarantors.

Additional Amounts

Any and all payments of principal of, premium, if an, and interest on or with respect to the Notes, by or on behalf of the Issuer, to noteholders, will be made free and clear of, and without withholding or deduction for or on account of, Taxes imposed by any Taxing Jurisdiction, unless required by Applicable Law. Subject to the exceptions described in more detail below, if any withholding or deduction on account of Taxes is required to be imposed by any Taxing Jurisdiction, the Issuer will:

- pay to the noteholders such additional amounts as may be necessary ("*Additional Amounts*") so that after making all required deductions or withholdings, including those applicable to additional sums payable under this heading, the net amount received by holders or other beneficial owners of the Notes will not be less than the amounts as would have been received by them had no such withholding or deduction been required,
- deduct or withhold such Taxes; and
- remit the full amount deducted or withheld to the relevant taxing or other Governmental Authority.

Notwithstanding the foregoing, no such Additional Amounts shall be payable for or on account of:

(1) any Taxes which would not have been imposed or levied on a holder but for the existence of any present or former connection between the holder or beneficial owner of the Notes and the relevant Taxing Jurisdiction, including, without limitation: (1) being or having been a citizen or resident for tax purposes of the relevant Taxing Jurisdiction, (2) maintaining or having maintained an office, permanent establishment or branch in the relevant Taxing Jurisdiction, or (3) being or having been present or engaged in a trade or business in the relevant Taxing Jurisdiction, except for a connection solely arising from the mere ownership of, or receipt of payment under, the Notes or the exercise of rights under the Notes or the Indenture, either personally or through the Trustee;

(2) any estate, inheritance, gift, or similar tax, assessment or other governmental charge;

(3) any Taxes that are imposed or levied by reason of the failure by the holder or beneficial owners of the Notes to timely comply, subject to the conditions described below, with a written request by or on behalf of the Issuer, to provide information, documentation or other evidence concerning (i) such holder or beneficial owner's nationality, residence, identity, eligibility for benefits under a treaty for avoidance of double taxation, (ii) such noteholder or beneficial owner's present or former connection with the relevant Taxing Jurisdiction or any political subdivision or territory or possession of the relevant Taxing Jurisdiction or are subject to its jurisdiction or (iii) any other information about the holder or beneficial owner that is necessary from time to time to determine the appropriate rate of deduction or withholding of Taxes applicable to that holder or beneficial owner, *provided* that (1) any information, documentation or other evidence requested is required under Applicable Law or treaties for the avoidance of double taxation to determine the respective deduction or withholding, and (2) at least 30 days prior to the first payment date with respect to which the Issuer shall apply this clause (c), the Issuer shall have notified the Trustee, in writing, that the holders or beneficial owners of the Notes will be required to provide that information, documentation or other evidence and requested that the Trustee provide notification thereof to the noteholders at the Issuer's expense;

(4) the presentation of the Notes, when required, for payment on a date more than 30 days after the date on which the payment became due and payable or the date on which payment is duly provided for, whichever occurs later, except to the extent that the holder or the beneficial owner of the Notes would have been entitled to Additional Amounts in respect of those Taxes on presenting the note for payment on any date during the 30-day period;

(5) any tax, duty, assessment or other governmental charge payable otherwise than by deduction or withholding from payments on or with respect to the Notes; and

(6) any combination of items (1) through (5) above.

Notwithstanding the foregoing, the limitations on the Issuer's obligation to pay Additional Amounts set forth in clause (3) above shall not apply if the provision of the certification, identification, information, documentation, declaration or other evidence described in such clause (3) would be materially more onerous, in form, in procedure or in the substance of information disclosed, to a holder or beneficial owner of the Notes, after taking into account any relevant differences between United States and Chilean law, regulation or administrative practice, than comparable information or other applicable reporting requirements imposed or provided for under United States federal income tax law, including the United States-Chilean Income Tax Treaty, including proposed regulations, and administrative practice, for example IRS Forms W-8BEN, W-9 and 6166.

Upon the Trustee's receipt of notification from the Issuer that the holders will be required to provide information or documentation as described in clause (3) above, the Trustee will provide notification thereof to the holders. The Issuer will provide the Trustee, the holders and the Paying Agent with a duly certified or authenticated copy of an original receipt of the payment of Taxes which the Issuer has withheld or deducted in respect of any payments made under or with respect to the Notes. The Trustee will, for a period of five years following the due date for each payment, maintain in its files each such certified copy received from the Issuer.

If the Issuer is obligated to pay Additional Amounts with respect to any payment under or with respect to the Notes other than Additional Amounts payable under the law as in effect on the date of the Indenture, the Issuer will deliver to the Trustee a certificate of a Responsible Officer stating the fact that Additional Amounts are payable and the amounts so payable.

In addition, the Issuer will pay any stamp, issue, registration, documentary or other similar Taxes and other duties (including interest and penalties with respect thereto) imposed or levied by any Taxing Jurisdiction (or any political subdivision or taxing authority thereof or therein) in respect of the creation, issue and offering of the Notes.

Any reference in this offering memorandum, the Indenture, any supplemental indenture or the Notes to principal, interest and premium, if any, or any other amount payable in respect of the Notes by the Issuer will be deemed also to refer to any Additional Amount that may be payable with respect to that amount under the obligations referred to in this subsection.

The obligations to make payments of Additional Amounts with respect to principal, interest or other amounts payable on the Notes or the Note Guarantees will survive any termination or discharge of the Indenture, payment of the Notes, discharge of the Note Guarantees and/or the resignation or removal of the Trustee or any Security Agent under the Indenture Documents.

Optional Redemption

The Notes are not redeemable at the option of the Issuer, except as set forth herein.

Optional Redemption prior to July 3, 2028.

Prior to July 3, 2028, the Issuer may redeem the Notes in whole or in part at any time, at its option, at a "make-whole" redemption price equal to the greater of (1) 100% of the principal amount of the Notes being redeemed and (2) the present value at such redemption date of all required interest and principal payments on such Notes through June 15, 2033 (excluding accrued but unpaid interest to the redemption date), discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate plus 50 basis points; plus in each case any accrued and unpaid interest and Additional Amounts, if any, on such Notes to, but excluding, the redemption date. Any redemption of Notes by the Issuer pursuant to this paragraph will be subject to either (i) there being at least US$200.0 million in aggregate principal amount of Notes outstanding after such redemption or (ii) the Issuer redeeming all of the then-outstanding principal amount of the Notes. The Trustee will have no obligation to calculate or verify any calculation of the redemption price.

"*Treasury Rate*" means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity or interpolated maturity (on a day count basis) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

"*Comparable Treasury Issue*" means the United States Treasury security or securities selected by an Independent Investment Banker as having an actual or interpolated maturity comparable to the remaining period until June 15, 2033 that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of a comparable maturity to the remaining period until June 15, 2033.

"*Independent Investment Banker*" means one of the Reference Treasury Dealers appointed by the Issuer.

"*Comparable Treasury Price*" means, with respect to any redemption date (1) the average of the Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotation or (2) if the Independent Investment Banker obtains fewer than four such Reference Treasury Dealer Quotations, the average of all such quotations.

"*Reference Treasury Dealer*" means either of Citigroup Global Markets Inc. or Goldman Sachs & Co. LLC, or any of their respective affiliates which is a primary United States government securities dealer, and not less than two other leading primary United States government securities dealers in New York City reasonably designated by the Issuer; provided that if the foregoing ceases to be a primary United States government securities dealer in New York City (a "*Primary Treasury Dealer*"), the Issuer will substitute therefor another Primary Treasury Dealer.

"*Reference Treasury Dealer Quotation*" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Independent Investment Banker, of the bid and asked price for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by such Reference Treasury Dealer at 3:30 p.m. New York time on the third Business Day preceding such redemption date.

Optional Redemption on or after July 3, 2028.

At any time and from time to time on or after July 3, 2028, the Issuer may redeem the Notes, at its option, in whole or in part, at the following redemption prices, expressed as percentages of the principal amount on the redemption date, *plus* Additional Amounts and accrued and unpaid interest to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant Note Payment Date to the extent that such date precedes the redemption date), if redeemed during the twelve-month period beginning on July 3 of each of the years set forth below:

Year	Percentage
2028	102.5625%
2029	101.7083%
2030	101.28125%
2031 and thereafter	100.0000%

Optional Redemption upon Equity Offerings.

Prior to July 3, 2024, the Issuer may, at its discretion, at any time or from time to time, use an amount not to exceed the net cash proceeds of one or more Eligible Equity Offerings to redeem up to 35% of the aggregate principal amount of the outstanding Notes (including any Additional Notes) at a redemption price equal to 105.125% of the principal amount on the redemption date, plus any accrued and unpaid interest to, but excluding, the redemption date; provided, that:

- after giving effect to any such redemption at least 65% of the aggregate principal amount of the Notes (including any Additional Notes) issued under the Indenture remains outstanding; and

- the Issuer will make such redemption not more than 90 days after the consummation of such Eligible Equity Offering.

Optional Tax Redemption.

The Issuer may redeem the Notes in whole but not in part at any time, at its option, at a redemption price equal to 100% of the principal amount of the Notes being redeemed, plus accrued and unpaid interest and Additional Amounts, if any, on such Notes to, but excluding, the redemption date, if, as a result of:

(1) any change in, or amendment to, laws or treaties (or any regulation or rulings promulgated thereunder) of a Taxing Jurisdiction; or

(2) any change in the official application, administration or interpretation of such laws, treaties, regulations or rulings in such jurisdictions,

which amendment, change, application, administration or interpretation is proposed and becomes effective on or after the Issue Date, the Issuer has become or would become obligated to pay any Additional Amounts (in excess of those attributable to Taxes that were applicable as of the Issue Date) on the next date on which any amount would be payable with respect of such Notes and the Issuer determines in good faith that such obligation cannot be avoided by taking commercially reasonable measures available to the Issuer; *provided*, *however*, that no such notice of redemption shall be given earlier than 90 days prior to the earliest date on which the Issuer would be obligated to pay such Additional Amounts. Notwithstanding anything to the contrary set forth herein, the Issuer shall not be entitled to make the election to redeem Notes contemplated in this section on the basis that (or as a result of) the jurisdiction of the paying agent having changed. For this purpose, commercially reasonable measures will not include any change in the Issuer's jurisdiction of establishment.

Prior to the giving of notice of redemption of such Notes pursuant to the foregoing paragraph, the Issuer will deliver to the Trustee (i) a certificate of a Responsible Officer to the extent that the obligation of the Issuer to pay Additional Amounts cannot be avoided by the Issuer taking commercially reasonable measures and (ii) a written

Opinion of Counsel independent of the Issuer in such Taxing Jurisdiction, as the case may be, to the effect that there has been or will become effective such changes or amendments which would entitle the Issuer to redeem the Notes hereunder. The Trustee will accept and shall be entitled to rely on such certificate of a Responsible Officer and the Opinion of Counsel as sufficient evidence of the existence and satisfaction of the conditions precedent as described above, in which event it shall be conclusive and binding on the noteholders.

Cash Sweep Mandatory Redemption

Upon each Note Payment Date, the Issuer will redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed, plus accrued and unpaid interest to the redemption date, plus Additional Amounts, if any (but without payment of any "make-whole" premium) in an amount (the "*Target Debt Balance Cash Sweep*") equal to the lesser of: (i) 100% of Available Cash (if any) and (ii) the total outstanding principal of the Notes as of such Note Payment Date less the applicable Target Debt Balance corresponding to such Note Payment Date (calculated after accounting for any principal payment made on such Note Payment Date); *provided that* if, following the redemption of a portion of a Note, the remaining principal amount of such Note outstanding immediately after such redemption would be less than US$200,000 and multiples of US$1,000 in excess thereof, then the portion of such Note so redeemed shall be reduced so that the remaining principal amount of such Note outstanding immediately after such redemption is not less than US$200,000 and multiples of US$1,000 in excess thereof. For the avoidance of doubt, once the total outstanding principal of the Notes is equal to the Target Debt Balance, the Issuer's obligations in respect of the Target Debt Balance Cash Sweep will be fulfilled for such Note Payment Date. The Target Debt Balance Cash Sweep for each Note Payment Date shall be applied in inverse order of maturity to each remaining scheduled redemption of principal due in respect of the Notes as of such Note Payment Date and in connection with any Target Debt Balance Cash Sweep, the Issuer will deliver to the Trustee a certificate of a Responsible Officer setting forth the amended amortization schedule for the Notes reflecting such application. The Issuer's failure to have any Available Cash on any Note Payment Date in order to pay the Target Debt Balance Cash Sweep will not give rise to any Default or Event of Default (as defined below).

Terms of Redemption

In the event that less than all of the Notes are to be redeemed at any time, selection of Notes for redemption will be made by the Trustee in compliance with the requirements governing redemptions of the principal securities exchange, if any, on which Notes are listed or if such securities exchange has no requirement governing redemption or the Notes are not then listed on a securities exchange, on a pro rata basis or by lot (or, in the case of Notes issued in global form, in accordance with the procedures of The Depository Trust Company ("*DTC*")), except as set forth under "—*Cash Sweep Mandatory Redemption*."

Notice of any redemption will be mailed by first-class mail, postage prepaid, at least 30 but not more than 60 days before the redemption date to noteholders to be redeemed at their respective registered addresses or otherwise in accordance with the procedures of the DTC. If Notes are to be redeemed in part only, the notice of redemption will state the portion of the principal amount thereof to be redeemed although no Note of US$200,000 in principal amount or less will be redeemed in part. A new Note in a principal amount equal to the unredeemed portion thereof, if any, which must be in integral multiples of US$1,000, will be issued in the name of the noteholder thereof upon cancellation of the original Note (or appropriate adjustments to the amount and beneficial interests in a global Note will be made, as appropriate). Notice of any redemption may be conditioned to the Issuer obtaining prior funding, except in the events described under "—*Cash Sweep Mandatory Redemption*."

Notes called for redemption will become due on the applicable redemption date. The Issuer will pay the redemption price for any Note, together with accrued and unpaid interest and Additional Amounts, if any, thereon, to, but excluding, the applicable redemption date; except in the case of an optional redemption under "—*Cash Sweep Mandatory Redemption*" made on a Note Payment Date where no interest shall be payable. On and after the applicable redemption date, interest will cease to accrue on Notes or portions thereof called for redemption as long as the Issuer has deposited with the paying agent funds in satisfaction of the applicable redemption price pursuant to the Indenture. Upon redemption of any Notes by the Issuer, such redeemed Notes will be cancelled.

For Notes which are represented by global certificates held on behalf of DTC, the Euroclear System ("*Euroclear*") or Clearstream Banking, *société anonyme* ("*Clearstream*"), notices may be given by delivery of the relevant notices to DTC, Euroclear or Clearstream for communication to entitled account holders in substitution for the aforesaid mailing.

Offers to Purchase

Event of Loss

Within 180 days after an Event of Loss with respect to the Projects occurs, we must (1) apply (or enter into a binding commitment within such 180-day period) the Net Available Amount received to rebuild, replace, repair or restore the Project (or affected portion thereof), and (2) provide to the Trustee within such 180-day period a Feasible Repair Certificate. For the avoidance of doubt, following an Event of Loss, any amount paid by the Issuer or any Guarantor to rebuild, repair or restore the Project (or affected portion thereof) in respect of such Event of Loss shall be counted toward the obligation in this paragraph irrespective of whether the Net Available Amount is received prior to or following such payment.

Any Net Available Amount received by or on behalf of the Issuer or any Guarantor as a result of any Event of Loss that is not applied as described above will be deemed "*Excess Loss Proceeds*"; *provided*, *however*, that to the extent that the Net Available Amount received in respect of any Event of Loss (1) exceeds the amount applied to restore the Projects (or the affected portion thereof) in accordance with the first paragraph of this covenant and (2) does not exceed US$5.0 million, such proceeds may be used for any purpose not prohibited under the Indenture. To the extent Excess Loss Proceeds with respect to any Event of Loss exceed US$5.0 million, the Issuer shall, within 30 days, make to all noteholders and all holders of Senior Secured Obligations an Offer to Purchase (as defined below) the maximum principal amount of Notes and other Senior Secured Obligations that may be purchased with the Excess Loss Proceeds (any such Offer to Purchase, an "*Excess Loss Offer*"), at a purchase price equal to 100% of the principal amount thereof (but without payment of any "make-whole" premium), together with accrued and unpaid interest and Additional Amounts, if any, to, but excluding, the applicable purchase date in accordance with the procedures set forth in the Indenture or the agreements governing the Senior Secured Obligations, as applicable; *provided* that if, following repurchase of a portion of a Note, the remaining principal amount of such Note outstanding immediately after such repurchase would be less than US$200,000, then the portion of such Note so repurchased shall be reduced so that the remaining principal amount of such Note outstanding immediately after such repurchase is US$200,000. Upon completion of any Excess Loss Offer, the amount of Excess Loss Proceeds will be reset at zero, and any Excess Loss Proceeds remaining after consummation of such Excess Loss Offer shall be deposited in the Revenue Accounts.

Dispositions

Within 180 days following the receipt of the Net Available Amount from a Disposition, the Issuer or such Guarantor may apply or enter into a binding commitment to apply up to an amount equal to 100% of such Proceeds to make any capital expenditure or purchase Replacement Assets (or enter into a binding agreement to make such capital expenditure or to purchase any such Replacement Assets); *provided* that such committed capital expenditure or purchase is consummated within 180 days after the date of such binding agreement.

Any Net Available Amount not applied or invested as provided in the preceding paragraphs will be deemed "*Excess Disposition Proceeds.*" When accumulated Excess Disposition Proceeds equal or exceed US$5.0 million, the Issuer shall, within 30 days, make to all noteholders and all holders of Senior Secured Obligations an Offer to Purchase the maximum principal amount of Notes and other Senior Secured Obligations that may be purchased with the Excess Disposition Proceeds (any such Offer to Purchase, an "*Excess Disposition Offer*"), at a purchase price equal to 100% of the principal amount thereof (but without payment of any "make-whole" premium), together with accrued and unpaid interest and Additional Amounts, if any, to, but excluding, the applicable purchase date in accordance with the procedures set forth in the Indenture; *provided* that if, following repurchase of a portion of a Note, the remaining principal amount of such Note outstanding immediately after such repurchase would be less than US$200,000, then the portion of such Note so repurchased shall be reduced so that the remaining principal amount of such Note outstanding immediately after such repurchase is US$200,000. Upon completion of any Excess Disposition Offer, the amount of Excess Disposition Proceeds will be reset at zero, and any Excess Disposition Proceeds remaining after consummation of such Excess Disposition Offer shall be deposited into the Revenue Accounts.

Change of Control

Within 30 days following the occurrence of a Change of Control, the Issuer or another Person must make an Offer to Purchase all of the Notes then outstanding at a purchase price equal to 101% of the outstanding principal amount of the principal amount thereof (but without payment of any "make-whole" premium) together with accrued and unpaid interest and Additional Amounts, if any, to, but excluding, the applicable purchase date in accordance with the procedures set forth in the Indenture; *provided* that if, following repurchase of a portion of a Note, the remaining principal amount of such Note outstanding immediately after such repurchase would be less than US$200,000, then the portion of such Note so repurchased shall be reduced so that the remaining principal amount of such Note outstanding immediately after such repurchase is US$200,000.

Offer to Purchase Procedures

An "*Offer to Purchase*" shall be made by the Issuer by mailing (or otherwise communicating in accordance with the applicable procedures of DTC) the notice required pursuant to the terms of the Indenture, with a copy to the Trustee. The Offer to Purchase will remain open for a period of 20 Business Days following its commencement, except to the extent that a longer period is required by Applicable Law (the "*Offer Period*"). No later than five Business Days after the termination of the Offer Period (the "*Purchase Date*"), the Issuer or applicable Guarantor will apply all Proceeds to the purchase of the aggregate principal amount of Notes and, if applicable, Senior Secured Obligations (on a pro rata basis, if applicable) required to be offered for purchase pursuant to the Indenture (the "*Offer Amount*") or, if less than the Offer Amount has been so validly tendered, all Notes and Senior Secured Obligations validly tendered in response to the Offer to Purchase. Payment for any Notes so purchased will be made in the same manner as interest payments are made.

If the Purchase Date is on or after an applicable interest record date and on or before the related Note Payment Date, any accrued and unpaid interest to the Purchase Date and Additional Amounts, if any, will be paid on the Purchase Date to the Person in whose name a Note is registered at the close of business on such record date.

On or before the Purchase Date, the Issuer will, to the extent lawful, accept for payment, on a pro rata basis to the extent necessary, the Offer Amount of Notes and Senior Secured Obligations or portions thereof validly tendered and not properly withdrawn pursuant to the Offer to Purchase, or, if less than the principal amount sought has been validly tendered and not properly withdrawn, all Notes and Senior Secured Obligations so tendered, in the case of the Notes in integral multiples of US$1,000; *provided* that if, following repurchase of a portion of a Note, the remaining principal amount of such Note outstanding immediately after such repurchase would be less than US$200,000, then the portion of such Note so repurchased shall be reduced so that the remaining principal amount of such Note outstanding immediately after such repurchase is US$200,000. If the aggregate principal amount of Notes and Senior Secured Obligations validly tendered and not properly withdrawn pursuant to an Offer to Purchase exceeds the amount of Proceeds, the Issuer shall select the Notes and such Senior Secured Obligations to be purchased on a pro rata basis on the basis of the aggregate accreted value or principal amount of tendered Notes and Senior Secured Obligations (provided that the selection of such Senior Secured Obligations shall be made pursuant to the terms of such Senior Secured Obligations).

The Issuer will deliver, or cause to be delivered, to the Trustee the Notes so accepted and a certificate of a Responsible Officer stating the aggregate principal amount of Notes so accepted and that such Notes were accepted for payment by the Issuer in accordance with the terms of the Indenture. In addition, the Issuer will deliver all certificates and instruments required, if any, by the agreements governing the Senior Secured Obligations. The Paying Agent or the Issuer, as the case may be, will promptly, but in no event later than five Business Days after termination of the Offer Period, mail (or otherwise deliver in accordance with the applicable procedures of DTC) to each tendering noteholder or holder or lender of Senior Secured Obligations, as the case may be, an amount equal to the purchase price of the Notes or Senior Secured Obligations so validly tendered and not properly withdrawn by such holder or lender, as the case may be, and accepted by the Issuer for purchase, and the Issuer will promptly issue a new Note, and the Trustee, upon delivery of an authentication order from the Issuer, will authenticate and mail (or otherwise deliver in accordance with the applicable procedures of DTC) (or cause to be transferred by book entry) such new Note to such holder (it being understood that, notwithstanding anything in the Indenture to the contrary, no Opinion of Counsel or certificate of a Responsible Officer will be required for the Trustee to authenticate and mail or deliver such new Note) in a principal amount equal to any unpurchased portion of the Note surrendered; provided that each such new Note will be in a principal amount of US$200,000 or an integral multiple of US$1,000 in excess thereof. In addition, the Issuer will take any and all other actions required by the agreements governing the Senior Secured Obligations. Any Note not so accepted will be promptly mailed or delivered by the Issuer to the holder thereof.

Notwithstanding the foregoing, in connection with any "*Offer to Purchase*" under this section at a price of at least 100% of the principal amount of the Notes tendered, plus accrued and unpaid interest thereon to, but excluding, the applicable tender settlement date, if holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in such tender offer and the Issuer, or any third party making such tender offer in lieu of the Issuer, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer or such third party will have the right, upon not less than 30 nor more than 90 days' prior notice, given not more than 30 days following such purchase date, to redeem all Notes that remain outstanding following such purchase at a price equal to the price offered to each other holder in such tender offer plus, to the extent not included in the tender offer payment, accrued and unpaid interest to but excluding the date of redemption.

The Issuer will comply with Rule 14e-1 under the Exchange Act (to the extent applicable) and all other Applicable Laws in making any Offer to Purchase, and the above procedures will be deemed modified as necessary to permit such compliance. To the extent that the provisions of any Applicable Laws or regulations conflict with provisions of this covenant, the Issuer will comply with the Applicable Laws and regulations and will not be deemed to have breached its obligations under this covenant by virtue of its compliance with such Applicable Laws or regulations.

The Issuer and the Guarantors will agree in the Indenture to obtain all necessary consents and approvals from any Governmental Authority for any required remittance of funds outside of any jurisdiction in connection with any Offer to Purchase.

Offers to Purchase may not be conditional, *provided*, *however*, that an Offer to Purchase made in connection with a Change of Control may be made in advance of a Change of Control and conditioned upon the consummation of such Change of Control, if a definitive agreement is in place for the Change of Control at the time the Offer to Purchase is made.

The Issuer will not be required to make any Offer to Purchase pursuant to the terms of the Indenture if (1) a third party makes the Offer to Purchase in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to an Offer to Purchase made by the Issuer and purchases all Notes properly tendered and not withdrawn under the Offer to Purchase or (2) notice of redemption for all outstanding Notes has been given pursuant to the Indenture as described above under the captions "*—Optional Redemption*" unless and until there is a default in payment of the applicable redemption price.

The Issuer's ability to pay cash to the noteholders under an Offer to Purchase as a result of a Change of Control may be limited by the Issuer's or the Guarantors' then-existing financial resources. There can be no assurance that sufficient funds will be available, when necessary, to make the required purchase of the Notes.

The provisions under the Indenture relating to the Issuer's obligation to make an Offer to Purchase may be waived or amended as described in "*—Amendments, Supplements and Waivers.*"

Certain Covenants

Limitation on Indebtedness

The Issuer shall not create, incur or assume or suffer to exist any Indebtedness or issue Disqualified Stock and the Guarantors shall not incur any Indebtedness or issue Disqualified Stock, other than the following Indebtedness (which we refer to as "*Permitted Indebtedness*"):

(i) the obligations pursuant to the Indenture Documents (including the Indebtedness evidenced by the Notes issued on the Issue Date and the related Note Guarantees but excluding any Additional Notes);

(ii) current accounts payable arising, and accrued expenses incurred, in the ordinary course of business which are payable in accordance with customary practices that are not overdue for more than 90 days or are being contested in good faith;

(iii) Indebtedness in respect of non-speculative Hedging Obligations;

(iv) Permitted Refinancing of any Permitted Indebtedness incurred under clauses (1) and (7) of this paragraph;

(v) Indebtedness constituting reimbursement obligations with respect to letters of credit (other than under the LC Facility Agreement), surety, performance bonds, completion guarantees, judgments, advance payment, customs, tax guarantees and bank guarantees, in each case issued in the ordinary course of business;

(vi) Permitted Investments (to the extent the same constitute Indebtedness);

(vii) Intercompany Loans;

(viii) Indebtedness incurred under the LC Facility Agreement;

(ix) Permitted Subordinated Indebtedness in an amount not to exceed US$10.0 million (or its equivalent);

(x) Indebtedness of the Issuer or any Guarantor outstanding on the Issue Date;

(xi) Purchase Money Indebtedness and Capitalized Lease Obligations to the extent incurred in the ordinary course of business to finance the acquisition of items of equipment; provided that (x) if such obligations are secured, they are secured only by Liens upon the equipment being financed and (y) the aggregate principal amount of all such Purchase Money Indebtedness and the capitalized portion of such Capitalized Lease Obligations do not at any one time exceed US$10.0 million (or its equivalent) in the aggregate; and

(xii) Indebtedness of the Issuer or any Guarantor incurred in the ordinary course of business, consisting in one or more unsecured revolving credit facilities with one or more commercial banks or other financial institutions, in an amount not to exceed individually or in the aggregate US$2.0 million (or its equivalent).

For purposes of determining compliance with any restriction on the incurrence of Indebtedness, the U.S. dollar amount of Indebtedness denominated in a currency other than the U.S. dollar shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was incurred; provided that, the principal amount of any Permitted Refinancing Indebtedness shall be calculated based on the currency exchange rate that is in effect on the date of such refinancing.

Limitation on Liens

Neither the Issuer nor any Guarantor will directly or indirectly, create, incur, assume or suffer to exist any Lien of any kind on any Property now owned or hereafter acquired, except for the following ("*Permitted Liens*"):

(i) Liens in favor of all of the Secured Parties specifically created or required to be created by the Indenture, any other Indenture Document or the LC Facility Agreement;

(ii) Liens, deposits or pledges incurred or created in the ordinary course of business or under applicable Governmental Rules in connection with or to secure the performance of bids, tenders, contracts, leases, statutory obligations, surety bonds or appeal bonds;

(iii) Mechanics', materialmen's, workers', repairmen's, employees', warehousemen's or carriers' Liens or other like Liens arising in the ordinary course of business or under Governmental Rules securing obligations incurred in connection with the Issuer's business which are not yet due, or which are adequately bonded and which are being contested;

(iv) Liens imposed by Applicable Law for taxes, assessments, governmental charges or labor claims, in each case that are secured by a bond or which are not yet due or which are being contested in good faith by appropriate proceedings and as to which the Issuer shall have set aside on its books such reserves as may be required pursuant to IFRS;

(v) Liens on property or assets under construction (and related rights) in favor of a contractor or developer or arising from progress or partial payments by a third party relating to such property or assets; *provided* that such Liens shall be subject to customary lien waivers upon the making of progress payments;

(vi) Liens created by or resulting from any litigation or legal proceeding as to which the execution thereof has been effectively stayed while the underlying claims are being contested in good faith by appropriate proceedings, so long as such litigation, legal proceeding or claim does not give rise to an Event of Default;

(vii) defects, easements, rights of way, zoning restrictions, irregularities, encumbrances (other than for borrowed money) and clouds on title, any interest or title of a licensor, lessor or sublicensor or sublessor under any license or sublicense and statutory Liens that do not materially impair the value or use of the Property affected and that do not individually or in the aggregate materially impair the validity, perfection or priority (except Liens granted priority by operation of law) of the Liens granted under the Security Documents;

(viii) Liens securing Hedging Obligations which are permitted under the Indenture;

(ix) Liens securing or arising by reason of any netting or set-off arrangement entered into in the ordinary course of banking activities;

(x) Liens securing judgments for the payment of money which would not, assuming the effect of any required notice or passage of time, constitute an Event of Default under clause 7 thereof, so long as such Liens are adequately bonded and any appropriate legal proceedings that may have been duly initiated for the review of such judgment have not been finally terminated or the period within which such proceedings may be initiated has not expired;

(xi) Liens in favor of the Issuer or any of the Guarantors;

(xii) Liens in existence on the Issue Date that do not secure Indebtedness for borrowed money;

(xiii) Liens in existence on the Issue Date securing Indebtedness to be repaid with proceeds of the Notes, *provided* that, (i) all such outstanding obligations shall be repaid in full on the Issue Date, (ii) release (*alzamiento*) of all Liens created to secure any such obligations shall have been duly executed and delivered by the parties thereto, and the corresponding Collateral Agent shall have received satisfactory evidence from local counsel, to the Secured Parties or otherwise, that the release has been duly executed (pending notarization and registration of such release with the appropriate registries or ledgers which shall be carried out as described in (iv) below), (iii) the Liens to be created under the Security Documents shall be created on the Issue Date, subject to the grace periods provided in the Indenture and the Security Documents, (iv) any filings, recordings, notices and other actions required under Applicable Law for the release and discharge of the Liens securing the Existing Indebtedness shall have been filed with the applicable registrars or Governmental Authority or taken, as the case may be, as soon as practicable, but in any event no more than 15 Business Days following the Issue Date, (v) any filings, recordings, notices and other actions required under

Applicable Law, to perfect and record the Liens created under the Security Documents shall have been filed with the applicable registrars or Governmental Authority or taken, as the case may be, as soon as practicable, but in any event no more than 20 Business Days following the Issue Date, (vi) as soon as reasonably practicable after the Issue Date and, with respect to pledges, in any event within 45 days following the Issue Date, obtain the registration of the release of the pledges and the registration of the pledges created pursuant to the Security Documents, together with delivery to the Onshore Collateral Agent of evidence of such registration and, with respect to mortgages, as soon as reasonably practicable after the Issue Date and, in any event within 60 calendar days following the Issue Date, obtain the registration of the release of the mortgages and the registration of the mortgages created pursuant to the Security Documents, together with delivery to the Onshore Collateral Agent of evidence of such registration and (vii) as soon as reasonably practicable after the Issue Date, and in any event within 60 calendar days following the Issue Date, perform all the necessary notices, acceptances, and other actions required under Applicable Law in order to fully perfect the Liens created under the Security Documents together with delivery to the Onshore Collateral Agent of evidence of each such registration, recordation and perfection of the first priority ranking Lien created thereby, including those set forth in the Indenture;

(xiv) Liens securing Purchase Money Indebtedness and Capitalized Lease Obligations described under clause (11) of the definition of Permitted Indebtedness; and

(xv) any extension, renewal or replacement (or successive extensions, renewals or replacements), in whole or in part, of any Lien referred to in the foregoing clauses, or of any Indebtedness secured thereby; provided that the principal amount of Indebtedness so secured thereby shall not exceed the principal amount of Indebtedness so secured at the time of such extension, renewal or replacement, and that such extension, renewal or replacement Lien shall be limited to all or part of the Property that secured the Lien extended, renewed or replaced (plus improvements on or additions to such property or asset).

Restricted Payments

Neither the Issuer nor any Guarantor shall:

(i) declare or pay any dividend or make any other payment or distribution on account of the Issuer or such Guarantor's Equity Interests or to the direct or indirect holders of the Issuer's or such Guarantor's Equity Interests in their capacity as such, other than, in each case, (i) dividends or distributions payable in Equity Interests (except Disqualified Stock) of the Issuer or such Guarantor and (ii) dividends or distributions payable to the Issuer or such Guarantor;

(ii) purchase, redeem or otherwise acquire or retire for value any Equity Interests of the Issuer or such Guarantor or any direct or indirect parent of the Issuer or such Guarantor;

(iii) make any payment on or with respect to, or purchase, redeem, defease or otherwise acquire or retire for value any Indebtedness of the Issuer or such Guarantor that is contractually subordinated to the Notes or the Note Guarantees (other than Intercompany Loans permitted under clause (7) of the definition of "Permitted Indebtedness", other than solely with the proceeds from a Permitted Equity Issuance or Permitted Subordinated Indebtedness; or

(iv) make any Investment other than a Permitted Investment;

(all such payments and other actions set forth in these clauses (1) through (4) above being collectively referred to as "*Restricted Payments*").

Notwithstanding the foregoing, the Issuer and any Guarantor will be entitled to remit funds from the Distribution Holding Account to the Distribution Account (a "*Distribution*"), only if all of the following conditions are satisfied (such conditions being referred to collectively as the "*Distribution Release Conditions*"):

(i) no Default shall have occurred and be continuing or would occur from the making of such Distribution;

(ii) the Debt Service Coverage Ratio for the twelve-month period ending with the month most recently ended (taken as one accounting period), or, with respect to the period prior to the expiration of the first full twelve-month period following the Issue Date, for the period from the Issue Date until the month most recently ended (taken as one accounting period), in each case is at least 1.20:1.00 and the Projected Debt Service Coverage Ratio for the twelve-month period following the date of determination beginning with the month that most recently ended (taken as one accounting period) is at least 1.20:1.00;

(iii) each of the Debt Service Reserve Account and the O&M Reserve Account shall have been fully funded (including with an Acceptable LC) to the applicable required balance and all other transfers required to be made to or from the Collateral Accounts required by the Indenture Documents and the Security and Depositary Agreement on or prior to the date of such Distribution have been made immediately prior to such Distribution;

(iv) no loans under the LC Facility Agreement shall be outstanding;

(v) such payment shall be made no more than 45 days after the most recent payment of principal under the Notes has been made; and

(vi) not later than the date of making a Distribution, the Issuer shall deliver to the Trustee and the Offshore Collateral Agent a certificate of a Responsible Officer of the Issuer including the Debt Service Coverage Statement and certifying that such Distribution complies, or will comply, with the Indenture.

If the conditions contemplated above are satisfied, the Issuer or the applicable Guarantor will be permitted to deliver written instructions to the Offshore Depositary Bank, that the Offshore Depositary Bank withdraw money on deposit in the Distribution Holding Account as of the date on which such conditions have been satisfied and transfer such money from the Distribution Holding Account to the applicable Distribution Account as instructed by the Issuer in writing.

Leases

No Guarantor shall enter into any agreement, or be or become liable as lessee under any agreement, for the lease, hire or use of any Property, except for (i) operating leases of Property (which do not constitute Capitalized Lease Obligations) and (ii) the Ground Leases existing on the Issue Date and any extensions or renewals thereof; *provided* that any Guarantor's aggregate payment obligations under all such operating leases shall not exceed US$5.0 million in any calendar year. No Guarantor shall enter into any Sale and Lease-Back Transaction.

Merger or Consolidation, Sale of Property and Disposition or Purchase of Property

Neither the Issuer nor any Guarantor will, directly or indirectly: (1) merge into or consolidate with any other Person (whether or not such Guarantor is the surviving corporation) or change its form of organization; (2) sell, lease, convey or otherwise dispose of (or permit or consent to the sale, lease, conveyance or other disposition of) all or substantially all of its Property, in each case, in one or more related transactions, to any Person; or (3) make any other Disposition, other than:

(i) sales or other Dispositions of Permitted Investments (including the unwinding of any Hedging Obligations entered into in accordance with the Indenture);

(ii) Restricted Payments permitted under the Indenture;

(iii) Affiliate Transactions (as defined below) permitted under the Indenture; or

(iv) sales or other Dispositions of Obsolete Assets; *provided* that, if the amount of all such sales or other Dispositions of Obsolete Assets by any Guarantor during any fiscal year exceeds US$5.0 million, such Guarantor shall deliver to the Trustee a certificate of a Responsible Officer of such Guarantor stating that (a) such Disposition is for Fair Market Value and (b) at least 90% of the consideration therefor received by the Issuer or the applicable Guarantor is in the form of cash, Cash Equivalents or Replacement Assets or any combination thereof. (For these purposes, the assumption by the purchaser of Indebtedness or other obligations of the Issuer or any Guarantor (other than Permitted Subordinated Indebtedness) pursuant to customary arrangements, and instruments or securities received from the purchaser that are promptly, but in any event within 30 Business Days of the closing, converted by the Issuer or any Guarantor to cash or Cash Equivalents, to the extent of the cash or Cash Equivalents actually so received, shall be considered cash or Cash Equivalents, as applicable, received at closing).

Notwithstanding the foregoing, any Guarantor may consolidate with, merge into or transfer all of its Properties to the Issuer or another Guarantor for the purposes of an internal reorganization, which, for the avoidance of doubt, shall include any payment made to the Issuer or a Guarantor in connection with any merger or consolidation.

No Guarantor shall purchase or acquire any Property other than (1) Property which is reasonably required in connection with a Permitted Business, (2) cash or Cash Equivalents or (3) Permitted Investments.

The Issuer shall not acquire or own any Subsidiary or other Properties, except (i) the Guarantors, (ii) Permitted Investments, (iii) the Notes (and Additional Notes), (iv) other non-material Properties, or (v) in connection with a Permitted Business.

Transactions with Affiliates

Neither the Issuer nor any Guarantor will (1) make any Investment in or any payment to, (2) sell, lease, transfer, assign or otherwise dispose of any of its Property to, (3) purchase or acquire Property from or (4) enter into or make or amend any transaction, contract, agreement, arrangement, understanding, loan, advance or guarantee with, or for the benefit of, any Affiliate (each, an "*Affiliate Transaction*"), unless the Affiliate Transaction is on terms no less favorable to the Issuer or such Guarantor than could be obtained in a comparable arm's-length transaction with a Person that is not an Affiliate.

Prior to entering into any Affiliate Transaction for any transaction amount in excess of US$5.0 million, the Issuer or applicable Guarantor shall deliver to the Trustee a certificate of a Responsible Officer of such Issuer or applicable Guarantor stating that such Affiliate Transaction complies with the Indenture.

These restrictions and conditions shall not apply to (i) any Affiliate Transaction between or among the Issuer and any Guarantor or among Guarantors not otherwise restricted under the Indenture, (ii) any Distribution, any withdrawal from the Distribution Holding Account or use of funds from the Distribution Account in accordance with the covenant described under "*—Restricted Payments*" or (iii) Affiliate Transactions existing on the Issue Date described under "*Transactions with Affiliates*" in this offering memorandum (including any renewal or extension of such existing Affiliate Transaction that is on substantially similar terms as such existing Affiliate Transaction).

Use of Proceeds

The Issuer shall use the net proceeds from the offering of the Notes in the manner set forth in this offering memorandum under "*Use of Proceeds*."

Performance of Material Project Documents

The Issuer and each Guarantor shall perform and observe in all material respects the covenants and agreements contained in any of the Material Project Documents to which it is or becomes a party, and shall take all necessary action to prevent the termination of any of such Material Project Documents in accordance with the terms thereof or otherwise (other than by virtue of the scheduled expiration in the ordinary course of such Material Project Document in accordance with its terms), unless

(1) the Issuer or such Guarantor obtains a Ratings Affirmation in connection with such failure to perform and observe or such termination or

(2) the Issuer or such Guarantor shall deliver to the Trustee (x) a certificate of a Responsible Officer of the Issuer or such Guarantor stating that such failure to perform and observe or such termination would not reasonably be expected to result in a Material Adverse Effect, (y) solely in the case of a failure to comply with or observe, in all material respects, any covenants and agreements contained in the relevant Material Project Document, written verification by the Independent Engineer that such failure to perform and observe would not reasonably be expected to result in a material adverse effect on the viability of the Projects, taken as a whole, and (z) solely in the case of a failure to take all necessary action to prevent the termination of such Material Project Document, (i) written verification by the Independent Engineer that such termination would not reasonably be expected to result in a material adverse effect on the viability of the Projects taken as a whole; or (ii) the Issuer or Guarantor shall have delivered to the Trustee one or more Additional Material Project Documents within one hundred and twenty (120) days, together with a certificate of a Responsible Officer certifying that the terms are substantially similar or materially no less favorable to the Issuer or the Guarantors than the Material Project Document being terminated; or (iii) the Issuer or such Guarantor shall have delivered to the Trustee a written report from a reputable market consultant certifying that projected prices in the spot market would reasonably be expected to produce sufficient Project Revenues to satisfy scheduled payments under the Notes.

The Issuer and each Guarantor shall instruct all Project Parties to make all payments payable to the Issuer or any Guarantor to the Onshore Depositary Bank for deposit in the applicable Guarantor Revenue Accounts in accordance with the Security and Depositary Agreement.

Amendment of Material Project Documents and Additional Material Project Documents

Neither the Issuer nor any Guarantor shall (1) amend, supplement, modify in any material respect or give any consent to or waiver of any material matter under any Material Project Document or (2) except as required or otherwise permitted by the Indenture Documents, enter into any Additional Material Project Document, unless in either case the Issuer or such Guarantor shall deliver to the Trustee (x) a certificate of a Responsible Officer of the Issuer or such Guarantor describing the relevant action and stating that such action would not reasonably be expected to result in a Material Adverse Effect and (y) written verification by the Independent Engineer that such action would not reasonably be expected to result in a material adverse effect on the viability of the Projects, taken as a whole.

Certain Agreements

Neither the Issuer nor any Guarantor shall enter into any agreement or undertaking other than the Transaction Documents or as otherwise permitted pursuant to the terms of the Indenture Documents, restricting, or purporting to restrict, in any material respect, the ability of any of them to comply with the terms of the Indenture or to amend the Indenture or any other Indenture Document.

Security Documents; Future Guarantees

(1) Each of the Issuer and the Guarantors shall take, or cause to be taken, all actions necessary to maintain each Security Document to which it is a party in full force and effect and enforceable in accordance with its terms and to maintain and preserve the Liens created by such Security Documents and the priority thereof, including (i) making filings and recordations, (ii) making payments of fees and other charges on a timely basis, (iii) issuing and, if necessary, filing or recording supplemental documentation, including continuation statements, declaration or amendment deeds, discharging all claims or other Liens adversely affecting the rights of any Secured Party in any Collateral, publishing or otherwise delivering notice to third parties, (iv) depositing title

documents and (v) taking all other actions either necessary or otherwise reasonably requested by the relevant Collateral Agent (acting at the instruction of the Trustee, who shall act as directed by the Majority Holders) to ensure that all Collateral (including any after-acquired Property of the Issuer or a Guarantor, as applicable, in each case intended to be covered by any Security Document to which it is a party) is subject to a valid and enforceable first-priority Lien in favor of the relevant Collateral Agent for the benefit of the Secured Parties (except as otherwise permitted under the Indenture Documents). In furtherance of the foregoing, (A) each of the Issuer and the Guarantors shall ensure that all of its after-acquired Property, subject to any exemptions therein or under the Indenture, other than such Property not intended to be covered by such Security Documents shall become subject to the Lien of the Security Documents having the priority contemplated thereby promptly upon the acquisition thereof and (B) each of the Issuer and the Guarantors shall not open or maintain any bank account (other than the Distribution Account and the Unrestricted Account) without first taking all such actions as may be necessary or otherwise requested by the Collateral Agents (acting at the instruction of the Trustee, who shall act as directed by the Majority Holders) to ensure that such bank account is subject to a valid and enforceable first priority Lien in favor of the relevant Collateral Agent for the benefit of the Secured Parties.

(2) Each of the Issuer and the Guarantors shall take, or cause to be taken, all actions necessary to cause each Additional Material Project Document intended to be covered by a Security Document to which it is a party to be or become subject to the Liens of the Security Documents (whether by amendment to any Security Document, execution of a declaration deed or a new Security Document or otherwise) in favor of the relevant Collateral Agent, and shall deliver or cause to be delivered to the relevant Collateral Agent such certificates or other documents with respect to each Additional Material Project Document as are necessary or as the relevant Collateral Agent (acting at the instruction of the Trustee, who shall act as directed by the Majority Holders) may reasonably request, in each case to the extent required by the Security Documents.

(3) Each of the Issuer and the Guarantors shall grant (and shall take all actions necessary to cause) a first priority Lien in favor of the relevant Collateral Agent for the benefit of the Secured Parties on any future Property, in each case to the extent required by the Security Documents and subject to Permitted Liens.

(4) On the Issue Date and or at such other times as the Trustee may reasonably request in writing, each of the Issuer and the Guarantors shall furnish, or cause to be furnished, to the Trustee and the Collateral Agents, an opinion or Opinions of Counsel either stating that, in the opinion of such counsel, such action has been taken pursuant to the terms of the Security Documents with respect to (i) amending or supplementing the Security Documents (or providing additional Security Documents, notifications or acknowledgments) as is necessary to subject all the Collateral (including any after-acquired Property of the Issuer or the Guarantors, as applicable, in each case intended to be covered by a Security Document) to the Lien of the Security Documents and (ii) (A) the recordation of the Security Documents (including, without limitation, any amendment or supplement thereto) and any other requisite documents and (B) the execution and filing of any financing statements and continuation statements as are necessary to perfect and maintain the Liens purported to be created by the Security Documents and reciting the details of such action or stating that, in the opinion of such counsel, no such action is necessary to perfect and maintain such Liens. Such opinion or opinions of counsel shall also describe the recordation of the Security Documents and any other requisite documents and the execution and filing of any financing statements and continuation statements, or the taking of any other action that will, in the opinion of such counsel, be required to perfect and maintain the Liens purported to be created by the Security Documents after the date of such opinion.

Subject to the terms of the Indenture and the Security Documents, the Issuer and the Guarantors will have the right to remain in possession and retain exclusive control of the Collateral securing the Notes, to freely operate the Collateral and to collect, invest and dispose of any income therefrom.

(5) The Issuer shall cause any Subsidiary formed or acquired by the Issuer or any Guarantor after the Issue Date, (a) within 10 Business Days of such formation or acquisition, to enter into a supplement to the Indenture pursuant to which such entity shall guarantee, jointly and severally with the other Guarantors, all obligations under the Notes and the Indenture and (b) to the extent required by the Security Documents, all Equity Interests and other Property of assets of such entity shall be pledged as Collateral for the benefit of the Secured Parties in accordance with the terms of the Security Documents.

Transfers of Equity Interests

Except as specifically provided for in the covenant described under "*—Merger or Consolidation, Sale of Property and Dispositions, or Purchase of Property*", no Guarantor shall (a) permit or consent to the transfer (by assignment, sale or otherwise) of any of its Equity Interests, or (b) issue any new Equity Interests; *provided*, that any Guarantor may permit or consent to the assignment, sale or transfer of its Equity Interests or to the issuance of new Equity Interests in each case to the Issuer or another Guarantor (each a "*Transfer*") if such Transfer is consummated in compliance with the terms of the Indenture and each of the following conditions:

(i) after giving effect to any such Transfer, no Change of Control shall have occurred;

(ii) such Transfer shall be made expressly subject to the granting of a Lien in favor of the relevant Collateral Agent on the Equity Interests so being transferred, and any Person that owns any Equity Interest in a Guarantor as a result of such Transfer shall, simultaneously with such Transfer, sign a pledge agreement substantially similar to the Pledge Agreements; and

(iii) such Person referred to in paragraph (2) above shall, within 10 Business Days of such Transfer, execute and deliver to the relevant Collateral Agent such documents and instruments necessary or as such Collateral Agent may reasonably request in order to evidence, secure, and perfect such Collateral Agent's security interest in and Lien on such Equity Interests.

For the avoidance of doubt, this limitation shall not restrict the ability of any Guarantor to enter into a Pledge Agreement or any other pledge agreement with respect to any Equity Interests of such Guarantor with the relevant Collateral Agent.

Inspection

The Issuer will permit representatives of the noteholders, the Trustee, and any Collateral Agent under guidance of officers of the Issuer, to visit and inspect any of the properties of the Issuer or the Guarantors and to examine the Issuer's or such Guarantor's corporate, financial, operating and other records, no more than one time per year at the expense of the noteholders and at such reasonable times during normal business hours, upon reasonable advance written notice to the Issuer and with the Issuer's consent (such consent not to be unreasonably withheld); provided that when an Event of Default exists, representatives of the noteholders, the Trustee and any Collateral Agent may do any of the foregoing as often as may be reasonably desired at the expense of the Issuer at any time during normal business hours and without advance notice. The Issuer and the Guarantors will not be required to disclose information to the noteholders, the Trustee or any Collateral Agent that is prohibited by Applicable Law or contract (provided that such prohibition is not entered into in contemplation of this covenant) or is subject to attorney-client or similar privilege or constitutes attorney work product.

Governmental Approvals

Each Guarantor shall from time to time obtain and maintain, or cause to be obtained and maintained, each Governmental Approval as shall now or hereafter be required under Applicable Law, except if (1) the inability to obtain, or the rescission, termination, modification or suspension of such Governmental Approval is being contested in good faith by appropriate proceedings and (2) the failure to obtain or maintain such Governmental Approval or any such proceedings would not reasonably be expected to result in a Material Adverse Effect.

Insurance

The Issuer and each Guarantor shall maintain or cause to be maintained in full force and effect, with insurers of international standing, insurance coverage for each Project in relation to its operations and Property in such amounts and against such risks as is customarily maintained by companies operating in Chile engaged in the same or similar businesses as the Issuer and such Guarantor, as applicable. All insurance must be placed with insurance companies with financially sound and reputable insurers that have adequate capital and a credit rating no lower than the insurance companies providing insurance to the Issuer and the Guarantors on the Issue Date.

Such insurance shall name (i) such Guarantor as named insured and loss payee and (ii) note the interest of the relevant Collateral Agent thereon as a mortgagee and loss payee and all the Secured Parties as additional insured parties under third-party liability insurance policies. The Guarantors will cause all Event of Loss Proceeds to be applied in accordance with the Indenture.

Project Maintenance

The Issuer and each Guarantor shall maintain and preserve the Projects in good working order and in such condition that the Projects will have the capacity and functional ability to perform, on a continuing basis (ordinary wear and tear excepted), in normal commercial operation, in each case, pursuant to the Material Project Documents to which such Guarantor is a party.

The Issuer and each Guarantor shall cause the Projects to be operated, serviced, maintained and repaired so that the condition and operating efficiency thereof will be maintained and preserved (ordinary wear and tear excepted) in all material respects in accordance and compliance with (1) Prudent Industry Practices, (2) such operating standards as shall be required to enforce any material warranty claims against dealers, manufacturers, vendors, contractors, and sub-contractors and (3) the terms and conditions of all insurance policies maintained with respect to the Projects at any time, in each case, unless the failure to perform any such action would not reasonably be expected to result in a Material Adverse Effect.

Maintenance of Existence; Business Activities

Each of the Issuer and the Guarantors shall (1) preserve and maintain its legal existence under the Applicable Law of its jurisdiction of organization and all of its material licenses, rights, privileges and franchises necessary for the maintenance of its corporate existence, (2) comply, in all material respects, with its Organizational Documents, (3) engage solely in a Permitted Business, (4) refrain from making any amendments to its Organizational Documents other than those that would not reasonably be expected to (x) result in a Material Adverse Effect or (y) increase the risk of the Issuer or such Guarantor being consolidated with another Person (other than the Issuer or another Guarantor) in the event of a bankruptcy of the Issuer or such Guarantor (including, for the avoidance of doubt, amendments necessary in connection with a merger or consolidation of any of the Issuer or the Guarantors permitted under "*Certain Covenants—Merger or Consolidation, Sale of Property and Dispositions, or Purchase of Property*").

Compliance with Laws

Each of the Issuer and the Guarantors shall conduct its business and shall operate the Projects in compliance with, all requirements of Applicable Law, including all applicable Governmental Approvals and Environmental Laws, except where any failure to comply would not individually or in the aggregate reasonably be expected to result in a Material Adverse Effect, and except that any of the Issuer or the Guarantors may, at their expense, contest by appropriate proceedings conducted in good faith the validity or application of any such requirement of Applicable Law, so long as (1) none of the Secured Parties would be subject to any liability for failure to comply therewith and (2) the institution of such proceedings would not reasonably be expected to result in a Material Adverse Effect.

Payment of Taxes, etc.

Each of the Issuer and the Guarantors shall duly pay and discharge before they become overdue all Taxes, assessments and other governmental charges or levies imposed by a Governmental Authority upon it or its Property, income or profits except to the extent that such Taxes would not reasonably be expected to result in a Material Adverse Effect; *provided* that any of the Issuer or the Guarantors may contest in good faith any such tax, assessment, charge, levy, claim or obligation and, in such event, may permit the tax, assessment, charge, levy, claim or obligation to remain unpaid during any period, including appeals, when the Issuer or such Guarantor is in good faith contesting the same by proper proceedings, so long as (1) adequate reserves shall have been established with respect to any such tax, assessment, charge, levy, claim or obligation, accrued interest thereon and potential penalties or other costs relating thereto, or other adequate provision for payment thereof shall have been made and (2) such contest would not reasonably be expected to result in a Material Adverse Effect.

Accounting and Financial Management

Each of the Issuer and the Guarantors shall (1) maintain adequate management information and (2) maintain a system of accounting of all financial transactions and the assets and business of such Person in accordance with IFRS. In the event that any of the Issuer or the Guarantors replaces its existing auditors for any reason, such Person shall appoint and maintain as auditors another firm of independent public accountants, which firm shall be internationally recognized.

Reports

So long as any Notes are outstanding, the Issuer will furnish to the noteholders and the Trustee:

(i) as soon as available and in any event within 60 days after the end of the first three fiscal quarters of each fiscal year of the Issuer, a copy of the complete unaudited, condensed consolidated statements of income, retained earnings and cash flow of the Issuer and the Guarantors, and the related unaudited, consolidated balance sheet of the Issuer and the Guarantors as at the end of such period, setting forth in each case in comparative form the corresponding figures for the corresponding period in the preceding fiscal year, if any, prepared in accordance with IFRS and otherwise in a form substantially similar to the financial statements included in this offering memorandum (excluding footnotes and an opinion of the auditors) and presented in the English language, accompanied by a certificate of a Responsible Officer of the Issuer, which certificate shall state that said financial statements fairly present the financial condition and results of operations of the Issuer and the Guarantors in accordance with IFRS, consistently applied, as at the end of, and for, such periods (subject to normal year-end audit adjustments);

(ii) as soon as available and in any event within 120 days after the end of each fiscal year of the Issuer, a copy of the complete audited, consolidated statements of income, retained earnings and cash flow of the Issuer and the Guarantors, and the related audited, consolidated balance sheet of the Issuer and the Guarantors as at the end of such year prepared in accordance with IFRS and any related audit letter, setting forth in each case in comparative form the corresponding figures for the preceding fiscal year, and accompanied by an opinion thereon of a firm of independent certified public accountants of recognized international standing prepared in a form substantially similar to the financial statements included in this offering memorandum and in accordance with IFRS and presented in the English language;

(iii) at the time it furnishes each set of financial statements as described in paragraph (2) above, a certificate of a Responsible Officer of the Issuer stating that: (i) to the best of such person's knowledge, no Default has occurred and is continuing (or, if any Default has occurred and is continuing, describing the same in reasonable detail and describing what action the Issuer has taken and proposes to take with respect thereto) and; (ii) there has been no notice, demand or other communication given or received by the Issuer (A) pursuant to or relating to any of the Transaction Documents (including all requests for amendments or waivers) or pursuant to or relating to any Governmental Approval or (B) to or from any Governmental Authority relating in any way to the Projects; in each case identifying matters which would reasonably be expected to result in a Material Adverse Effect, or except as detailed in such certificate; and

(iv) promptly after any officer or director of the Issuer or any Guarantor knows that any Default or any material default by any Project Party under any Material Project Document has occurred, a written notice of such event describing the same in detail and, together with such notice, a description of what action if the Issuer or any such Guarantor or, if known by the Issuer or such Guarantor, such Project Party has taken and/or proposes to take with respect thereto.

The Issuer will also, for so long as any Notes remain outstanding, furnish or cause to be furnished to the noteholders and prospective investors the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

Additional Covenants

We will also be required to, among other things:

- deliver to the Trustee, not less than 30 days before the commencement of each fiscal year following the Issue Date, an Annual Budget in respect of the immediately succeeding fiscal year together with a certificate of a Responsible Officer certifying that such Annual Budget complies with the requirements of the Indenture; *provided*, *however*, that the failure by the Issuer and the Guarantors to comply with the limits included in the Annual Budget in respect of such fiscal year shall not constitute a Default or an Event of Default;

- deliver to the Trustee, not less than 30 days after the end of (i) each fiscal year following the Issue Date and (ii) each second fiscal quarter following the Issue Date, an Operating Report in respect of the immediately preceding two fiscal quarters;

- duly and punctually pay the scheduled principal of, premium (if any), interest on, Additional Amounts and fees and other amounts in respect of the Notes and the other Indenture Documents to which we are a party;

- comply with all notice requirements contemplated in the Indenture Documents; and

- use commercially reasonable efforts to obtain or maintain ratings from at least two Ratings Agencies; *provided*, *however*, that, in the event that one or more Rating Agency (i) ceases to exist, (ii) ceases to issue ratings of the type issued in respect of the Notes as of the Issue Date or (iii) refuses or otherwise declines to provide a rating for the Notes other than due to the Issuer's failure to (a) provide such Rating Agency with such reports and other information or documents as it shall reasonably request to monitor and affirm the ratings assigned by it to the Notes, (b) pay customary fees to such Rating Agency in connection therewith or (c) take any other action reasonably requested by such Rating Agency in connection therewith (and, in each case of (i) through (iii) above, the Issuer is unable, using commercially reasonable efforts, to substitute such Ratings Agency), the failure by the Issuer to obtain or maintain such rating shall not constitute a Default or Event of Default; *it being understood* that the Issuer shall not request any Rating Agency to cease rating the Notes without the consent of the noteholders (as provided under the caption "*—Amendment, Supplement and Waiver*") and *it being further understood* that the Issuer is not required to obtain or maintain any particular minimum rating of the Notes.

The affirmative and negative covenants described above are subject to a number of additional qualifications and exceptions which are set forth more fully in the Indenture.

The Trustee shall have no duty to review or analyze reports or budgets delivered to it. Delivery of such reports, information and documents to the Trustee is for informational purposes only, and the Trustee's receipt thereof shall not constitute actual or constructive notice of any information contained therein or determinable from information contained therein, including the Issuer's compliance with any of its covenants under the Indenture (as to which the Trustee is entitled to certificates). The Trustee shall not be obligated to monitor or confirm, on a continuing basis or otherwise, the Issuer's compliance with the covenants or with respect to any reports or other documents filed with any website, or participate in any conference calls.

Events of Default and Remedies

Each of the following events is an event of default under the Indenture (an "*Event of Default*"):

(i) failure to pay interest on any Note when the same becomes due and payable and such Default continues uncured for five or more Business Days;

(ii) failure to pay principal, Additional Amounts, if any, or premium, if any, on the Notes as and when the same becomes due and payable, whether at Stated Maturity, upon redemption, upon required repurchase or prepayment by declaration, acceleration or otherwise;

(iii) failure by the Issuer or any Guarantor to perform or observe in any material respect any covenant or agreement contained in the Indenture Documents (other than as described in the clause (i) or (ii) above) and such Default continues uncured for 30 or more days after a Responsible Officer of the Issuer obtains actual knowledge of such failure; *provided*, *however*, that with respect to a Default pursuant to any of the covenants described under the captions "*Inspection*," "*Governmental Approvals*," "*Project Maintenance*," "*Compliance with Laws*," "*Payment of Taxes, etc.*," "*Reports*" and "*Maintenance of Ratings*" in the Indenture, if the Issuer or such Guarantor commences and diligently pursues efforts to cure such Default within such 30-day period, it may continue to diligently pursue such cure of the Default (and such Default will not be deemed an Event of Default) for an additional 30 days;

(iv) any representation, warranty, certification or other statement made by the Issuer or any Guarantor in any (or pursuant to any) Indenture Document proves to have been incorrect in any material respect as of the time made, and the fact, event or circumstance that gave rise to the misrepresentation has resulted in or would reasonably expected to result in a Material Adverse Effect and such misrepresentation or such Material Adverse Effect continues uncured for 30 or more days from the earlier of (A) the date a Responsible Officer of the Issuer obtains actual knowledge thereof and (B) notice from the Trustee or the Majority Holders (with a copy to the Trustee); *provided* that if the Issuer commences and diligently pursues efforts to cure such misrepresentation within such initial 30-day period, it may continue to diligently pursue such cure of the misrepresentation (and such Default will not be deemed an Event of Default) for an additional 60 days;

(v) default (after the expiration of any applicable cure period) under any mortgage, indenture, agreement or instrument under which there is issued or by which there is secured or evidenced any Indebtedness for money borrowed by the Issuer or any Guarantor (or the payment of which is guaranteed by the Issuer or such Guarantor), whether such Indebtedness or guarantee now exists, or is created after the date of the Indenture, if in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a default, aggregates to (or has net mark-to-market exposure of) US$5.0 million or more;

(vi) any Insolvency Proceeding occurs with respect to the Issuer or any of the Guarantors;

(vii) one or more final judgments, decrees or orders of any court, tribunal, arbitration, administrative or other governmental body or similar entity, which is not subject to appeal, for the payment of money is rendered against the Issuer or any Guarantor or any of their respective Properties in an aggregate amount in excess of US$5.0 million (excluding the amount thereof covered by insurance or a performance or similar bond) and such judgment, decree or order remains unvacated, undischarged and unstayed for more than 60 days, except while being contested in good faith by appropriate proceedings;

(viii) any Security Document or similar agreement in favor of the relevant Collateral Agent ceases to be effective to grant a perfected first priority Lien on the Collateral for the benefit of the noteholders, except as otherwise permitted under the Indenture or the Security Documents;

(ix) except as could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect (including as a result of a replacement thereof) (A) any provision of any Material Project Document, at any time after its execution and delivery and for any reason other than as expressly permitted hereunder or thereunder, ceases to be in full force and effect unless the same is being contested by the Issuer or any of the Guarantors that is party thereto; (B) the Issuer or any of the Guarantors contests in any manner the validity or enforceability of any provision of any Material Project Document; or (C) the Issuer or any of the Guarantors denies that it has any or further liability or obligation under any Material Project Document, or purports to revoke, terminate, suspend or rescind any Material Project Document;

(x) except as could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect (including as a result of a replacement thereof) (A) any Material Project Document is terminated, rescinded, cancelled or suspended in advance of its expiration unless such termination, rescission, cancellation or suspension is being contested by the Issuer or any of the Guarantors, or (B) the Issuer or any of the Guarantors breaches in any respect, or causes the termination, rescission, cancellation or suspension of, any Material Project Document, and such termination described in clauses (A) or (B) shall remain unremedied for sixty (60) Business Days after the earlier of (1) a Responsible Officer of such Person having knowledge of such termination, termination, rescission, cancellation or suspension and (2) written notice thereof has been given to the Issuer by the Trustee, or to the Trustee and the Issuer by the holders of at least 25% in aggregate principal amount of the Notes then outstanding;

(xi) an uninsured casualty, loss or damage or any condemnation, nationalization or expropriation event occurs unless such events would not reasonably be expected to have a Material Adverse Effect;

(xii) an Event of Abandonment occurs; and

(xiii) any material Governmental Approvals necessary for the execution, delivery and performance of the material obligations under Security Documents shall be terminated or shall not be obtained, maintained, or materially complied with; unless such failure is remedied or waived within thirty (30) days after the Collateral Agent's provision of written notice thereof to the Issuer, or such longer period, not exceeding sixty (60) days after the expiration of the thirty-day (30) period set forth above, as reasonably requested by the Issuer to remedy or waive such failure.

The Events of Default described above are subject to a number of additional qualifications and exceptions which are set forth more fully in the Indenture.

In the case of an Event of Default arising from certain events of bankruptcy or insolvency, other than during the period in which the *Protección Financiera Concursal* described in Article 57 of Chilean Law No. 20,720 is in effect with respect to any of the Issuer or the Obligors, all outstanding Notes will become immediately due and payable without further action or notice. If an Event of Default occurs and is continuing arising from a failure to pay principal of, premium or Additional Amounts, if any, or interest on the Notes, holders of at least 25% in aggregate principal amount of the then outstanding Notes may declare the Notes to be immediately due and payable. Subject to certain limitations, in the case of any other Event of Default, the Majority Holders may declare the Notes to be immediately due and payable and may instruct the relevant Collateral Agent to enforce the Collateral.

The Trustee will be under no obligation to exercise any of the rights or powers under the Indenture at the request or direction of any noteholders unless such holders have offered to the Trustee reasonable indemnity or security satisfactory to it against any loss, liability or expense. Except (subject to the provisions described under "—*Amendment, Supplement and Waiver*") to enforce the right to receive payment of principal, premium, if any, or interest or Additional Amounts when due, no holder of a Note may pursue any remedy with respect to the Indenture or the Notes unless:

- the noteholder has previously given to a responsible officer of the Trustee written notice of the occurrence and continuance of an Event of Default;
- noteholders holding: (i) in the case of an Event of Default arising from a failure to pay principal of, premium or Additional Amounts (if any) or interest on the Notes, at least 25% in aggregate principal amount of the then outstanding Notes or (ii) in the case of any other Event of Default, the Majority Holders, have made a written request to a responsible officer of the Trustee to institute the suit, action or proceeding and shall have offered and provided to the Trustee security or indemnity satisfactory to it;
- the Trustee has refused or neglected to institute the suit, action or proceeding within 60 days after the receipt by a responsible officer of the Trustee of the notice, request and offer and provisions of the security or indemnity; and
- no direction inconsistent with such written request has been given to the Trustee during the 60-day period by the Majority Holders.

The Majority Holders by written notice to the Issuer and to the Trustee may rescind and annul a declaration of acceleration and its consequences if:

(i) all existing Events of Default, other than the nonpayment of the principal of, premium, if any, and interest on the Notes that have become due solely by the declaration of acceleration, have been cured or waived, and

(ii) the rescission would not conflict with any judgment or decree of a court of competent jurisdiction.

The Majority Holders may on behalf of the holders of all Notes waive any past Default or an Event of Default and its consequences, except that only the noteholders affected thereby may waive a Default or Event of Default (1) in the payment of the principal of and interest on, Additional Amounts or other amounts due under, such outstanding Note; and (2) in respect of a covenant or provision that under the Indenture cannot be modified or amended without the consent of each affected noteholder.

If any Event of Default occurs and is continuing and is actually known to a responsible officer of the Trustee, the Trustee will send notice of the Event of Default to each noteholder within 90 days after it obtains knowledge thereof, unless the Event of Default has been cured; provided that, except in the case of a default in the payment of the principal of or interest on any Note, the Trustee may withhold the notice if and so long as the Trustee in good faith determine that withholding the notice is in the interest of the noteholders.

Noteholders may not enforce the Collateral, except as provided in the Security Documents.

No Personal Liability of Directors, Officers, Employees, Partners and Shareholders

No director, officer, employee, incorporator, partner or shareholder of the Issuer or any Guarantor, as such, will have any liability for any obligations of the Issuer or the Guarantors under the Notes, the Indenture, the Note Guarantees, the Security Documents or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each noteholder by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. The waiver may not be effective to waive liabilities under the federal securities laws.

Defeasance

We may, at any time, terminate all of our obligations (other than those obligations which by their terms survive) under the Indenture, the Notes and the other Indenture Documents, and may terminate the Liens of the Security Documents on the Collateral (a "*Legal Defeasance*"). In addition, we may terminate, at any time, all of our obligations (other than those obligations which by their terms survive) under any of the covenants under the Indenture, the Notes and the other Indenture Documents, and may terminate the Liens of the Security Documents on the Collateral, other than our covenants to maintain our existence and to make payments on the Notes out of the trusts described below (a "*Covenant Defeasance*").

Each of the Legal Defeasance or the Covenant Defeasance may be exercised only if the following conditions are met:

- we must irrevocably deposit with the Trustee, in trust, for the benefit of the noteholders, cash in U.S. dollars, non-callable U.S. Government Obligations, or a combination of cash in U.S. dollars and non-callable U.S. Government Obligations, in amounts as will be sufficient without reinvestment, in the opinion of a nationally recognized investment bank, appraisal firm or firm of independent public accountants (provided, that no opinion from a nationally recognized investment bank, appraisal firm or firm of independent public accountants will be needed if such deposit consists solely in cash), to pay the principal of, or interest and premium (if any) and Additional Amounts (if any), on the outstanding Notes on the stated date for payment thereof or on the applicable redemption date, as the case may be, and we must specify whether the Notes are being defeased to such stated date for payment or to a particular redemption date;

- no Default or Event of Default has occurred and is continuing on the date of such deposit or will result from such deposit (other than from the incurrence of Indebtedness the proceeds of which will be used for the Legal Defeasance or the Covenant Defeasance, as the case may be);

- in the case of a Legal Defeasance, we have delivered to the Trustee an Opinion of Counsel reasonably acceptable to the Trustee confirming that (a) we have received from, or there has been published by, the Internal Revenue Service a ruling or (b) since the date of the Indenture there has been a change in the applicable U.S. federal income tax law, in either case to the effect that, and based thereon such Opinion of Counsel will confirm that, the holders will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Legal Defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

- in the case of a Covenant Defeasance, we must deliver to the Trustee an Opinion of Counsel reasonably acceptable to the Trustee confirming that the noteholders will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Covenant Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

- such Legal Defeasance or Covenant Defeasance will not result in a breach or violation of, or constitute a default under, any material agreement or instrument (other than the Indenture Documents) to which we are a party or by which we are bound;

- we must deliver to the Trustee a certificate of a Responsible Officer stating that the deposit was not made by us with the intent of preferring the noteholders over any of our other creditors with the intent of defeating, hindering, delaying or defrauding any of our creditors or others; and

- we must deliver to the Trustee a certificate of a Responsible Officer and an Opinion of Counsel, each stating that all conditions precedent relating to the Legal Defeasance or the Covenant Defeasance have been complied with.

Satisfaction and Discharge

The Indenture will upon written request by us be discharged and will cease to be of further effect, and the Trustee shall execute instruments acknowledging satisfaction and discharge of the Indenture, when either:

- all Notes and Additional Notes issued under the Indenture theretofore authenticated and delivered (other than (1) Notes and Additional Notes which have been destroyed, lost or stolen and which have been replaced or paid as provided in the Indenture and (2) Notes and Additional Notes for whose payment money has been deposited in trust or segregated and held in trust by us and thereafter repaid to us or discharged from such trust, as provided in the Indenture) have been delivered to the Trustee for cancellation; or

- all such Notes and Additional Notes not theretofore delivered to the Trustee for cancellation (1) have become due and payable, (2) will become due and payable at their Stated Maturity within one year, or (3) are to be called for redemption within one year under arrangements provided in the Indenture, and we in the case of (1), (2) or (3) described in this bullet, have deposited or caused to be deposited with the Trustee in trust for such purpose money (in the form of cash in U.S. dollars or U.S. Government Obligations, or a combination thereof) in an amount sufficient without reinvestment, in the written opinion of an internationally recognized accounting firm, to pay and discharge the entire Indebtedness on such Notes and Additional Notes, for principal and any premium and interest to the date of maturity or redemption;

- we have paid or caused to be paid all other sums payable thereunder by us;

- no Default or Event of Default has occurred and is continuing on the date of the deposit (other than a Default or Event of Default resulting from the borrowing of funds to be applied to such deposit) and the deposit will not result in a breach or violation of or constitute a default under, any other instrument to which the Issuer is a party or by which the Issuer is bound;

- we have delivered irrevocable instructions to the Trustee under the Indenture to apply the deposited money toward the payment of the Notes at maturity or on the redemption date, as the case may be; and

- we have delivered to the Trustee a certificate of a Responsible Officer and an Opinion of Counsel, each stating that all conditions precedent provided in the Indenture with respect to the satisfaction and discharge of the Indenture have been satisfied.

Amendment, Supplement and Waiver

We and the Trustee (and/or any relevant Security Agent party to such Indenture Document), may amend or supplement the Indenture Documents (or provide the Security Agent with any necessary direction) without the consent of the holders for certain specified purposes, including, among others, for any of the following purposes:

- to establish the form and terms of the Notes of any series permitted by the Indenture;

- to provide for the issuance of Additional Notes in accordance with the Indenture;

- to add to our covenants or to surrender any right or power conferred in the Indenture upon us;

- to convey, transfer and assign Properties or assets to the Trustee to secure the Senior Secured Obligations, to correct or amplify the description of any Property at any time subject to the Lien of any Security Document, to perform any amendments that are ministerial in nature not negatively affecting the rights of holders or to assure, convey and confirm unto the relevant Security Agent, any Property subject to or required to be subject to the Lien of the Security Documents;

- to evidence the release of any Note Guarantee in accordance with the terms of the Indenture, including in connection with a merger of any Guarantor with or into the Issuer or another Guarantor as part of any internal reorganization permitted under the Indenture or a Transfer permitted under the Indenture;

- to evidence the release of any Collateral in accordance with the Indenture or the Security Documents, including in connection with a merger of any Guarantor with or into the Issuer or another Guarantor as part of any internal reorganization permitted under the Indenture or a Transfer permitted under the Indenture;

- in connection with and to reflect any amendments to the provisions of the Indenture required by any Rating Agency in circumstances in which a Ratings Affirmation is required pursuant to the Indenture; *provided*, *however*, such amendments could not prejudice the noteholders or the Trustee;

- (a) to add a Guarantor, (b) to provide for the assumption of a Guarantor's obligations under the Indenture in connection with a merger of any Guarantor with or into the Issuer or another Guarantor as part of any internal reorganization permitted under the Indenture or a Transfer permitted under the Indenture, or (c) to add any Collateral under the Indenture;

- to make any other change that does not materially and adversely affect the rights hereunder of any noteholder or to conform the text of this Indenture to any provision of the "*Description of the Notes*" section of this offering memorandum;

- to comply with any applicable rules or regulations of the SEC or any securities exchange on which the Notes issued under the Indenture may be listed;

- to evidence the appointment of a successor Security Agent;

- to comply with the requirements of the SGX, DTC Euroclear or Clearstream or any successor clearing system for the Notes; and

- to cure any ambiguity, to correct or supplement any provision in any Indenture Document that may be defective or inconsistent with any other provision in such Indenture Document, to establish any other provisions with respect to matters or questions arising under any Indenture Document or to make any other modification to any Indenture Document, *provided*, that such action shall not adversely affect the interests of the noteholders of any series in any material respect.

With the consent of the Majority Holders on behalf of the holders of all Notes, we and the Trustee (and/or any relevant Security Agent party to such Indenture Document) may amend or supplement the Indenture or any other Indenture Document (or provide the Security Agent with any necessary direction) for the purpose of adding any provisions to or changing in any manner or eliminating any of the provisions of the Indenture or any other Indenture Document or of modifying in any manner the rights of the noteholders of such series issued thereunder; *provided*, *however*, that no such supplemental indenture or amendment to another Indenture Document shall, without the consent of the affected noteholders:

- change any Note Payment Date of any Note or change the principal amount thereof or the interest thereon, or premium paid in connection therewith, or change the place of payment where, or the coin or currency in which, any Note or the interest thereon is payable, or impair the right to receive any principal payment on such Note, on or after the Stated Maturity thereof, or to institute suit for the enforcement of any such payment; or

- except to the extent expressly permitted by the Indenture or such other Indenture Document, permit the creation of any Lien prior to or pari passu with the Lien of the Security Documents with respect to any of the Collateral, terminate (except as specifically contemplated by the Indenture) the Lien of or deprive any noteholder of the security afforded by the Lien of the Security Documents; or

- modify the amendment section of the Indenture requiring consent of noteholders, reduce the percentage in principal amount of the outstanding Notes the consent of whose noteholders is required for any supplemental indenture or amendment to such other Indenture Document, or the consent of whose noteholders is required for any waiver (of compliance with certain provisions of the Indenture or certain Defaults under the Indenture and their consequences or provisions of the other Indenture Documents) provided for in the Indenture or such other Indenture Document; or

- reduce the amount payable upon the redemption of any Note or the times at which any Note may be redeemed or, once notice of redemption has been given, the time at which it must thereupon be redeemed;

- modify or change any provision of the Indenture affecting the ranking of the Notes or the Note Guarantees by the Guarantors in a manner adverse to such noteholder; or

- after the time an Offer to Purchase is required to have been made, reduce the purchase amount or purchase price, or extend the latest expiration date or purchase date thereunder; or

- request that any Rating Agency cease rating the Notes.

A supplemental indenture or amendment that changes or eliminates any covenant or other provision of the Indenture or any other Indenture Document which has expressly been included solely for the benefit of one or more particular series of Notes issued thereunder, or which modifies the rights of the noteholders of such series with respect to such covenant or other provision, shall be deemed not to affect the rights under the Indenture or such other Indenture Document of the noteholders of any other series.

It is not necessary for noteholders to approve the particular form of any proposed amendment, supplement or waiver, but is sufficient if their consent approves the substance thereof.

None of the Issuer or the Guarantors nor any of their respective Subsidiaries or Affiliates may, directly or indirectly, pay or cause to be paid any consideration, whether by way of interest, fee or otherwise, to any noteholder for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes unless such consideration is offered to be paid or agreed to be paid to all noteholders that consent, waive or agree to amend such term or provision within the time period set forth in the solicitation documents relating to the consent, waiver or amendment.

In addition, any amendment to, or waiver of, the provisions of the Indenture or any Security Document that has the effect of releasing all or substantially all of the Collateral from the Liens securing the Notes will require the consent of the noteholders of at least 75% in aggregate principal amount of the Notes then outstanding; provided, however, that all Collateral shall be released from the Liens securing the Notes without noteholders consent upon the discharge of the Issuer's and the Guarantor's obligations under the Notes and the Note Guarantees through the redemption of all of the Notes outstanding or payment in full of the obligations under the Indenture Documents.

Prior to the execution of any such modification (or any requisite direction from the Trustee as may be necessary), each of the Trustee and any applicable Security Agent will be entitled to receive and rely upon an Opinion of Counsel and an Officer's Certificate stating that the execution of such amendment (or direction) is authorized and permitted by the Indenture and any applicable Indenture Document and that all conditions precedent under the Indenture and any applicable Indenture Document have been complied with.

Concerning the Trustee

Citibank, N.A. is the Trustee under the Indenture.

Except during the continuance of an Event of Default, the Trustee need perform only those duties that are specifically set forth in the Indenture and no others, and no implied covenants or obligations will be read into the Indenture against the Trustee. In case an Event of Default has occurred and is continuing, the Trustee shall exercise those rights and powers vested in it by the Indenture, and use the same degree of care and skill in their exercise, as a prudent Person would exercise or use under the circumstances in the conduct of such Person's own affairs. No provision of the Indenture will require the Trustee to expend or risk its own funds or otherwise incur any financial liability in the performance of its duties thereunder, or in the exercise of its rights or powers, unless it receives indemnity or security satisfactory to it against any loss, liability or expense.

The Trustee is permitted to engage in other transactions with the Guarantors and its Affiliates; provided that if it acquires any conflicting interest it must either eliminate the conflict within 90 days or resign as Trustee (which such resignation shall become effective until a successor trustee has been appointed and has accepted the mandate).

Paying Agent

The Trustee will initially act as the paying agent and registrar for the Notes. The Issuer may appoint other paying agents and registrars instead of, or in addition to, the Trustee. For so long as the Notes are listed on the SGX and the rules of the SGX so require, the Issuer shall appoint and maintain a paying agent in Singapore, where the Notes may be presented or surrendered for payment or redemption, in the event that the global Notes are exchanged for definitive certificated Notes.

Notices

For so long as Notes in global form are outstanding, notices to be given to noteholders will be given to the Depositary, in accordance with its applicable policies as in effect from time to time. If the Issuer issues Notes in certificated form, notices to be given to noteholders will be sent by mail to the respective addresses of the noteholders as they appear in the registrar's records, and will be deemed given when mailed. For so long as the Notes are listed on the SGX, the Issuer will publish notices in the manner required by the SGX. Notices shall be deemed to have been given on the first date of publication. Neither the failure to give any notice to a particular noteholder, nor any defect in a notice given to a particular noteholder, will affect the sufficiency of any notice given to another noteholder.

Governing Law

The Indenture, the Notes, the Note Guarantees, the Security and Depositary Agreement and certain other transaction documents shall be governed by, and construed in accordance with, the laws of the State of New York. The other Security Documents will be governed by Chilean law.

Consent to Jurisdiction

The parties to each of the Indenture, any Note, the Note Guarantees and any other document governed by the laws of New York in relation to the offering of the Notes, will (and each noteholder by their acceptance of the notes will be deemed to) irrevocably waive any right to a trial by jury and submit to the jurisdiction of any New York State or United States Federal court sitting in the City of New York, New York County over any suit, action or proceeding arising out of or relating thereto. Each of such Persons will irrevocably waive, to the fullest extent permitted by Applicable Law, any objection which it may now or hereafter have to the laying of venue of any such suit, action or proceeding brought in such courts and any claim that any such suit, action or proceeding brought in such courts, has been brought in an inconvenient forum and any right to any other jurisdiction which it may be entitled on account of place of residence or domicile. To the extent the Issuer or a Guarantor has or hereafter may acquire any immunity from jurisdiction of any court or from any legal process with respect to itself or its property, each of the Issuer and the Guarantors have irrevocably waived such immunity in respect of (1) its obligations under the Indenture and (2) any Note or the Note Guarantees. Each of the Issuer and the Guarantors will agree that final judgment in any such suit, action or proceeding brought in such a court shall be conclusive and binding on them and may be enforced in any court to the jurisdiction of which each of them is subject by a suit upon such judgment, provided, that service of process is effected upon the Issuer or the Guarantors in the manner specified in the following paragraph or as otherwise permitted by Applicable Law.

As long as any of the Notes remain outstanding, the Issuer and the Guarantors will at all times have an authorized agent in the City of New York, upon whom process may be served in any legal action or proceeding arising out of or relating to the Indenture or any Note or the Note Guarantees. Service of process upon such agent and written notice of such service mailed or delivered to the Issuer or the Guarantors shall to the extent permitted by Applicable Law be deemed in every respect effective service of process upon the Issuer or such Guarantor, as the case may be, in any such legal action or proceeding. The Issuer and the Guarantors will appoint Corporation Service Company as their agent for such purpose and, in the case of the Issuer and any of the Guarantors, shall grant an irrevocable power of attorney in favor of such process agent with sufficient authority for lawsuits and collections. The Issuer and Guarantors further covenant and agree that service of process in any suit, action or proceeding may be made upon it at the office of such agent at 19 West 44th Street, Suite 200, New York, New York 10036-8401, United States of America (or at such other address or at the office of such other authorized agent as the Issuer or the Guarantors may designate by written notice to the Trustee).

Judgment Currency

U.S. dollars are the sole currency of account and payment for all sums due and payable by the Issuer and the Guarantors under the Indenture, the Notes and the Note Guarantees. If, for the purpose of obtaining judgment in any court, it is necessary to convert a sum due hereunder in U.S. dollars into another currency, the Issuer and the Guarantors will agree, to the fullest extent that they may legally and effectively do so, that the rate of exchange used shall be that at which in accordance with normal banking procedures the Trustee determines a Person could purchase U.S. dollars with such other currency in New York, New York, on the Business Day immediately preceding the day on which final judgment is given.

The obligation of each of the Issuer and the Guarantors in respect of any sum due to any noteholder or the Trustee in U.S. dollars shall, to the extent permitted by Applicable Law, notwithstanding any judgment in a currency other than U.S. dollars, be discharged only to the extent that on the Business Day following receipt of any sum adjudged to be so due in the judgment currency such noteholder or Trustee may in accordance with normal banking procedures purchase U.S. dollars in the amount originally due to such Person with the judgment currency. If the amount of U.S. dollars so purchased is less than the sum originally due to such Person, each of the Issuer and the Guarantors agrees, jointly and severally, as a separate obligation and notwithstanding any such judgment, to indemnify such Person against the resulting loss; and if the amount of U.S. dollars so purchased is greater than the sum originally due to such Person, such Person will, by accepting a Note, be deemed to have agreed to repay such excess.

Statute of Limitations

Claims under New York state law against the Issuer or any Guarantor for the payment of principal, interest or Additional Amounts will expire six years after the applicable due date for payment thereof.

Certain Definitions

"*Acceptable Issuer*" has the meaning set forth under the caption "—*LC Facility Agreement*."

"*Acceptable LC*" shall mean a letter of credit meeting the following requirements:

(a) such letter of credit is written in the English language and is drawable in New York, New York;

(b) such letter of credit shall be issued by an Acceptable Issuer in favor of the Offshore Collateral Agent (for the benefit of the Secured Parties);

(c) amounts available under such letter of credit may be drawn on demand, without presentation of any document other than a drawing certificate and copies of the letter of credit, at any time from time to time in whole or in part from the issue date thereof until the expiration thereof;

(d) (i) such letter of credit is issued for a term of at least one (1) year and provides that upon any stated expiration date thereof it shall automatically renew for an additional one (1) year term unless, at least thirty (30) days prior to the then-scheduled expiration date, the issuer thereof notifies the Offshore Collateral Agent that the letter of credit will not be renewed and (ii) if the Issuer has not replaced such letter of credit at least fifteen (15) days prior to the expiration of such letter of credit as required pursuant to the Security and Depositary Agreement, the Offshore Collateral Agent shall be entitled to draw all amounts then available thereunder at any time prior to its expiration;

(e) if the issuer of such letter of credit ceases to be an Acceptable Issuer, and the Issuer has not replaced such letter of credit as required pursuant to the Security and Depositary Agreement, the Offshore Collateral Agent shall be entitled to draw all amounts then available thereunder;

(f) such letter of credit shall be subject to International Standby Practices 1998 (ISP 98) as set out in International Chamber of Commerce Publication No. 590, as amended, modified or supplemented and in effect from time to time and, to the extent not inconsistent therewith, governed by and construed in accordance with the law of the State of New York; and

(g) either, (i) such letter of credit is issued under the LC Facility Agreement, or (ii) none of the Issuer and the Guarantors is the account party in respect of such letter of credit or otherwise liable in any respect of any reimbursement, payments for any drawings under such letter of credit or any other costs associated therewith.

"*Additional Amounts*" has the meaning set forth under the caption "—*Additional Amounts*."

"*Additional Material Project Document*" means any contract or agreement relating to the operation, maintenance, repair, financing or use of the Projects entered into by the Issuer or any Guarantor with any other Person subsequent to the date of this offering (including any contract(s) or agreement(s) entered into in substitution for any Material Project Document that has been terminated in accordance with its terms or otherwise); which, for the avoidance of doubt, shall include any Non-Material Project Document that may become a Material Project Document pursuant to its terms.

"*Additional Notes*" has the meaning set forth under the caption "—*Issuance of Additional Notes*."

"*Administrative Agent*" has the meaning set forth under the caption "—*LC Facility Agreement*."

"*Affiliate*" means, with respect to any Person, any other Person directly or indirectly controlling, controlled by, or under common control with, such Person. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with") with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of Voting Stock, by contract or otherwise.

"*Annual Budget*" means an annual budget, prepared in good faith by the Issuer using reasonable assumptions, setting forth in reasonable detail for each fiscal year: (i) the amount of the Issuer's projected O&M Costs (other than capital expenditures) for each month of such fiscal year and (ii) the amount of the Issuer's projected capital expenditures for such fiscal year, in each case, taking into account the Material Project Documents, Non-Material Project Documents, and existing or reasonably expected economic, regulatory and market environments (including spot market prices), in each case as determined solely by the Issuer; provided, that if the projected O&M Costs or projected capital expenditures for a fiscal year exceed 110% of the applicable amount in the Base Case Model, such amount shall be approved by the Independent Engineer.

"*Applicable Law*" means any constitution, statute, law, rule, regulation, ordinance, judgment, order or any decree, directive or requirement which has the force of law, or other governmental restriction which has the force of law, or any determination by, or interpretation of any of the foregoing by, any judicial authority, applicable to and/or binding on a given Person or the Projects, as the context may require, whether in effect as of the Issue Date or thereafter and in each case as amended (including, without limitation, all Environmental Laws and any of the foregoing pertaining to land use or zoning restrictions).

"*ATOP*" has the meaning set forth under the caption "—*Intercreditor Arrangements—Voting*."

"*Available Cash*" means, as of any date of determination, any amount standing to the credit of the Revenue Accounts after the application of amounts set out in priorities *first* through *seventh* in the accounts waterfall described in section "—*Revenue Accounts*."

"*Base Case Model*" means the financial model for the Project prepared and delivered in electronic form to the Trustee on or prior to the Issue Date.

"*Business Day*" means any day that is not a day on which banks are required or authorized to close in the City of New York or Santiago de Chile.

"*Capital Stock*" means, with respect to any Person, any and all shares, interests, participations and/or rights in or other equivalents (however designated, whether voting or nonvoting, ordinary or preferred) in the equity or capital of such Person, now or hereafter outstanding, and any and all rights, warrants or options exchangeable for or convertible into any thereof.

"*Capitalized Lease Obligations*" means an obligation that is required to be classified and accounted for as a capitalized lease for financial reporting purposes in accordance with IFRS and the amount of Indebtedness represented by such obligation shall be the capitalized amount of such obligation determined in accordance with IFRS.

"*Cash Available for Debt Service*" means, for any period, the difference between the (a) Project Revenues for such period and (b) O&M Costs for such period and fees, expenses and indemnities payable to the Trustee, any Security Agent and any other agent of the Secured Parties for such period all as computed on a cash basis (including counsel expenses).

"*Cash Equivalents*" means:

(i) money;

(ii) securities issued or fully guaranteed or insured by the United States of America, Japan, Switzerland, Canada, Chile or a member state of the European Union or any agency or instrumentality of any thereof which are not callable or redeemable at the Issuer's option;

(iii) overnight bank deposits, time deposits, certificates of deposit or bankers' acceptances of any commercial bank having capital and surplus in excess of US$500.0 million (or the foreign currency equivalent thereof as of the date of such investment) and the commercial paper of the holding company of which is rated at least A-2 or the equivalent thereof by S&P or at least P-2 or the equivalent thereof by Moody's (or if at such time neither is issuing ratings, then a comparable rating of another nationally recognized rating agency);

(iv) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (2) and (3) above entered into with any financial institution meeting the qualification specified in clause (3) above but with respect to underlying securities issued or fully guaranteed or insured by the United States government such repurchase obligations may have a term of not more than 30 days;

(v) money market instruments, commercial paper or other short-term obligations rated at least A-1 or the equivalent thereof by S&P or at least P-1 or the equivalent thereof by Moody's (or if at such time neither is issuing ratings, then a comparable rating of another nationally recognized rating agency);

(vi) investments in money market funds subject to the risk limiting conditions of Rule 2a-7 or any successor rule of the U.S. Securities Exchange Commission under the Investment Company Act of 1940, as amended; and

(vii) investments similar to and, to the extent applicable, with the same credit ratings as any of the foregoing denominated in foreign currencies approved by the board of directors of the Issuer.

"*Casualty Event*" means, with respect to any Project or the property, assets, business or operations of the Issuer or any of the Guarantors, the destruction, damage, impairment or loss of use of any such Project or any such property or assets in their entirety or such a material portion thereof that the then remaining portion of such Project or such property or assets cannot practically be used in accordance with Applicable Laws and Prudent Industry Practices and for its intended purpose in accordance with the Material Project Documents. The date of occurrence of any Casualty Event will be the date of the casualty or other occurrence specified above giving rise to such Casualty Event.

"*Casualty Proceeds*" means all insurance proceeds or other amounts actually received on account of a Casualty Event, except proceeds of business interruption insurance.

"*Change of Control*" means (A) Permitted Holders shall cease to beneficially own, at any time, in the aggregate, directly or indirectly, capital stock representing more than 50% of the total voting power of the Issuer; (B) there is a sale, lease or transfer of all or substantially all of the assets of the Issuer and its Subsidiaries, taken as a whole, to any Person other than a Permitted Holder; or (C) the adoption of a plan or resolution relating to the liquidation or dissolution of the Issuer or any other Guarantor; provided, however, that in respect of clauses (A) and (B) above, a "Change of Control" shall not be deemed to have occurred so long as the Issuer has received a Ratings Affirmation.

"*Chilean Security Document*" has the meaning set forth under the caption "*—Collateral*."

"*Collateral*" has the meaning set forth under the caption "*—Collateral*."

"*Collateral Agents*" means, collectively, the Onshore Collateral Agent and the Offshore Collateral Agent.

"*Collateral Proceeds*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Priority of Payments*."

"*Commodity Agreement*" means with respect to any Person any commodity swaps, commodity options or forward commodity contracts or other similar agreement or arrangement as to which such Person is party or a beneficiary.

"*Condemnation Event*" means any compulsory transfer or taking or transfer under threat of compulsory transfer or taking of all or a material part of the Projects (or the Capital Stock of the Issuer) by any Governmental Authority or entity acting under power of eminent domain or similar power or authority.

"*Condemnation Proceeds*" means all eminent domain proceeds, insurance proceeds or other amounts actually received on account of a Condemnation Event.

"*Currency Agreement*" means with respect to any Person any currency swap transactions, cross-currency rate swap transactions, currency options, spot contracts or other similar agreement or arrangement as to which such Person is a party or a beneficiary.

"*Customer Financing*" means Indebtedness owing to a customer of a Guarantor incurred in connection with financing capital improvements related to providing transportation services to such customer, consistent with past practices.

"*Debt Service*" means, for any period, without duplication, the aggregate amount of all interest and regularly scheduled principal payable during such period under the Indenture and the other Indenture Documents and in connection with all other Permitted Indebtedness that is not subordinated Indebtedness, in each case calculated on a cash and not an accrual basis, and with respect to any letters of credit supporting the Debt Service Reserve Account and the O&M Reserve Account the witholding taxes and letter of credit fees due and payable for that period. For the avoidance of doubt, principal payment amounts corresponding to the Target Debt Balance Cash Sweep shall not be considered for the calculation of Debt Service.

"*Debt Service Coverage Ratio*" means, for any period, the ratio of (i) the Cash Available for Debt Service for such period to (ii) Debt Service for such period.

"*Debt Service Coverage Statement*" means a calculation of the Debt Service Coverage Ratio or the Projected Debt Service Coverage Ratio for the relevant period certified by a Responsible Officer of the Issuer together with supporting data in reasonable detail.

"*Debt Service Reserve Account*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*Debt Service Reserve Excess*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*Debtor Relief Laws*" means the Bankruptcy Code of the United States, the Chilean Law 20,720 and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization, or similar debtor relief laws of the United States, Chile or other applicable jurisdictions from time to time in effect and affecting the rights of creditors generally.

"*Decision Period*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*Default*" means any occurrence, circumstance or event, or any combination thereof, which, with the lapse of time and/or the giving of notice, would constitute an Event of Default.

"*Denominator*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*Depositary Banks*" means the Onshore Depositary Bank and the Offshore Depositary Bank.

"*Disposition*" means any direct or indirect sale, lease (other than an operating lease entered into in the ordinary course of business), transfer, issuance or other disposition, or a series of related sales, leases, transfers, issuances or dispositions that are part of a common plan, of shares of Capital Stock of a Subsidiary (other than directors' and employees' qualifying shares), Property or other assets by the Issuer or any of its Subsidiaries, including any disposition by means of a merger, consolidation or similar transaction.

"*Disqualified Stock*" means any Capital Stock that, by its terms (or by the terms of any security into which it is convertible, or for which it is exchangeable, in each case, at the option of the holder of the Capital Stock), or upon the happening of any event, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or redeemable at the option of the holder of the Capital Stock, in whole or in part, on or prior to the date that is 91 days after the Stated Maturity of the Notes.

"*Distribution Holding Account*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*DSRA Requirement*" means, as of any date of determination, an amount necessary to pay projected interest and scheduled principal on the Notes on the immediately following Note Payment Date.

"*Eligible Equity Offering*" means a public or private offering for cash occurring after the Issue Date of Equity Interest (except Disqualified Stock) of the Issuer.

"*Emergency Costs*" means unforeseen O&M Costs incurred by an Obligor on an urgent basis due to the occurrence of any event or circumstance that poses a serious and imminent risk to the integrity of any Property or the health and safety of an Obligor's officers or employees or the release or discharge of any hazardous substance, waste, pollutant or contaminant that may be harmful to human health or the environment, in each case, at a Project Site, in an amount not to exceed $5,000,000 unless otherwise approved by the Independent Engineer.

"*Environmental Laws*" means any law (including common law), statute, code, ordinance, order, determination, rule, regulation or decree of any Governmental Authority, whether now or hereinafter in effect, relating to pollution or protection of the environment or human health and safety (as affected by exposure to hazardous or toxic substances), including any of the foregoing relating to discharges or the clean-up or remediation of hazardous or toxic substances.

"*Equity Interests*" means Capital Stock and all warrants, options or other rights to acquire Capital Stock (but excluding any debt security that is convertible into, or exchangeable for, Capital Stock).

"*Event of Abandonment*" means, with respect to a Project, the suspension or cessation for a period of at least 15 consecutive days of all or substantially all of the operational and maintenance activities at a Project; *provided*, *however*, that any such suspension or cessation that arises from an Event of Loss, a requirement of Applicable Law or Governmental Approval, an event of force majeure, curtailment or failure to be dispatched, or other bona fide business reasons shall not constitute an Event of Abandonment, in each case, so long as the Issuer is taking commercially reasonable actions to overcome or mitigate the effects of the cause of the suspension or cessation so that maintenance and/or operations, as the case may be, can be resumed. Any period of cessation or suspension shall end on the date that work of a substantial nature is resumed and thereafter diligently pursued.

"*Event of Loss*" means a Casualty Event or a Condemnation Event.

"*Event of Loss Proceeds*" means Casualty Proceeds and Condemnation Proceeds.

"*Existing Holders*" means GMR Holding B.V., BTG Pactual Brazil Infrastructure Fund II LP, Patria Infrastructure Fund II LP, Patria Infrastructure Fund II LAP Co-Invest, LP, Patria Infrastructure Fund II LAP Co-Invest, UK LP, PI Fund II (Ontario) LP, PI Fund II (Ontario 1) LP, PI Fund II (Ontario 2) LP and their respective Affiliates.

"*Existing Indebtedness*" means the Indebtedness outstanding on the Issue Date under the Note Purchase and Guarantee Agreement dated as of August 18, 2017, as amended by and among the Issuer, as issuer, San Juan and Norvind, as guarantors, The Bank of New York Mellon, as offshore collateral agent, registrar and paying agent and the purchasers named therein.

"*Fair Market Value*" means, with respect to any Person, the value that would be paid by a willing buyer to an unaffiliated willing seller in a transaction not involving distress or necessity of either party, determined in good faith by the board of directors of such Person.

"*Feasible Repair Certificate*" means, with respect to any Property, or applicable portion thereof, of the Issuer or any of the Guarantors, certificate of a Responsible Officer (a) describing in reasonable detail the nature of the rebuilding, repair or restoration of such Property or portion thereof as a result of the Event of Loss, (b) stating the expected cost of such rebuilding, repair or restoration (including a reasonable contingency), (c) certifying that such Property or portion thereof is reasonably expected to be rebuilt, repaired or restored to permit operation thereof on a commercially feasible basis in accordance in all material respects with all Material Project Documents and relevant Governmental Approvals, (d) certifying that the funds available to the Issuer or any such Guarantors for such rebuilding, repair or restoration (other than proceeds of business interruption insurance) are reasonably expected to be sufficient to permit such rebuilding, repair or restoration and (e) certifying that the Issuer or any such Guarantor shall use its commercially best efforts to cause any repairs or restoration to be commenced and completed promptly and diligently at its own cost and expense.

"*Fitch*" means Fitch Ratings, Inc. or any successor thereto.

"*Governmental Approval*" means any applicable consent, license, approval, registration, filing, permit, authorization, ruling, certification, exemption, variance, order, decree, publication, notice, or declaration by or with (as applicable) any Governmental Authority.

"*Governmental Authority*" means any government, governmental department, ministry, commission, board, bureau, agency, regulatory authority, instrumentality of any government (central or state), judicial, legislative or administrative body, federal, state or local, having jurisdiction over the matter or matters in question.

"*Governmental Rules*" means any statute, law, treaty, regulation, ordinance, rule, judgment, order, decree, permit, concession, grant, franchise, license, agreement, directive, requirement or other governmental restriction or any similar form of decision of or determination by, or any interpretation or administration of any of the foregoing, in each case, having the force of law by, any Governmental Authority, which is applicable to any Person, whether now or hereafter in effect.

"*Ground Lease*" means, with respect to any Project Site that is leased by any Guarantor, the lease or use agreement entered into by such Guarantor for such Project Site.

"*Guarantee*" means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Indebtedness of any other Person and any obligation, direct or indirect, contingent or otherwise, of any Person (1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness of such other Person (whether arising by virtue of partnership arrangements, or by agreement to keep-well, to purchase assets, goods, securities or services, to take-and-pay, or to maintain financial statement conditions or otherwise) or (2) entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part); provided, however, that the term "Guarantee" shall not include endorsements of negotiable instruments for collection or deposit in the ordinary course of business. The term "Guarantee" used as a verb has a correlative meaning.

"*Guarantors*" has the meaning set forth under the caption "—*General*."

"*Hedging Obligations*" of any Person means the obligations of such Person pursuant to any Swap Agreement.

"*IFRS*" means the International Financial Reporting Standards and applicable accounting requirements set by the International Accounting Standards Board or any successor thereto, as in effect from time to time.

"*Indebtedness*" of any Person means, without duplication, (a) all obligations of such Person for borrowed money of any kind; (b) all obligations of such Person evidenced by Notes, debentures or similar instruments; (c) all obligations of such Person under conditional sale or other title retention agreements relating to Property or assets purchased by such Person; (d) all obligations of such Person issued or assumed as the deferred purchase price of Property or services (excluding trade accounts payable arising in the ordinary course of business); (e) all Indebtedness of others secured by (or for which the holder of such Indebtedness has an existing right, contingent or otherwise, to be secured by) any Lien on Property owned or acquired by such Person, whether or not the obligations secured thereby have been assumed, calculated as the lower of the Indebtedness so secured and the Fair Market Value of the Property subject to such Lien; (f) all Guarantees by such Person of Indebtedness of others; (g) all Capitalized Lease Obligations of such Person; (h) all obligations of such Person in respect of Hedging Obligations; and (i) all obligations of such Person as an account party in respect of letters of credit and bankers' acceptances (other than obligations described in clauses (a) through (h) above) entered into in the ordinary course of business of such Person to the extent such letters of credit are not drawn upon or, if and to the extent drawn upon, such drawing is reimbursed no later than the fifth Business Day following payment on the letter of credit), if and to the extent any of the foregoing (other than clauses (h) and (i)) would appear as a liability on a statement of financial position (excluding the footnotes thereto) of such Person prepared in accordance with IFRS, provided that "Indebtedness" shall not include customer deposits and advance payments received from customers for the sale, lease or license of goods and services (including natural gas transportation) in the ordinary course of business, whether or not such deposits or advance payments have been expensed in accordance with IFRS.

"*Indenture*" has the meaning set forth under the caption "—*General*."

"*Indenture Documents*" means, collectively, the Notes, the Note Guarantee, the Indenture, the Security Documents, any letter of credit or Guarantee provided in connection with the reserve accounts in accordance with the Security and Depositary Agreement and in effect from time to time.

"*Independent Engineer*" means Arup Latin America S.A or any successor or replacement thereof; provided that any such replacement shall be an independent engineering consulting firm with substantial expertise and experience in the construction, operation and maintenance of assets substantially similar to the Projects.

"*Insolvency Proceeding*," with respect to any Person, means (a) entry by any competent Governmental Authority of any jurisdiction or a court having jurisdiction in the premises of (i) a decree or order for relief in respect of such Person in an involuntary case or proceeding under any applicable Debtor Relief Law or (ii) an involuntary or contested decree or order adjudging such Person as bankrupt or insolvent, or approving as properly filed a petition seeking suspension of payment, reorganization, moratorium, arrangement, adjustment or composition of or in respect of such Person under any applicable Debtor Relief Law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Person or of any substantial part of the property of such Person, or ordering the dissolution, winding up or liquidation of the affairs of such Person and the continuance of any such decree or order referred to in clauses (i) and (ii) above remains undismissed or unstayed and in effect for a period of ninety (90) consecutive days, (b) commencement by such Person of a voluntary case or proceeding under any applicable Debtor Relief Law or of any other case or proceeding to be adjudicated as bankrupt or insolvent, or the consent by such Person to the entry of a decree or order for relief in respect of such Person in an involuntary case or proceeding under any applicable Debtor Relief Law or to the commencement of any bankruptcy or insolvency case or proceeding against such Person, or the filing by such Person of a petition or answer or consent seeking reorganization or relief under any applicable Debtor Relief Law; or consent by such Person to the filing of such petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Person or of any substantial part of the property of such Person, or the making by such Person of an assignment for the benefit of creditors or (c) the admission by such Person in writing of its inability to pay its debts generally as they become due, or the taking of corporate action by such Person in furtherance of any such action.

"*Intercompany Loan*" means any Indebtedness incurred between or among the Issuer or any Guarantor; provided that such Indebtedness shall be pledged as Collateral for the benefit of the Secured Parties and provided, further, that collection and other enforcement rights thereunder shall be expressly subordinated to the prior payment in full of all obligations with respect to the Notes or the Note Guarantees.

"*Intercreditor Agent*" has the meaning set forth under the caption "*—Intercreditor Arrangements*."

"*Intercreditor Vote*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*Interest Rate Agreement*" means with respect to any Person any interest rate protection agreement, interest rate futures contract, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement as to which such Person is party or a beneficiary.

"*Investment*" in any Person means, without duplication: (1) the acquisition (whether for cash, securities, other Property, services or otherwise) or holding of bonds, notes, debentures, partnership, Equity Interests or other ownership interests or other securities of such Person, or any agreement to make any such acquisition or to make any capital contribution (excluding commissions, travel and similar advances to officers and employees made in the ordinary course of business) to such Person; or (2) the making of any deposit with, or advance, loan or other extension of credit to, such Person.

"*Issue Date*" means the date on which the Notes were originally issued under the Indenture.

"*Issuer*" has the meaning set forth under the caption "*—General*."

"*Issuing Lender*" has the meaning set forth under the caption "*—LC Facility Agreement*."

"*LC Facility Agreement*" has the meaning set forth under the caption "*—LC Facility Agreement*."

"*LCF Obligations*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Pari Passu Benefits*."

"*Lender*" has the meaning set forth under the caption "*—LC Facility Agreement*."

"*Letter of Credit*" has the meaning set forth under the caption "—*LC Facility Agreement*."

"*Letter of Credit Secured Parties*" has the meaning set forth under the caption "—*Intercreditor Arrangements*."

"*Lien*" means any mortgage, deed of trust, lien, security interest, pledge, hypothecation, assignment, deposit arrangement or other charge or encumbrance of any kind, or a mandate to create the same, including, without limitation, the Lien or retained security title of a conditional vendor (excluding operating leases) and any easement, right of way or other encumbrance on title to real Property or anything analogous to any of the foregoing under the laws of any jurisdiction. For the avoidance of doubt, any preference of one creditor in the ordinary course over another arising by operation of law shall not be considered as a Lien.

"*Long-Term Power Purchase Agreements*" means each of the power purchase agreements listed below:

(1) Energy and Power Supply Contract (non-DisCo PPA), between San Juan and Enel Distribución Chile S.A. (assigned to Enel Generación Chile S.A) dated August 22, 2019.

(2) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and CGE Distribución S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19531/2015.

(3) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and CGE Distribución S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19533/2015.

(4) Energy and Power Supply Contract (PPA) Block 3, between San Juan and CGE Distribución S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19534/2015.

(5) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Compañía Nacional de Fuerza Eléctrica S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19525/2015.

(6) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Compañía Nacional de Fuerza Eléctrica S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19526/2015.

(7) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Compañía Nacional de Fuerza Eléctrica S.A., executed by public deed dated June 10, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19707/2015.

(8) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Empresa Eléctrica Atacama S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19505/2015.

(9) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Empresa Eléctrica Atacama S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19511/2015.

(10) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Empresa Eléctrica Atacama S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19513/2015.

(11) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Empresa Eléctrica de Antofagasta S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19522/2015.

(12) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Empresa Eléctrica de Antofagasta S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19524/2015.

(13) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Empresa Eléctrica de Antofagasta S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Juan Ricardo San Martín Urrejola, under repertoire number 19518/2015.

(14) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Luzlinares S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.896/2015.

(15) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Luzlinares S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.902/2015.

(16) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Luzlinares S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.900/2015.

(17) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Luzparral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.909/2015.

(18) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Luzparral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.910/2015.

(19) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Luzparral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.911/2015.

(20) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Chilquinta Energía S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.885/2015.

(21) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Chilquinta Energía S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.886/2015.

(22) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Chilquinta Energía S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.867/2015.

(23) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Energía de Casablanca S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.858/2015.

(24) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Energía de Casablanca S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.857/2015.

(25) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Energía de Casablanca S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.856/2015.

(26) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Compañía Eléctrica del Litoral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.891/2015.

(27) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Compañía Eléctrica del Litoral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.892/2015.

(28) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Compañía Eléctrica del Litoral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.894/2015.

(29) Energy and Power Supply Contract (PPA) Blocks 2-A, 2-C, 3, between San Juan and Chilectra S.A. (currently named ENEL Distribución Chile S.A), executed by public deed dated June 5, 2015, granted in the Santiago Notary office of Osvaldo Pereira González, under repertoire number 5.397/2015.

(30) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Compañía Eléctrica Osorno S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.711/2015.

(31) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Compañía Eléctrica Osorno S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.710/2015.

(32) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Compañía Eléctrica Osorno S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.706/2015.

(33) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Empresa Eléctrica de la Frontera S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.709/2015.

(34) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Empresa Eléctrica de la Frontera S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.689/2015.

(35) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Empresa Eléctrica de la Frontera S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.707/2015.

(36) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Sociedad Austral de Electricidad S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.712/2015.

(37) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Sociedad Austral de Electricidad S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.705/2015.

(38) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Sociedad Austral de Electricidad S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.713/2015.

(39) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Empresa Eléctrica de Casablanca S.A., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Mr. Eduardo Avello Concha, under repertoire number 21.430/2015.

(40) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Empresa Eléctrica de Casablanca S.A., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Mr. Eduardo Avello Concha, under repertoire number 21.432/2015.

(41) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Empresa Eléctrica de Casablanca S.A., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Mr. Eduardo Avello Concha, under repertoire number 21.433/2015.

(42) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa Eléctrica Curicó Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.066/2015.

(43) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa Eléctrica Curicó Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.083/2015.

(44) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa Eléctrica Curicó Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.070/2015.

(45) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa de Consumo de Energía Eléctrica de Chillán Ltda., executed by public deed dated June 11, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.584/2015.

(46) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa de Consumo de Energía Eléctrica de Chillán Ltda., executed by public deed dated June 11, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.585/2015.

(47) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa de Consumo de Energía Eléctrica de Chillán Ltda., executed by public deed dated June 11, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.586/2015.

(48) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa Eléctrica Los Ángeles Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.068/2015.

(49) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa Eléctrica Los Ángeles Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.085/2015.

(50) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa Eléctrica Los Ángeles Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.073/2015.

(51) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa Eléctrica Paillaco Ltda., executed by public deed dated July 8, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.852/2015.

(52) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa Eléctrica Paillaco Ltda., executed by public deed dated July 8, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.853/2015.

(53) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa Eléctrica Paillaco Ltda., executed by public deed dated July 8, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci under repertoire number 7.851/2015.

(54) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa Regional Eléctrica de Llanquihue Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.065/2015.

(55) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa Regional Eléctrica de Llanquihue Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.081/2015.

(56) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa Regional Eléctrica de Llanquihue Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.069/2015.

(57) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Cooperativa Rural Eléctrica de Río Bueno Ltda., executed by public deed dated June 25, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.316/2015.

(58) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Cooperativa Rural Eléctrica de Río Bueno Ltda., executed by public deed dated June 25, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.318/2015.

(59) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Cooperativa Rural Eléctrica de Río Bueno Ltda., executed by public deed dated June 25, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.317/2015.

(60) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.067/2015.

(61) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.084/2015.

(62) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.071/2015.

(63) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Compañía Distribuidora de Energía Eléctrica CODINER Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Diez Morello, under repertoire number 19.073/2015.

(64) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Compañía Distribuidora de Energía Eléctrica CODINER Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Diez Morello, under repertoire number 19.074/2015.

(65) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Compañía Distribuidora de Energía Eléctrica CODINER Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Diez Morello, under repertoire number 19.075/2015.

(66) Energy and Power Supply Contract (PPA) Block 2-A, between San Juan and Empresa Eléctrica Puente Alto Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Avello Concha, under repertoire number 21.418/2015.

(67) Energy and Power Supply Contract (PPA) Block 2-C, between San Juan and Empresa Eléctrica Puente Alto Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Avello Concha, under repertoire number 21.420/2015.

(68) Energy and Power Supply Contract (PPA) Block 3, between San Juan and Empresa Eléctrica Puente Alto Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Avello Concha, under repertoire number 21.421/2015.

(69) Power Purchase Agreement Metro, between San Juan and Empresa de Transporte de Pasajeros Metro S.A., dated May 19, 2016 and amended September 11, 2017 and May 13, 2021.

(70) Energy and Power Supply Contract (PPA) Block 4, between Norvind and CGE Distribución S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Ricardo San Martín Urrejola, under repertoire number 19493/2015.

(71) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Compañía Nacional de Fuerza Eléctrica S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Ricardo San Martín Urrejola, under repertoire number 19499/2015.

(72) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Empresa Eléctrica Atacama S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Ricardo San Martín Urrejola, under repertoire number 19500/2015.

(73) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Empresa Eléctrica de Antofagasta S.A., executed by public deed dated June 9, 2015, granted in the Santiago Notary office of Ricardo San Martín Urrejola, under repertoire number 19503/2015.

(74) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Luzlinares S.A., and executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.903/2015.

(75) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Luzparral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices under repertoire number 6.912/2015.

(76) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Chilquinta Energía S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.887/2015.

(77) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Energía de Casablanca S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.855/2015.

(78) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Compañía Eléctrica del Litoral S.A., executed by public deed dated June 17, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.895/2015.

(79) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Chilectra S.A. (currently named ENEL Distribución Chile S.A), executed by public deed dated June 5, 2015, granted in the Santiago Notary office of Osvaldo Pereira González, under repertoire number 5.398/2015.

(80) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Compañía Eléctrica Osorno S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.691/2015.

(81) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Empresa Eléctrica de la Frontera S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.708/2015.

(82) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Sociedad Austral de Electricidad S.A., executed by public deed dated May 8, 2015, granted in the Santiago Notary office of Mr. José Musalem Saffie, under repertoire number 4.692/2015.

(83) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Empresa Eléctrica de Casablanca S.A., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Mr. Eduardo Avello Concha, under repertoire number 21.434/2015.

(84) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa Eléctrica de Curicó Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.058/2015.

(85) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa de Consumo de Energía Eléctrica de Chillan Ltda., executed by public deed dated June 11, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 6.583/2015.

(86) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa Eléctrica Los Ángeles Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.060/2015.

(87) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa Eléctrica Paillaco Ltda., executed by public deed dated July 8, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.850/2015.

(88) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa Regional Eléctrica Llanquihue Ltda., executed by public deed dated July 10, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 8.004/2015.

(89) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Cooperativa Rural Eléctrica de Rio Bueno Ltda., executed by public deed dated June 25, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.315/2015.

(90) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Sociedad Cooperativa de Consumo de Energía Eléctrica Charrúa Ltda., executed by public deed dated June 19, 2015, granted in the Santiago Notary office of Humberto Santelices Narducci, under repertoire number 7.064/2015.

(91) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Compañía Distribuidora de Energía Eléctrica CODINER Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Diez Morello, under repertoire number 19.072/2015.

(92) Energy and Power Supply Contract (PPA) Block 4, between Norvind and Empresa Eléctrica Puente Alto Ltda., executed by public deed dated July 31, 2015, granted in the Santiago Notary office of Eduardo Avello Concha, under repertoire number 21.423/2015.

"*Loss Proceeds*" means any Casualty Proceeds or Condemnation Proceeds.

"*Loss Proceeds Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*Majority Holders*" means the noteholders of over 50% in aggregate principal amount of the Notes then outstanding.

"*Material Adverse Effect*" means an event or circumstance that would, or would reasonably be expected to, have a material adverse effect on: (a) our financial position, results of operations, asset conditions or operations, (b) our ability to perform our obligations under any Transaction Document to which we are a party or (c) the validity or priority of the Liens on the Collateral or the ability of the Trustee or any Security Agent to enforce its rights and remedies under the Indenture Documents.

"*Material Project Documents*" means, collectively:

(a) each Long-Term Power Purchase Agreement,

(b) each O&M Agreement,

(c) each Ground Lease,

(d) each other contract (including relating to the operation, maintenance, repair, financing or use of the Projects) or any other power purchase agreement or similar agreement entered into after the Issue Date with respect to the sale, transfer or disposal of the electrical output and ancillary services of any Project involving annual payments in excess of US$5.0 million (or its equivalent in the currency of payment) or that contains any obligations, the non-performance of which would reasonably be expected to have a Material Adverse Effect, and

(e) any Additional Material Project Document, in each case entered into by the Issuer or any Guarantor with any other Person.

"*Moody's*" means Moody's Investors Service, Inc. and its successors.

"*Net Available Amount*" means with respect to any Proceeds, such proceeds net of the related reasonable out-of-pocket costs or expenses (if any) and, if applicable, reasonable transaction costs, incurred by us in connection with the collection, enforcement, negotiation, consummation, settlement, proceedings, administration or other activity related to the receipt and/or collection of the relevant proceeds, as applicable and excluding the proceeds of any business interruption insurance.

"*Non-Material Project Documents*" means, collectively, each other contract or any other power purchase agreement or similar agreement entered into before, on or after the Issue Date with respect to the sale, transfer or disposal of the electrical output and ancillary services of any Project involving annual payments below US$5.0 million (or its equivalent in the currency of payment) or that contains any obligations, the non-performance of which would not reasonably be expected to have a Material Adverse Effect.

"*Norvind*" has the meaning set forth under the caption "*—General*."

"*Note Guarantee*" means the Guarantee by each Guarantor of the Issuer's obligations under the Notes, the Indenture and each other Indenture Document, executed pursuant to the provisions of the Indenture.

"*Note Payment Date*" has the meaning set forth under the caption "*—Principal, Maturity and Interest*."

"*Note Proceeds Account*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*noteholder*" has the meaning set forth under the caption "*—General*."

"*Notes*" has the meaning set forth under the caption "*—General*."

"*Numerator*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*O&M Agreement*" means each of the operation and maintenance and turbine service agreements listed below, or any operation and maintenance or turbine service agreement or similar agreement entered into after the Issue Date in accordance with the Indenture related to the operation and maintenance of any Project:

1. Service and Availability Agreement, between San Juan and Vestas Chile Turbinas Eólicas Limitada, dated March 25, 2015 and amended by private instruments dated: December 14, 2016 and January 29, 2021.

2. Parent Company Guarantee over the Service and Availability Agreement, between San Juan and Vestas Wind Systems A/S, dated March 31, 2015.

3. Service and Availability Agreement, between Norvind and Vestas Chile Turbinas Eólicas Limitada, dated April 1, 2013, and amended December 14, 2016.

"*O&M Costs*" means, for any period, the amount actually paid by the Issuer in respect of (i) capital expenditures, (ii) purchases of materials, goods or services and other obligations of the Issuer under the Project Documents, (iii) all applicable taxes and (iv) other obligations relating to the operation, maintenance, repair or improvement of the Projects; provided, "O&M Costs" shall not include (i) any payments made in respect of the Indenture Documents or with respect to Indebtedness (including mandatory prepayments of principal), (ii) any Restricted Payments, (iii) any tax paid or payable by any of our direct or indirect equity owners with respect to the income or receipts of the Issuer; (iv) without duplication, any costs in respect of repairs and restoration, the cost of which (A) is funded from Event of Loss Proceeds deposited into the Loss Proceeds Accounts and are transferred by the Depositary Bank into the applicable Revenue Account in accordance with the Security and Depositary Agreement, (B) paid from the O&M Reserve Account, or (C) paid from Permitted Equity Issuances or Permitted Subordinated Indebtedness, except, with respect to clause (C) above, such expenses incurred to rebuild, replace, repair or restore the Project are reimbursed to the Issuer or the Guarantors from the Revenue Accounts, and (v) funded by amounts on deposit in any Unrestricted Account.

"*O&M Reserve Account*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*O&M Reserve Excess*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*O&M Reserve Requirement*" means, as of any monthly transfer date, an amount necessary to pay O&M Costs projected to be paid for the immediately following next three (3) month period in accordance with the Annual Budget.

"*Obsolete Asset*" means any asset that is worn out, obsolete or damaged from ordinary course wear and tear (to the extent of being unfit for normal use) or no longer necessary or required for the operation or maintenance of the Projects.

"*Offshore Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*Offshore Collateral Agent*" has the meaning set forth under the caption "*—General*."

"*Onshore Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*Onshore Collateral Agent*" has the meaning set forth under the caption "*—General*."

"*Operating Report*" means a semiannual operating report, prepared in good faith by the Issuer that includes in reasonable detail for each semi-annual period: (i) the generation profile of the Projects, (ii) the turbine availability of the Projects, (iii) any maintenance or other events impacting the operation of the Projects and (iv) environmental impact events including CO_2 avoidance and other green portfolio statistics.

"*Operations Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*Opinion of Counsel*" means an opinion from legal counsel who is reasonably acceptable to the Trustee or a Collateral Agent, as applicable, that meets the requirements described in the Indenture. The counsel may be an employee of or counsel to the Issuer, any Guarantor, the Trustee or a Collateral Agent.

"*Organizational Documents*" means, with respect to any Person, (1) the memorandum or articles of incorporation, limited liability company agreement, partnership agreement, *acta constitutiva* or other similar organizational document of such Person, (2) the by-laws, *estatutos* or other similar document of such Person, (3) any certificate of designation or instrument relating to the rights of preferred shareholders or other holders of Capital Stock of such Person and (4) any shareholder rights agreement or other similar agreement.

"*Paying Agent*" has the meaning set forth under the caption "*—General*."

"*Payment Date*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*PEC Receivables*" means the term "*Saldos*" assigned to in the Tariff Stabilization Resolution (*Resolución Exenta* No. 72) issued on March 5, 2020, by the *Comisión Nacional de Energía* of Chile or any successor entity, as clarified and rectified by the *Resolución Exenta* No. 114 issued on April 9, 2020, by the *Comisión Nacional de Energía* of Chile, as may be further amended, clarified or rectified in accordance with Applicable Law, and including any rights associated with such distribution companies' receivables, and any subsequent "*Saldos*," receivables, collection rights or other similar rights in favor of the Issuer or the Guarantors, created by the relevant Governmental Authority (including, without limitation, by the *Comisión Nacional de Energía* of Chile or the Ministry of Energy of Chile) having the effect of creating rights substantially similar to those created under the Tariff Stabilization Resolution and Applicable Law.

"*Permitted Business*" means the ownership, development, financing, construction, operation or maintenance of the Projects and any activities ancillary or incidental thereto.

"*Permitted Equity Issuance*" means the issuance of any Equity Interests by any of the Issuer or the Guarantors, which such Equity Interests will be subject to a first-priority Lien in favor of the relevant Collateral Agent for the benefit the noteholders pursuant to the terms of the Indenture.

"*Permitted Holders*" means Existing Holders and Qualified Owners.

"*Permitted Investments*" means any of the following:

(i) Investments in cash or Cash Equivalents;

(ii) Investments in (a) Hedging Obligations entered into in the ordinary course of business and not for speculative purposes and (b) any Intercompany Loan;

(iii) promissory notes and other noncash consideration (other than Equity Interests) received in connection with Dispositions;

(iv) Investments (including Indebtedness and Equity Interests) received in connection with the bankruptcy or reorganization of suppliers and customers or in settlement of delinquent obligations of, or other disputes with, customers and suppliers arising in the ordinary course of business or upon the foreclosure with respect to any secured investment or other transfer of title with respect to any secured investment;

(v) Investments constituting pledges and deposits made in the ordinary course of business in compliance with workers' compensation, unemployment insurance and other social security laws or regulations;

(vi) Investments constituting deposits to secure the performance of bids, trade contracts, leases, statutory obligations, surety and appeal bonds, performance bonds and other obligations of a like nature, in each case in the ordinary course of business; and

(vii) Investments made from proceeds in the Distribution Account following the deposit of such proceeds in accordance with the applicable provisions of the Indenture Documents.

"*Permitted Refinancing*" means, with respect to any Person, any modification, refinancing, refunding, replacement, renewal or extension of any Indebtedness of such Person; *provided* that (a) the principal amount (or accreted value, if applicable) thereof does not exceed the principal amount (or accreted value, if applicable) of the Indebtedness so modified, refinanced, refunded, replaced, renewed or extended except by an amount equal to unpaid accrued interest and premium (including tender premiums and Additional Amounts) thereon, plus reasonable original issue discount and upfront fees plus other fees and expenses reasonably incurred, in connection with such modification, refinancing, refunding, replacement, renewal or extension and by an amount equal to any existing commitments unutilized thereunder, (b) such modification, refinancing, refunding, renewal or extension has a final maturity date equal to or later than the final maturity date of, and has a Weighted Average Life to Maturity equal to or greater than the Weighted Average Life to Maturity of, the Indebtedness being modified, refinanced, refunded, renewed or extended, (c) if the Indebtedness being modified, refinanced, refunded, replaced, renewed or extended is subordinated in right of payment to the Notes and any other Senior Secured Obligations, the Indebtedness so modified, refinanced, refunded, replaced, renewed or extended is subordinated in right of payment to the Notes and any other Senior Secured Obligations on terms at least as favorable to the noteholders as those contained in the documentation governing the Indebtedness being modified, refinanced, refunded, replaced, renewed or extended and (d) the terms of such modification, refinancing, refunding, replacement, renewal or extension shall otherwise contain customary market terms (as reasonably determined by the Issuer).

"*Permitted Subordinated Indebtedness*" means, with respect to any Person, any unsecured Indebtedness of such Person that (1) is expressly subordinated in right of payment and liquidation to the Notes and the Note Guarantees, (2) is subject to a first-priority Lien in favor of the relevant Collateral Agent for the benefit of the Secured Parties pursuant to the Indenture, (3) does not require or permit any cash payment of any obligation thereunder prior to its Stated Maturity, except to the extent and in the amount that the Issuer or the Guarantors are permitted to make a Restricted Payment under the Indenture and (4) does not mature prior to the date that is 180 days after the Stated Maturity of the Notes.

"*Person*" means an individual, partnership, corporation, limited liability company, business trust, joint stock company, trust, unincorporated association, joint venture, other entity or Governmental Authority.

"*Pledge Agreement*" means each of the following pledge agreements governed under the laws of Chile:

1. Pledge without conveyance over existing and future equity rights (*prenda sin desplazamiento sobre derechos sociales*) by and among Latin America Power S.A. and Latin America Power Holding

B.V. in order to pledge to the Onshore Collateral Agent, for the benefit of the Secured Parties, one-hundred percent (100%) of their existing and future equity rights in ILAP.

2. Pledge without conveyance over existing and futures shares issued by Norvind (*prenda sin desplazamiento sobre acciones presentes y futuras*) by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, ILAP, Latin America Power S.A. and Norvind.

3. Pledge without conveyance over existing and futures shares issued by San Juan (*prenda sin desplazamiento sobre acciones presentes y futuras*) by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, ILAP, Latin America Power S.A. and San Juan.

4. Commercial pledge over existing Material Project Documents (other than Long Term Power Purchase Agreements) and promise to grant commercial pledge over future Material Project Documents (consisting in Long Term Power Purchase Agreements with non-DisCos) (*prenda comercial sobre derechos y promesa de prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

5. Commercial Pledge over existing Material Project Documents (other than Long Term Power Purchase Agreements) and promise to grant commercial pledge over future Material Project Documents (consisting in Long Term Power Purchase Agreements with non-DisCos) (*prenda comercial sobre derechos y promesa de prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

6. Promise to grant commercial pledges over future Material Project Documents (consisting in Long Term Power Purchase Agreements with non-DisCos), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and ILAP.

7. Commercial Pledge over existing Material Project Documents (consisting in Long Term Power Purchase Agreements with DisCos) (*prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

8. Commercial Pledge over existing Material Project Documents (consisting in Long Term Power Purchase Agreements with DisCos) (*prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

9. Commercial pledge over existing Material Project Documents (consisting in Long Term Power Purchase Agreements with non-DisCos) (*prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

10. Commercial pledge over Power Purchase Agreement with Empresa de Transporte de Pasajeros Metro S.A. (prenda comercial sobre derechos), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

11. Commercial pledge over Power Purchase Agreement with Enel Generación S.A. (prenda comercial sobre derechos), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

12. Commercial Pledge over existing Material Project Documents (consisting in Long Term Power Purchase Agreements with non-DisCos) (*prenda comercial sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

13. Pledge without conveyance over rights on future Material Project Documents (other than Long Term Power Purchase Agreements with non-DisCos) (*prenda sin desplazamiento sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

14. Pledge without conveyance over rights on future Material Project Documents (other than Long Term Power Purchase Agreements with non-DisCos) (*prenda sin desplazamiento sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

15. Pledge without conveyance over rights on Future Material Project Documents (other than Long Term Power Purchase Agreements with non-DisCos) (*prenda sin desplazamiento sobre derechos*), by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and ILAP.

16. Commercial pledge over electric concession (*prenda comercial sobre concesión eléctrica*) by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

17. Pledge without conveyance over existing and future movable Property (*prenda sin desplazamiento sobre activos*) by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

18. Pledge without conveyance over existing and future movable Property (*prenda sin desplazamiento sobre activos*) by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

19. Pledge without conveyance over future movable Property (*prenda sin desplazamiento sobre activos*) by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, and ILAP.

20. Pledge without conveyance over existing and future Intercompany Indebtedness (*prenda sin desplazamiento sobre créditos*), by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, ILAP and San Juan.

21. Pledge without conveyance over existing and future Intercompany Indebtedness (*prenda sin desplazamiento sobre créditos*), by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, ILAP and Norvind.

22. Pledge without conveyance over existing and future amounts deposited in certain onshore accounts and permitted investments (*prenda sin desplazamiento sobre dinero e inversiones permitidas*) by and between the Onshore Collateral Agent, for the benefit of the Secured Parties, and San Juan.

23. Pledge without conveyance over existing and future amounts deposited in certain onshore accounts and permitted investments (*prenda sin desplazamiento sobre dinero e inversiones permitidas*) by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, and Norvind.

24. Pledge without conveyance over existing and future amounts deposited in certain onshore accounts and permitted investments (*prenda sin desplazamiento sobre dinero e inversiones permitidas*) by and among the Onshore Collateral Agent, for the benefit of the Secured Parties, and ILAP.

"*Prior Security Documents*" has the meaning set forth under the caption "*—Collateral*."

"*Proceeds*" means Event of Loss Proceeds and proceeds from Dispositions as permitted by the Indenture.

"*Project Documents*" means, collectively, the Material Project Documents and the Non-Material Project Documents.

"*Project Party*" means each party to a Material Project Document other than the Issuer and the Guarantors.

"*Project Revenue*" means, for any period, the sum (without duplication) of all cash deposited into the Revenue Accounts during the most recently ended Calculation Period completed on or prior to such date of determination, including (i) PEC Receivables, (ii) proceeds of any business interruption insurance actually received and required to be deposited in the Revenue Accounts in accordance with the Security and Depositary Agreement, and (iii) interest and other amounts received on, and other income derived from, the balance outstanding during such period in the Collateral Accounts (including, without limitation, proceeds from Permitted Investments)), but excluding (A) cash proceeds from any other insurance policies, from warranty or indemnity payments or from damages and (B) cash deposited into the Revenue Account from Permitted Equity Issuances or Permitted Subordinated Indebtedness.

"*Project Site*" means, with respect to each Project, (i) the land upon which such Project is located, and (ii) the rights-of-way, licenses, leases and other interests in real property vested in the applicable Guarantor in connection with such Project.

"*Projected Debt Service Coverage Ratio*" means, for any period, the ratio of (i) the projected aggregate amount of Cash Available for Debt Service for such period, which shall be calculated in good faith by the Issuer using reasonable assumptions to (ii) the aggregate amount of all Debt Service estimated to be payable in such period, which, in each case, shall be calculated assuming that (a) there will be no early redemption or prepayment of Indebtedness and (b) any Indebtedness which matures within the projected period will be refinanced on reasonable terms; provided that (i) projected O&M Costs for any period shall not be less than the amount projected therefor in the Base Case Model and (ii) projected Project Revenue for any period shall not be greater than the amount set out therefor in the Base Case Model. Such calculation shall be made by a Responsible Officer of the Issuer consistent with the projected financial information set forth in the offering memorandum relating to the initial issuance of the Notes.

"*Projects*" means the wind generation assets corresponding to the San Juan Project and the Totoral Project.

"*Property*" means any property of any kind whatsoever, whether real, personal or mixed and whether tangible or intangible, and any right or interest therein. The term "Properties" shall have a correlative meaning.

"*Prudent Industry Practices*" means those practices, methods, techniques and standards that are generally accepted in Chile, as they may change from time to time, for use in the electric energy industry and commonly used in safe and prudent electric energy engineering and operations to design, engineer, construct, test, operate and maintain equipment similar to the Projects.

"*Purchase Money Indebtedness*" means all obligations of a Person issued or assumed as the deferred purchase price of property, all conditional sale obligations and all obligations under any title retention agreement due more than six months after such property is acquired and excluding trade payables and other accrued liabilities arising in the ordinary course of business that are not overdue by 30 days or more or are being contested in good faith by appropriate proceedings promptly instituted and diligently conducted.

"*Qualified Owner*" means a Person (or the direct or indirect parent of such Person (or parents of such Person, if owned by a consortium) (such parent or parents (collectively), a "*QO Parent*") (whether directly or indirectly through one or more of its Subsidiaries) (a) has a net worth of at least $250,000,000, or, if such Person (or any QO Parent) is a private equity fund or a similar fund, such Person or QO Parent has (or, in the case of a consortium, the QO Parents collectively have), a net worth plus uncommitted commitments from its investors of at least $250,000,000 (it being understood that such "net worth" may be determined in any one of the following ways: market capitalization, book equity on the balance sheet, assets under management, fund size or verifiable cash balance); and (b) possesses, or if any such Person (or any QO Parent) is a private equity fund or a similar fund, the fund manager of any such Person or QO Parent (including through ownership of other investments), possesses, the level of experience (either directly or indirectly through an agreement with a third party operator, such agreement to be in form and substance reasonably satisfactory to the Independent Engineer) with technologies and business practices relevant to operating renewable energy generation facilities with capacity in excess of 200 MW. In addition, any Person or QO Parent that meets the requirements in the foregoing clause (a) shall be a Qualified Owner so long as (A) the executive management of the Issuer has the level of experience with technologies and business practices relevant to operating wind power generation facilities similar to the Project in accordance with applicable operating requirements; provided, each of the persons acting as chief executive officer, chief financial officer and chief operating officer of the Issuer as of the Issue Date are deemed to have such requisite level of experience and (B) the O&M Agreements are in full force and effect during the initial term of such agreement (or such other agreement on substantially similar terms is in full force and effect during such initial term).

"*Rating Agency*" means, initially, each of Moody's, S&P and Fitch or, if Moody's, S&P or Fitch or any of them shall not make a rating on the Notes publicly available, a nationally recognized statistical rating organization (or two such organizations, as the case may be), as such term is defined in Section 3(a)(62) of the Exchange Act, selected by the Issuer which shall be substituted for any of Fitch, Moody's or S&P, as the case may be, and their respective successors.

"*Ratings Affirmation*" means, with respect to any particular action or proposed action, any two of S&P, Moody's or Fitch or, if any or all of such ratings agencies do not then rate the Notes, such other Rating Agencies then having issued long-term debt ratings for the Notes, affirms that such long-term debt ratings will not be lowered as a result of the taking of such action or proposed action.

"*Registrar*" has the meaning set forth under the caption "*—General*."

"*Remedies Instruction*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Defaults and Remedies*."

"*Replacement Assets*" means tangible Property that will be used or useful in connection with a Permitted Business other than the Capital Stock of any Person.

"*Required Secured Parties*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*Reserve Letter of Credit*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Offshore Accounts*."

"*Responsible Officer*" means the Chief Executive Officer, the President, any of the managers, any of the directors, or any Vice President of such Person or of the controlling shareholder of such Person, in each case whose name appears on a certificate of incumbency of such Person delivered in accordance with the terms of the Indenture, as such certificate may be amended from time to time.

"*Revenue Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*S&P*" means Standard & Poor's Ratings Services, Inc. or any successor thereto.

"*Sale and Lease-Back Transaction*" means any arrangement with any Person, or to which any such Person is a party, providing for the leasing to the Issuer for a period of more than three years of any Property or assets that have been or are to be sold or transferred by the Issuer to such Person or to any other Person to which funds have been or are to be advanced by such Person on the security of the leased Property or assets.

"*San Juan*" has the meaning set forth under the caption "*—General*."

"*Secured Documents*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Priority of Payments*."

"*Secured Parties*" means the Trustee, the noteholders, the Security Agents and any lender or agent under a Senior Debt Facility.

"*Security Agents*" means, collectively, the Trustee, the Administrative Agent, the Intercreditor Agent, the Collateral Agents and the Depositary Banks, as applicable.

"*Security and Depositary Agreement*" means the security and depositary agreement dated as of the Issue Date among the Issuer, the Guarantors, the Intercreditor Agent, the Trustee, the Administrative Agent, the Offshore Collateral Agent, Citibank, N.A. as offshore depositary bank (in such capacity, the "*Offshore Depositary Bank*"), the

Onshore Collateral Agent, and Banco de Chile as onshore depositary bank (in such capacity, the "*Onshore Depositary Bank*").

"*Security Documents*" means, collectively, (i) each Chilean Law Security Document, (ii) the Security and Depositary Agreement and (iii) any other mortgages, deeds of trust, security agreements, mandates, trust arrangements, pledge agreements or control agreements entered into after the Issue Date and of a similar nature relating to the Projects or the financing contemplated by this offering, in each case for the benefit of the Secured Parties.

"*Senior Debt Facility*" means the Indenture and the LC Facility Agreement.

"*Senior Secured Obligations*" means, collectively, without duplication: (i) all of our Indebtedness, financial liabilities and obligations, of whatsoever nature and howsoever evidenced (including, but not limited to, principal, interest, fees, reimbursement obligations, penalties, indemnities and legal and other expenses, whether due after acceleration or otherwise) to the Secured Parties in their capacity as such under the applicable Senior Debt Facility Agreement or any other agreement, document or instrument evidencing, securing or relating to such Indebtedness, financial liabilities or obligations, in each case, direct or indirect, primary or secondary, fixed, variable or contingent, now or hereafter arising out of or relating to any such agreements; (ii) any and all sums advanced by the Security Agents in order to preserve the Collateral or preserve its security interest in the Collateral; (iii) in the event of any proceeding for the collection or enforcement of the obligations described in clauses (i) and (ii) above, after an Event of Default under the Indenture has occurred and is continuing and has not been waived, the reasonable expenses of retaking, holding, preparing for sale or lease, selling or otherwise disposing of or realizing on the Collateral, or of any exercise by the Security Agents of their respective rights under the Security Documents, together with reasonable attorneys' fees and court costs; and (iv) Erroneous Payments Subrogation Rights (as defined in the LC Facility Agreement).

"*SGX*" means the Singapore Exchange Securities Trading Limited.

"*Shared Collateral*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Shared Collateral*."

"*Stated Maturity*" means (1) with respect to any Indebtedness, the date specified as the fixed date on which the final installment of principal of such Indebtedness is due and payable or (2) with respect to any scheduled installment of principal of or interest on any Indebtedness, the date specified as a fixed date on which such installment is due and payable as set forth in the documentation governing such Indebtedness, not including any contingent obligation to repay, redeem or repurchase prior to the regularly scheduled date for payment.

"*Subsidiary*" means with respect to any Person, any corporation, association or other business entity of which more than 50% of the outstanding Voting Stock is owned, directly or indirectly, by such Person and one or more Subsidiaries of such Person (or a combination thereof).

"*Swap Agreement*" means any Commodity Agreement, Currency Agreement or Interest Rate Agreement.

"*Target Debt Balance*" means each target debt balance set forth below corresponding to each Note Payment Date:

Scheduled Payment Dates	**Target Debt Balance (thousands of US$)**
03 January, 2022	397,761.00
03 July, 2022	390,221.00
03 January, 2023	383,564.00
03 July, 2023	377,599.00
03 January, 2024	368,994.00

03 July, 2024	362,170.00
03 January, 2025	352,259.00
03 July, 2025	339,061.00
03 January, 2026	322,947.00
03 July, 2026	307,872.00
03 January, 2027	289,671.00
03 July, 2027	272,124.00
03 January, 2028	252,561.00
03 July, 2028	237,957.00
03 January, 2029	220,196.00
03 July, 2029	202,797.00
03 January, 2030	183,503.00
03 July, 2030	164,423.00
03 January, 2031	143,607.00
03 July, 2031	123,262.00
03 January, 2032	100,875.00
03 July, 2032	82,052.00
03 January, 2033	62,039.00
15 June, 2033	49,511.00

"*Target Debt Balance Cash Sweep*" has the meaning set forth under the caption "—*Cash Sweep Mandatory Redemption*."

"*Taxes*" means any and all income, stamp or other taxes, duties, levies, imposts, charges, fees, deductions or withholdings, now or hereafter imposed, levied, collected, withheld or assessed by or on behalf of a Taxing Jurisdiction.

"*Taxing Jurisdiction*" means any Governmental Authority of Chile or any other jurisdiction or political subdivision thereof or therein in which the Issuer is organized or is a resident for tax purposes, or any jurisdiction from or through which the Issuer or any paying agent, as the case may be, makes payment hereunder, or any political subdivision thereof.

"*Transaction Documents*" means the Indenture Documents and the Material Project Documents.

"*Transfer Agent*" has the meaning set forth under the caption "—*General*."

"*Trustee*" has the meaning set forth under the caption "—*General*."

"*U.S. Government Obligations*" means securities that are (a) non-callable direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged or (b) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the timely payment of which is unconditionally guaranteed as a full faith and credit obligation of the United States of America, which, in either case, are not callable or redeemable at the option of the issuer thereof, and shall also include a depositary receipt issued by a bank (as defined in Section 3(a)(2) of the Securities Act), as custodian with respect to any such U.S. Government Obligations or a specific payment of principal of or interest on any such U.S. Government Obligations held by such custodian for the account of the holder of such depositary receipt; provided that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depositary receipt from any amount received by the custodian in respect of the U.S. Government Obligations or the specific payment of principal of or interest on the U.S. Government Obligations evidenced by such depositary receipt.

"*Unrestricted Accounts*" has the meaning set forth under the caption "*—Collateral Accounts and Priority of Payments—Onshore Accounts*."

"*Voting Secured Parties*" has the meaning set forth under the caption "*—Intercreditor Arrangements—Voting*."

"*Voting Stock*" with respect to any Person, means Capital Stock the holders of which are ordinarily, in the absence of contingencies, entitled to vote for the election of directors (or persons performing similar functions) of such Person, even if the right so to vote has been suspended by the happening of a contingency.

"*Weighted Average Life to Maturity*" means, when applied to any Indebtedness at any date, the number of years obtained by dividing: (a) the sum of the products obtained by multiplying (i) the amount of each then remaining installment, sinking fund, serial maturity or other required payments of principal, including payment at final maturity, in respect thereof, by (ii) the number of years (calculated to the nearest one-twelfth) that will elapse between such date and the making of such payment by (b) the then outstanding principal amount of such Indebtedness; *provided* that for purposes of determining the Weighted Average Life to Maturity of any Indebtedness that is being modified, refinanced, refunded, renewed, replaced or extended (the "*Applicable Indebtedness*"), the effects of any prepayments made on such Applicable Indebtedness prior to the date of the applicable modification, refinancing, refunding, renewal, replacement or extension shall be disregarded.

FORM OF NOTES, CLEARING AND SETTLEMENT

Global Notes

The Notes will initially be issued in the form of two registered notes in global form, without interest coupons (the "*Global Notes*"), as follows:

- notes sold to qualified institutional buyers under Rule 144A will be represented by the Rule 144A Global Note; and

- notes sold in offshore transactions to non-U.S. persons in reliance on Regulation S will initially be represented by the Regulation S Global Note.

Upon issuance, the Rule 144A Global Note and Regulation S Global Note will be deposited with the Trustee as custodian for DTC and registered in the name of Cede & Co., as nominee of DTC.

Ownership of beneficial interests in each Global Note will be limited to persons who have accounts with DTC ("*DTC Participants*") or persons who hold interests through DTC Participants. We expect that under procedures established by DTC:

- upon deposit of each Global Note with DTC's custodian, DTC will credit portions of the principal amount of the Global Note to the accounts of the DTC participants designated by the Initial Purchasers and

- ownership of beneficial interests in each Global Note will be shown on, and transfer of ownership of those interests will be effected only through, records maintained by DTC (with respect to interests of DTC participants) and the records of DTC participants (with respect to other owners of beneficial interests in the Global Note).

Beneficial interests in the Global Notes may not be exchanged for notes in physical, certificated form except in the limited circumstances described below.

Each Global Note and beneficial interests in each Global Note will be subject to restrictions on transfer as described under "*Transfer Restrictions*."

Exchanges between the Global Notes

A beneficial interest in a Global Note that is transferred to a person who takes delivery through another Global Note will, upon transfer, become subject to any transfer restrictions and other procedures applicable to beneficial interests in the other Global Note.

Book-Entry Procedures for the Global Notes

All interests in the Global Notes will be subject to the operations and procedures of DTC, Euroclear and Clear Stream Luxemburg. We provide the following summaries of those operations and procedures solely for the convenience of investors. The operations and procedures of each settlement system are controlled by that settlement system and may be changed at any time. None of the Trustee, any agent under the Trustee or the Initial Purchasers is responsible for those operations or procedures.

DTC has advised that it is:

- a limited purpose trust company organized under the New York State Banking Law;

- a "banking organization" within the meaning of the New York State Banking Law;

- a member of the U.S. Federal Reserve System; a "clearing corporation" within the meaning of the New York Uniform Commercial Code; and

- a "clearing agency" registered under Section 17A of Exchange Act.

DTC was created to hold securities for its participants and to facilitate the clearance and settlement of securities transactions between its participants through electronic book-entry changes to the accounts of its participants. DTC's Participants include securities brokers and dealers, including the Initial Purchasers; banks and trust companies; clearing corporations; and certain other organizations. Indirect access to DTC's system is also available to others such as banks, brokers, dealers and trust companies; these indirect participants clear through or maintain a custodial relationship with a DTC Participant, either directly or indirectly. Investors who are not DTC Participants may beneficially own securities held by or on behalf of DTC only through DTC Participants or indirect participants in DTC.

So long as DTC or its nominee is the registered owner of a Global Note, DTC or its nominee will be considered the sole owner or holder of the Notes represented by that Global Note for all purposes under the Indenture. Except as provided below, owners of beneficial interests in a Global Note:

- will not be entitled to have Notes represented by the Global Note registered in their names;

- will not receive or be entitled to receive physical, certificated Notes; and

- will not be considered the registered owners or holders of the Notes under the Indenture for any purpose, including with respect to the giving of any direction, instruction or approval to the Trustee under the Indenture.

As a result, each investor who owns a beneficial interest in a Global Note must rely on the procedures of DTC to exercise any rights of a holder of Notes under the Indenture (and, if the investor is not a participant or an indirect participant in DTC, on the procedures of the DTC Participant through which the investor owns its interest).

Payments of principal, premium, if any, and interest with respect to the Notes represented by a Global Note will be made by the Trustee to DTC's nominee as the registered holder of the Global Note. Neither the Issuer, the Trustee, nor any agent will have any responsibility or liability for the payment of amounts to owners of beneficial interests in a Global Note, for any aspect of the records relating to or payments made on account of those interests by DTC, or for maintaining, supervising or reviewing any records of DTC relating to those interests.

Payments by participants and indirect participants in DTC to the owners of beneficial interests in a Global Note will be governed by standing instructions and customary practices and will be the responsibility of those participants or indirect participants and not of DTC, its nominee or the Issuer.

Transfers between participants in DTC will be effected under DTC's procedures and will be settled in same-day funds. Transfers between participants in Euroclear and Clearstream, Luxembourg will be effected in the ordinary way under the rules and operating procedures of those systems.

Cross-market transfers between DTC Participants, on the one hand, and Euroclear or Clearstream, Luxembourg participants, on the other hand, will be effected within DTC through the DTC Participants that are acting as depositaries for Euroclear and Clearstream, Luxembourg. To deliver or receive an interest in a Global Note held in a Euroclear or Clearstream, Luxembourg account, an investor must send transfer instructions to Euroclear or Clearstream, Luxembourg, as the case may be, under the rules and procedures of that system and within the established deadlines of that system. If the transaction meets its settlement requirements, Euroclear or Clearstream, Luxembourg, as the case may be, will send instructions to its DTC depositary to take action to effect final settlement by delivering or receiving interests in the relevant Global Notes in DTC, and making or receiving payment under normal procedures for same-day funds settlement applicable to DTC. Euroclear or Clearstream, Luxembourg participants may not deliver instructions directly to the DTC depositaries that are acting for Euroclear or Clearstream, Luxembourg.

Because of time zone differences, the securities account of a Euroclear or Clearstream, Luxembourg participant that purchases an interest in a global note from a DTC participant will be credited on the business day for Euroclear or Clearstream, Luxembourg immediately following the DTC settlement date. Cash received in Euroclear or Clearstream, Luxembourg from the sale of an interest in a Global Note to a DTC participant will be received with value on the DTC settlement date but will be available in the relevant Euroclear or Clearstream, Luxembourg cash account as of the business day for Euroclear or Clearstream, Luxembourg following the DTC settlement date.

DTC, Euroclear and Clearstream, Luxembourg have agreed to the above procedures to facilitate transfers of interests in the Global Notes among participants in those settlement systems. However, the settlement systems are not obligated to perform these procedures and may discontinue or change these procedures at any time. None of us, the Trustee or any agent under the Indenture will have any responsibility for the performance by DTC, Euroclear or Clearstream, Luxembourg or their participants of indirect participants of their obligations under the rules and procedures governing their operations.

Certificated Notes

Beneficial interests in the Global Notes may not be exchanged for notes in physical, certificated form unless:

- DTC notifies the Issuer at any time that it is unwilling or unable to continue as depositary for the Global Notes and a successor depositary is not appointed within 90 days;

- DTC ceases to be registered as a clearing agency under the Securities Exchange Act of 1934 and a successor depositary is not appointed within 90 days;

- The Issuer, at its option, notifies the Trustee that it elects to cause the issuance of certificated notes; or

- Certain other events provided in the Indenture should occur, including the occurrence and continuance of an event of default with respect to the Notes, and a request for such exchange has been made by the holder.

In all cases, certificated notes delivered in exchange for any Global Note will be registered in the names, and issued in any approved denominations, requested by the depositary and will bear a legend indicating the transfer restrictions of that particular Global Note.

For information concerning paying agents and transfer agents for any Notes in certificated form, see "*Description of the Notes—Principal, Maturity and Interest*" and "*Description of the Notes—Paying Agents; Transfer Agents and Registrar*."

TAXATION

The following discussion summarizes certain Chilean and U.S. federal income tax considerations that may be relevant to you if you purchase, own or sell the Notes. This summary is based on laws, regulations, rulings and decisions now in effect in each of these jurisdictions, including any relevant tax treaties. Unless expressly noted, any change could apply retroactively and could affect the continued validity of this summary.

This summary does not describe all of the tax considerations that may be relevant to you or your situation, particularly if you are subject to special tax rules.

You should consult your tax advisor about the tax consequences of the acquisition, ownership and disposition of the Notes, including the relevance to your particular situation of the considerations discussed below, as well as of any foreign, state, local or other tax laws.

The following discussion does not address tax consequences applicable to holders of the Notes in particular jurisdictions that may be relevant to such holder. Holders of the Notes are urged to consult their own tax advisors as to the overall tax consequences of the acquisition, ownership and disposition of the Notes in relevant jurisdictions.

Chilean Tax Considerations

The following is a summary of the material tax considerations under the Chilean tax law, as in effect, of an investment in the Notes made by a Foreign Holder (as defined below). This summary is based on the Chilean tax laws as in effect on the date of this offering memorandum, as well as regulations, rulings and decisions of Chile available on or before such date and now in effect. Under Chilean law, provisions contained in statutes, such as tax rates applicable to foreign investors, the computation of taxable income for Chilean purposes and how Chilean taxes are imposed and collected may be amended only by another law or by virtue of the ratification of an international tax treaty which directly addresses the subject matter. All the foregoing is subject to interpretation by the Chilean tax authority through rulings and regulations of general and/or specific application. New interpretations of the Chilean tax authority cannot be applied retroactively to taxpayers who relied on a particular ruling or regulation in good faith. All rulings and regulations containing amendments to previous rulings or regulations must be published in the Official Gazette. However, sometimes such publications are omitted.

For purposes of this summary the term "*Foreign Holder*" means either:

(i) in the case of an individual, a person who is not a resident of or domiciled in Chile. For tax purposes, an individual holder is a resident in Chile if he or she has remained in Chile for more than 183 days within a 12 months period, and an individual is domiciled in Chile if he or she resides in Chile with the actual or presumptive intent of staying in Chile (such intention to be evidenced by circumstances such as the acceptance of employment in Chile or the relocation of one's family to Chile); or

(ii) in the case of a legal entity, an entity that is not organized or incorporated under the laws of Chile, except if that legal entity assigns the Notes to a branch or a permanent establishment of such entity in Chile, it would cease to be a Foreign Holder.

Payments of interest or premium

Under the Chilean Income Tax Law (*Ley Sobre Impuesto a la Renta*) payments of interest or premium, if any, made to a Foreign Holder in respect of the Notes will generally be subject to withholding tax, currently at the rate of 4%. However, interest, premiums, remuneration for services, financial expenses and any other contractual surcharges paid, credited to an account or made available to entities related to the Issuer in respect of loans or liabilities (e.g., notes) during the year in which the indebtedness is considered to be excessive, are subject to a single tax at a rate of 35% that will be applied to us separately. However, withholding taxes already paid can be used as a credit against the applicable 35% single tax. Our indebtedness will be considered to be excessive ("*Excessive Indebtedness*") when at the end of the corresponding fiscal year we have a "total annual indebtedness" with entities incorporated, domiciled, residing or established whether in a foreign country or in Chile, either related to the Issuer or not, that exceeds three times our tax adjusted equity, as calculated for Chilean tax purposes. Although, short term debts acquired with related parties (i.e. with a maturity term of less than 90 days) may be excluded from the "total annual indebtedness" calculation. Consequently, interest or premium paid to entities related to the Issuer with respect to debt that exceeds the Excessive Indebtedness ratio will be subject to a 35% tax applicable to the Issuer.

Under the excessive indebtedness rules, a lender or creditor, such as a holder of the Notes, will be deemed to be related to the payor or debtor, if: (i) the beneficiary (i.e., lender or creditor) is incorporated, domiciled, resident or established in one of the territories or jurisdictions listed in section 41 H of the Chilean Income Tax Law (harmful preferential tax regimes, as defined within the same section 41 H); or (ii) the beneficiary (i.e., lender or creditor) or debtor belongs to the same corporate group, or directly or indirectly, owns or participates in 10% or more of the capital or the profits of the other or if lender and debtor have a common partner or shareholder which, directly or indirectly, owns or participates in 10% or more of the capital or the profits of one or the other, and that beneficiary is incorporated, domiciled, resident or established outside Chile; or (iii) the debt is guaranteed directly or indirectly by a related third party, (as specified herein) domiciled or a resident outside of Chile that is the beneficial owner of the interest payments made by the debtor; or (iv) it refers to securities placed and acquired by independent entities and that are subsequently acquired or transferred to a related entity according to prior numbers (i) to (iii); or (v) a party carries out one or more transactions with a third party who, in turn, carries out, directly or indirectly, with a related party of the first party, one or more operations similar or identical to those carried out with the first party, whatever the quality in which said third party and the parties intervene in such operations. The debtor will be required to issue a sworn statement in this regard in the form set forth by the Chilean tax authorities.

The Issuer has agreed, subject to certain exceptions, in general, to pay additional amounts to Foreign Holders so that the amount received by the holder after Chilean withholding tax will equal the amount that would have been received if no such taxes had been applicable.

Payments of principal

Under the Chilean Income Tax Law, the Foreign Holder will not be subject to withholding tax in respect of payments of principal made by the Issuer with respect to the Notes. However, any other payment to be made by the Issuer (other than interest, premium or principal on the Notes and except for some special exceptions granted by Chilean law and Chilean tax treaties currently in force) will be subject to up to a 35% withholding tax.

Capital Gains

Capital gains realized by a Foreign Holder on the sale or other disposition of the Notes will not be subject to taxes in Chile.

Gift and Inheritance Tax

A Foreign Holder that is not a Chilean national will not be liable for estate, gift, inheritance or similar taxes with respect to its holdings unless Notes held by that Foreign Holder are either (i) deemed to be located in Chile at the time of that Foreign Holder's death, or (ii) purchased or acquired with cash obtained from Chilean sources.

Stamp Tax

Stamp Tax is essentially a documentary tax that applies to documents evidencing any debt obligations such as bond issuances. Accordingly, the issuance of notes is subject to stamp tax at a rate of 0.066% per each month or fraction for the period elapsed between the issuance and the maturity of such notes, calculated over the principal amount of the notes, with a maximum of 0.8% over that principal amount. Accordingly, the Notes will be subject to stamp tax at a rate of 0.8% over their principal amount. If the stamp tax is not paid when due, the Chilean Tax Code imposes inflation adjustments, interests, and penalties whose total amount will depend on the period the stamp tax remains unpaid. Until stamp tax (and applicable adjustment, interest, and penalty) is fully paid, documents subject to stamp tax will not be enforceable before Chilean courts or any Chilean authority and, as a result, the rights of the Foreign Holder regarding the Notes could be deemed as unenforceable.

The Indenture will provide that, subject to specific exceptions and limitations, the Issuer will pay to the Foreign Holders any present or future stamp, court or documentary taxes, charges or levies that arise in Chile from the execution, delivery, enforcement or registration of the Notes or any other document or instrument in relation thereto and has also agreed to indemnify the Holders for any such taxes, charges or similar levies paid by them.

Value Added Tax

Under the Chilean VAT Law, interest charged on financial operations, financial instruments and loans of any kind are VAT exempt. Therefore, under the Chilean VAT Law the issuance of notes, including the Notes, and the payment of interest, implied interest or premium are not subject to VAT.

Certain United States Federal Income Tax Considerations

The following discussion is a summary of certain material U.S. federal income tax consequences of acquiring, owning and disposing of the Notes. Except where otherwise noted, this discussion applies only to beneficial owners of Notes that purchase the Notes in the original offering at the issue price indicated on the cover of this offering memorandum and that hold the Notes as "capital assets" for U.S. federal income tax purposes (generally, property held for investment) within the meaning of Section 1221 of the Code. This discussion is based on the Internal Revenue Code of 1986, as amended (the "*Code*"), its legislative history, existing final, temporary and proposed U.S. Treasury Regulations, administrative pronouncements by the U.S. Internal Revenue Service (the "*IRS*"), and judicial decisions, all as of the date hereof and all of which are subject to change (possibly on a retroactive basis) and to different interpretations. We have not sought any ruling from the IRS regarding the Notes and there can be no assurance that the IRS will not take a different position concerning the tax consequences of the purchase, ownership or disposition of the Notes or that any such position would not be sustained.

This discussion does not purport to address all U.S. federal income tax consequences that may be relevant to a particular holder and you are urged to consult your own tax advisor regarding your specific tax situation. The discussion does not address the tax consequences that may be relevant to holders subject to special tax rules, including, for example:

- insurance companies;
- tax-exempt organizations;
- dealers in securities or currencies;
- traders in securities that elect the mark-to-market method of accounting with respect to their securities holdings;
- banks or other financial institutions;
- partnerships (or other entities treated as partnerships for U.S. federal income tax purposes) and partners therein;
- U.S. Holders (as defined below) whose functional currency for U.S. federal income tax purposes is not the U.S. Dollar;
- real estate investment trusts;
- regulated investment companies;
- grantor trusts;
- U.S. expatriates; or

- Holders that hold the Notes as part of a hedge, straddle, conversion or other integrated transaction.

Further, this discussion does not address the U.S. tax consequences for persons required to accelerate the recognition of any item of gross income with respect to the Notes as a result of such income being recognized on an applicable financial statement, U.S. federal alternative minimum tax consequences of holding the Notes, the U.S. federal income tax on net investment income, U.S. federal taxes other than income taxes or the state, local and non-U.S. tax consequences of acquiring, owning and disposing of the Notes.

As used herein, the term "*U.S. Holder*" means a beneficial owner of a Note that is, for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a corporation, or any other entity taxable as a corporation, created or organized in or under the laws of the United States, any state thereof, or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust if (i) a court within the United States is able to exercise primary supervision over its administration and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) the trust has an election in effect under current U.S. Treasury Regulations to be treated as a U.S. person.

If a partnership (or any other entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds the Notes, the tax treatment of the partnership and a partner in such partnership generally will depend on the status of the partner and the activities of the partnership. Such partner or partnership should consult its own tax advisor as to its consequences of holding the Notes.

Tax Characterization of the Notes

The Issuer intends to take the position that for United States federal income tax purposes the Notes will be characterized as indebtedness of the Issuer. If the IRS successfully asserted that the Notes do not represent debt for United States federal income tax purposes, such Notes might be treated as equity interests in the Issuer and, accordingly, the United States federal income tax consequences of purchasing, holding or disposing of the Notes could materially differ from the consequences discussed herein.

Potential Contingent Payment Debt Instrument Treatment

In certain circumstances the Issuer may be required to make payments on a Note that would change the yield of the Note. See "*Description of the Notes—Change of Control*" and "*Description of the Notes—Optional Redemption*." This obligation may implicate the provisions of Treasury Regulations relating to contingent payment debt instruments ("*CPDIs*"). According to the applicable Treasury Regulations, certain contingencies will not cause a debt instrument to be treated as a CPDI if such contingencies, as of the date of issuance of the debt instrument, are "remote or incidental" or certain other circumstances apply. Although not free from doubt, the Issuer intends to take the position that the Notes are not CPDIs. The Issuer's determination that the Notes are not CPDIs is binding on a U.S. Holder unless such U.S. Holder discloses a contrary position to the IRS in the manner that is required by the applicable Treasury Regulations. The Issuer's determination, however, is not binding on the IRS and if the IRS were to challenge this determination, a holder may be required to accrue income on the Notes that such holder owns in excess of stated interest, and to treat as ordinary income rather than capital gain any income realized on the taxable disposition of such Notes before the resolution of the contingency. If the Notes are not CPDIs but such contingent payments were required to be made, it would affect the amount and timing of the income that a U.S. Holder recognizes.

U.S. Holders are urged to consult their own tax advisors regarding the potential application to the Notes of the CPDI rules and other rules above and the consequences thereof. The remainder of this discussion assumes that the Notes will not be treated as CPDIs.

Payments of Interest and Additional Amounts

It is anticipated, and this discussion assumes, that the Notes will be issued with less than a de minimis amount of original issue discount, if any (as determined under the Code and Treasury Regulations). Therefore, if you are a U.S. Holder, interest (including Additional Amounts) paid to you on a Note, including any amount withheld in respect of any taxes on payments of interest (including Additional Amounts), will be includible in your gross income as ordinary interest income at the time such payments are received or accrued in accordance with your usual method of tax accounting for U.S. federal income tax purposes. In addition, interest on the Notes will be treated as "passive category" foreign source income for U.S. federal income tax purposes for most U.S. Holders. Subject to generally applicable restrictions and conditions (including a minimum holding period requirement), if any foreign income taxes are withheld on interest payments on the Notes (and payments of Additional Amounts), a U.S. Holder will be entitled to a foreign tax credit in respect of any such foreign income taxes. Alternatively, the U.S. Holder may deduct such taxes in computing taxable income for U.S. federal income tax purposes provided that the U.S. Holder does not elect to claim a foreign tax credit for any foreign income taxes paid or accrued for the relevant taxable year. The rules governing the foreign tax credit are complex. You are urged to consult your tax advisor regarding the availability of the foreign tax credit under your particular circumstances.

Sale, Exchange, Retirement or Other Taxable Disposition of Notes

If you are a U.S. Holder, upon the sale, exchange, retirement or other taxable disposition (including a redemption) of a Note you will recognize taxable gain or loss equal to the difference, if any, between the amount realized on the sale, exchange or other taxable disposition, other than any amount attributable to accrued but unpaid stated interest which will be taxable as ordinary income to the extent not previously included in gross income (as described above under "*–Payments of Interest and Additional Amounts*"), and your adjusted tax basis in the Note. Your adjusted tax basis in a Note generally will equal the cost of the Note to you. Any such gain or loss will be capital gain or loss and will generally be treated as long-term capital gain or loss if the Note has been held for more than one year at the time of the sale, exchange, retirement or other taxable disposition of the Note. Certain non-corporate U.S. Holders (including individuals) may be eligible for preferential rates of U.S. federal income tax in respect of long-term capital gains. The deductibility of capital losses is subject to limitations under the Code.

Any gain or loss realized on the sale, exchange or other taxable disposition of a Note generally will be treated as U.S. source gain or loss, as the case may be. As a result, if any such gain is subject to foreign income tax, U.S. Holders may not be able to credit such tax against their U.S. federal income tax liability under the U.S. foreign tax credit limitations of the Code, unless such income tax can be credited (subject to applicable limitations) against U.S. federal income tax due on other income treated as derived from foreign sources. Alternatively, the U.S. Holder may deduct such taxes in computing taxable income for U.S. federal income tax purposes, provided that the U.S. Holder does not elect to claim a foreign tax credit for any foreign income taxes paid or accrued for the relevant taxable year.

U.S. Backup Withholding and Information Reporting

Information reporting generally will apply to payments of principal of, and interest on, Notes, and to proceeds from the sale or redemption of Notes, within the United States, or by a U.S. payor or U.S. middleman, to a U.S. Holder (other than an exempt recipient). Backup withholding will be required on payments made within the United States, or by a U.S. payor or U.S. middleman, on a Note to a U.S. Holder, other than an exempt recipient, if the U.S. Holder fails to furnish its correct taxpayer identification number or otherwise fails to comply with, or establish an exemption from, the backup withholding requirements.

Backup withholding is not an additional tax. You generally will be entitled to credit any amounts withheld under the backup withholding rules against your U.S. federal income tax liability or to receive a refund of the amounts withheld provided the required information is furnished to the IRS in a timely manner.

Foreign Financial Assets Reporting

Certain owners of "specified foreign financial assets" with an aggregate value in excess of US$50,000 on the last day of the taxable year, or US$75,000 at any time during the taxable year generally will be required to file information reports with respect to such assets with their U.S. federal income tax returns. Depending on the holder's circumstances, higher threshold amounts may apply. "Specified foreign financial assets" include any financial accounts maintained by foreign financial institutions, as well as any of the following, but only if they are not held in accounts maintained by certain financial institutions: (i) stocks and securities issued by non-U.S. persons, (ii) financial instruments and contracts held for investment that have non-U.S. issuers or counterparties and (iii) interests in non-U.S. entities. The Notes may be treated as specified foreign financial assets and certain U.S. Holders may be subject to this information reporting regime. Failure to file information reports may subject U.S. Holders to penalties. U.S. Holders should consult their own tax advisors regarding their obligation to file information reports with respect to the Notes.

THIS SUMMARY DOES NOT CONSTITUTE A COMPLETE ANALYSIS OF ALL TAX CONSEQUENCES RELATING TO THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE NOTES. PROSPECTIVE PURCHASERS OF NOTES SHOULD CONSULT THEIR OWN TAX ADVISORS CONCERNING THE CONSEQUENCES OF PURCHASING, OWNING AND DISPOSING OF THE NOTES.

PLAN OF DISTRIBUTION

The Notes

Subject to the terms and conditions set forth in the Purchase Agreement, we have agreed to sell to the Initial Purchasers, and the Initial Purchasers have agreed to purchase from us, severally and not jointly, the principal amount of the Notes set forth opposite its name below:

Initial Purchaser	Principal Amount of the Notes
Goldman Sachs & Co. LLC……………………………………………	US$201,950,000
Citigroup Global Markets Inc....……………………………………….	US$201,950,000
Total……………………………………………………………...	**US$403,900,000**

The Purchase Agreement provides that the obligations of the Initial Purchasers are subject to certain conditions precedent. The Initial Purchasers may offer and sell the Notes through any of their respective affiliates. The Initial Purchasers are offering the Notes subject to its acceptance of the Notes from the Issuer and subject to prior sale. We have agreed to indemnify the Initial Purchasers against certain liabilities pursuant to the Purchase Agreement.

The Initial Purchasers have committed to purchase and pay for all of the Notes being offered hereby. To the extent that the Initial Purchasers do not resell all of the Notes purchased by it in the initial offering, a significant portion of the Notes may be held by a single holder, which could have an adverse effect on the trading price and liquidity of the Notes.

We have been advised that the Initial Purchasers propose to resell the Notes at the offering price set forth on the cover page of this offering memorandum within the United States to QIBs in reliance on Rule 144A and outside the United States in reliance on Regulation S. After the initial offering of the Notes, the price at which the Notes are offered may be changed at any time without notice. This offering of the Notes by the Initial Purchasers is subject to receipt and acceptance of orders and subject to the Initial Purchasers' right to reject any order in whole or in part. Investors in the Notes may be required to pay stamp taxes and other charges in accordance with the laws and practices of the applicable country in addition to the offering price of the Notes (or beneficial interests therein) so acquired.

Notes Not Registered

The Notes have not been and will not be registered under the Securities Act, any state securities laws, or the securities laws of any other jurisdiction. The Notes may not be offered or sold in the United States or to U.S. persons (as defined in Regulation S), except in transactions exempt from, or not subject to, the registration requirements of the Securities Act. Accordingly, the Notes are being offered and sold (i) within the United States or to U.S. persons, only to or for the account of persons that are "qualified institutional buyers" as defined in Rule 144A, and (ii) outside the United States, to persons other than U.S. persons (as defined in Regulation S), in compliance with Regulation S. In addition, the Notes are subject to restrictions on transferability and resale and may not be transferred or resold except as permitted under the Securities Act and applicable state securities laws pursuant to registration thereunder or exemption therefrom.

In connection with sales outside the United States, the Initial Purchasers have agreed that it will not offer, sell or deliver the Notes to, or for the account or benefit of, U.S. persons (i) as part of the distribution at any time or (ii) otherwise until 40 days after the later of the commencement of the offering or the date the Notes are originally issued. The Initial Purchasers will send to each dealer to whom it sells Notes during the 40-day period after the later of the commencement of the offering of the Notes and the closing of this offering, a confirmation or other notice setting forth the restrictions on offers and sales of the Notes within the United States or to, or for the account or benefit of U.S. persons.

In addition, with respect to Notes initially sold pursuant to Regulation S, until 40 days after the later of the commencement of this offering or the date the Notes are originally issued, an offer or sale of Notes within the United States by a dealer that is not participating in the offering may violate the registration requirements of the Securities Act.

New Issue of Securities

The Notes will constitute a new class of securities with no established trading market. An application will be made to the SGX-ST for the listing and quotation of the Notes on the SGX-ST.

The Initial Purchasers have advised us that they intend to make a market in the Notes as permitted by applicable laws and regulations. However, the Initial Purchasers are not obligated to perform any market-making activities with respect to the Notes and, if commenced, any such activities may be discontinued at any time without notice at the discretion of the Initial Purchasers. Accordingly, no assurance can be given as to the liquidity of, or the trading market for, the Notes.

If any active trading market for the Notes does not develop, the market price and liquidity of the Notes may be adversely affected.

No Sales of Similar Securities

We have agreed that, during the period beginning on the date of the Purchase Agreement and continuing to the date that is 90 days after the closing of the offering, we will not, without the prior written consent of the Initial Purchasers, offer, sell or contract to sell, or otherwise dispose of, except as provided in the Purchase Agreement, any securities issued or guaranteed by us that are substantially similar to the Notes.

Stabilization Transactions

In connection with the offering of the Notes, the Initial Purchasers may engage in transactions that stabilize, maintain or otherwise affect the price of the Notes. Specifically, the Initial Purchasers may over allot the offering, creating a syndicate short position. The Initial Purchasers may bid for and purchase the Notes in the open market to cover such syndicate short position or to stabilize the price of the Notes. These activities may stabilize or maintain the market price of the Notes above independent market levels. The Initial Purchasers is not required to engage in these activities and may end these activities at any time and without notice. These transactions may be effected in the over-the-counter market or otherwise.

Settlement

Delivery of the Notes is expected to be made on or about June 15, 2021, which will be the fourth business day following the date of pricing of the Notes (such settlement being referred to as "*T+4*"). Under Rule 15c6-1 of the Exchange Act, trades in the secondary market generally are required to settle in two business days, unless the parties to any such trades expressly agree otherwise. Accordingly, purchasers who wish to trade the Notes prior to the second business day before delivery of the Notes hereunder will be required, by virtue of the fact that the Notes initially will settle in T+4, to specify an alternate settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of the Notes who wish to trade the Notes prior to their date of delivery hereunder should consult their own advisor.

Other Relationships

The Initial Purchasers and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Certain of the Initial Purchasers and their respective affiliates have provided, and may in the future provide, a variety of these services to the Issuer and to persons and entities with relationships with the Issuer, for which they received or will receive customary fees and expenses.

In the ordinary course of their various business activities, the Initial Purchasers and their respective affiliates, officers, directors and employees may purchase, sell or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of the Issuer (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with the Issuer. The Initial Purchasers and their respective affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

In connection with any of the foregoing, the Initial Purchasers and their respective affiliates and subsidiaries may routinely hedge their credit exposure to us or our affiliates, consistent with their customary risk management policies. Typically, the Initial Purchasers and their respective affiliates and subsidiaries would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in securities, including potentially the Notes. Any such short positions could adversely affect future trading prices of Notes.

The Initial Purchasers and their respective affiliates and subsidiaries may also make investment recommendations and/or publish or express independent research views in respect of any securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in securities and instruments, including potentially the Notes.

The Initial Purchasers and their respective affiliates and subsidiaries have received, or may in the future receive, customary fees and commissions for these activities.

Notwithstanding the obligations of the Initial Purchasers under the Purchase Agreement, the Initial Purchasers and their respective affiliates and subsidiaries will be entitled to act with respect to other business in the same manner as if they had not participated in the transactions contemplated hereby and regardless of the effect of such actions on the Notes.

Selling Restrictions

Notice to Prospective Investors in the European Economic Area

Each person in a member state of the EEA (a "*Member State*") of the EEA who receives any communication in respect of, or who acquires any Notes under, the offers to the public contemplated in this offering memorandum will be deemed to have represented, warranted and agreed to and with the Initial Purchasers and the Issuer that: (a) it is a qualified investor within the meaning of the law in that Member State implementing Article 2(1)(e) of the EU Prospectus Directive (Directive 2003/71/EC, as amended) (the "*EU Prospectus Directive*"); (b) it is not a "retail investor" as defined below; and (c) in the case of any Notes acquired by it as a financial intermediary, as that term is used in Article 3(2) of the EU Prospectus Directive, (i) the Notes acquired by it in the offer have not been acquired on behalf of, nor have they been acquired with a view to their offer or resale to, persons in any Member State other than qualified investors, as that term is defined in the EU Prospectus Directive, or in circumstances in which the prior consent of the Initial Purchasers has been given to the offer or resale; or (ii) where Notes have been acquired by it on behalf of persons in any Member State other than qualified investors, the offer of those Notes to it is not treated under the EU Prospectus Directive as having been made to such persons.

The Initial Purchasers have represented and agreed that it has not offered, sold or otherwise made available and will not offer, sell or otherwise make available any Notes to any retail investor in the EEA. For the purposes of this provision the expression "retail investor" means a person who is one (or more) of the following:

- a retail client as defined in point (11) of Article 4(1) of MiFID II;
- a customer within the meaning of IMD, where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or
- not a qualified investor as defined in the EU Prospectus Directive.

Notice to Prospective Investors in the United Kingdom

This offering memorandum is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the EU Prospectus Directive that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "*Order*") or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (each such person being referred to as a "relevant person"). This offering memorandum and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant person should not act or rely on this document or any of its contents.

The Initial Purchasers have represented and warranted that:

- it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of the Securities in circumstances in which Section 21(1) of the FSMA does not apply to us; and

- it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Securities in, from or otherwise involving the UK.

Notice to Prospective Investors in Chile

The offer of the notes is subject to General Rule No. 336 of the CMF. The Notes being offered will not be registered under the Chilean Securities Market Law (*Ley de Mercado de Valores*) in the Securities Registry (*Registro de Valores*) or in the Foreign Securities Registry (*Registro de Valores Extranjeros)* both kept by the CMF and, therefore, the Notes are not subject to the oversight of the CMF. As unregistered securities in Chile, the Issuer is not required to disclose public information about the Notes in Chile. Accordingly, the Notes cannot and will not be publicly offered to persons in Chile unless they are registered in the corresponding Securities Registry. The Notes may only be offered in Chile in circumstances that do not constitute a public offering under Chilean law or in compliance with General Rule No. 336 of the CMF. Pursuant to the Chilean Securities Market Law, a public offering of securities is an offering that is addressed to the general public or to certain specific categories or groups thereof. Considering that the definition of public offering is quite broad, even an offering addressed to a small group of investors may be considered to be addressed to a certain specific category or group of the public and therefore be considered public under applicable law and, as such, subject to registration in Chile. However, pursuant to General Rule No.336 of the CMF, offering of the Notes that meets the conditions described therein shall not be considered public offerings in Chile, including that the offering is addressed to certain "qualified investors" identified as such therein (which in turn are further described in General Rule No. 216, dated June 12, 2008, of the CMF), and shall be exempted from complying with the general rules applicable to public offerings. See "*Notice to Chilean Investors*."

CMF Rule 336 requires the following information to be provided to prospective investors in Chile:

(1) Date of commencement of the offer: June 2, 2021. The offer of the Notes is subject to Rule (*Norma de Carácter General*) No. 336, dated June 27, 2012, issued by the CMF.

(2) The subject matter of this offer are securities not registered with the Securities Registry *(Registro de Valores)*, nor with the Foreign Securities Registry (*Registro de Valores Extranjeros*) both kept by CMF. As a consequence, the Notes are not subject to the oversight of the CMF.

(3) Since the Notes are not registered in Chile, the issuer is not obliged to provide public information about the Notes in Chile.

(4) The Notes shall not be subject to public offering in Chile unless registered with the relevant Securities Registry kept by the CMF.

CMF Rule 336 further requires the following information to be included in the Spanish language:

Aviso a los Inversionistas Chilenos

La oferta de los bonos se acoge a la Norma de Carácter General N°336 de la Comisión para el Mercado Financiero. Los bonos que se ofrecen no están inscritos bajo la Ley N°18.045 de Mercado de Valores en el Registro de Valores o en el Registro de Valores Extranjeros que lleva la Comisión para el Mercado Financiero, por lo que tales valores no están sujetos a la fiscalización de ésta. Por tratarse de valores no inscritos en Chile, no existe obligación por parte del emisor de entregar en Chile información pública respecto de estos valores. Los bonos no podrán ser objeto de oferta pública en Chile mientras no sean inscritos en el Registro de Valores correspondiente. Los bonos solo podrán ser ofrecidos en Chile en circunstancias que no constituyan una oferta pública o cumpliendo con lo dispuesto en la Norma de Carácter General N°336 de la Comisión para el Mercado Financiero. De conformidad con la Ley N°18.045 de Mercado de Valores de Chile, se entiende por oferta pública de valores la dirigida al público en general o a ciertos sectores o a grupos específicos de éste. Considerando lo amplio de dicha definición, incluso una oferta dirigida a un pequeño grupo de inversionistas puede ser considerada como una oferta dirigida a ciertos sectores o a grupos específicos del público y por lo tanto considerada como pública y sujeta a inscripción en Chile bajo la ley aplicable. Sin embargo, en conformidad con lo dispuesto por la Norma de Carácter General N°336 de la Comisión para el Mercado Financiero, los bonos podrán ser ofrecidos privadamente a ciertos "inversionistas calificados," identificados como tal en dicha norma (y que a su vez están descritos en la Norma de Carácter General N° 216 de la Comisión para el Mercado Financiero de fecha 12 de junio de 2008).

La siguiente información se proporciona a potenciales inversionistas de conformidad con la Norma de Carácter General N°336 de la Comisión para el Mercado Financiero:

(1) La oferta de los bonos comienza el 2 de junio de 2021, y se encuentra acogida a la Norma de Carácter General N°336 de la Comisión para el Mercado Financiero, de fecha 27 de junio de 2012.

(2) La oferta versa sobre valores no inscritos en el Registro de Valores o en el Registro de Valores Extranjeros que lleva la Comisión para el Mercado Financiero, por lo tanto, tales valores no están sujetos a la fiscalización de esa Comisión.

(3) Por tratarse de valores no inscritos en Chile, no existe la obligación por parte del emisor de entregar en Chile información pública respecto de los mismos.

(4) Estos valores no podrán ser objeto de oferta pública en Chile mientras no sean inscritos en el Registro de Valores correspondiente.

Notice to Prospective Investors in Brazil

The Notes have not been, and will not be, registered with the Brazilian Securities Commission (*Comissão de Valores Mobiliários*). Any public offering or distribution of the Notes in Brazil, as defined under Brazilian laws and regulations, requires prior registration under Law No. 6,385, of December 7, 1976, as amended, and Instruction No. 400, issued by the CVM on December 29, 2003, as amended. Documents relating to an offering of the Notes by this offering memorandum, as well as information contained in those documents, may not be distributed to the public in Brazil, nor be used in connection with any offer for subscription or sale of the Notes to the public in Brazil. The Notes may not be offered or sold in Brazil, except in circumstances that do not constitute a public offering or distribution under Brazilian laws and regulations.

Persons wishing to offer or acquire the Notes within Brazil should consult with their own counsel as to the applicability of registration requirements or any exemption therefrom.

Notice to Prospective Investors in the Cayman Islands

No invitation, whether directly or indirectly, may be made to the public in the Cayman Islands to subscribe for the Notes unless the issuer is listed on the Cayman Islands Stock Exchange.

Notice to Prospective Investors in Canada

The Notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the Notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this offering memorandum (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the Initial Purchasers are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

Notice to Prospective Investors in the Republic of Colombia

The Notes have not and will not be authorized by the Colombian Superintendency of Finance (*Superintendencia Financiera de Colombia*) and will not be registered under the Colombian National Registry of Securities and Issuers (*Registro Nacional de Valores y Emisores*) or the Colombia Stock Exchange (*Bolsa de Valores de Colombia*), and, accordingly, the Notes will not be offered or sold to persons in Colombia except in circumstances which do not result in a public offering or an exemption therefrom under Colombian law.

Notice to Prospective Investors in Costa Rica

The Notes have not been and will not be registered with Costa Rica's General Superintendency of Securities and, therefore, the Notes are not authorized for public offering in Costa Rica and may not be offered, placed, distributed, commercialized and/or negotiated publicly in Costa Rica, documents relating to the offering of the Notes, as well as information contained therein, may not be offered publicly in Costa Rica, nor be used in connection with any public offering for subscription or sale of the Notes in Costa Rica.

Notice to Prospective Investors in Hong Kong

This offering memorandum has not been approved by or registered with the Securities and Futures Commission of Hong Kong or the Registrar of Companies of Hong Kong. The Notes will not be offered or sold in Hong Kong other than (a) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571) of Hong Kong and any rules made under that Ordinance; or (b) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies Ordinance (Cap. 32) of Hong Kong or which do not constitute an offer to the public within the meaning of that Ordinance. No advertisement, invitation or document relating to the Notes which is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) has been issued or will be issued in Hong Kong or elsewhere other than with respect to Notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance and any rules made under that Ordinance.

Notice to Prospective Investors in Japan

The Notes have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the "*Financial Instruments and Exchange Law*") and the Initial Purchasers have agreed that they will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of

Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

Notice to Prospective Investors in Peru

The Notes and the information contained in this offering memorandum are not being publicly marketed or offered in Peru and will not be distributed or caused to be distributed to the general public in Peru. Peruvian securities laws and regulations on public offerings will not be applicable to the offering of the Notes andtherefore, the disclosure obligations set forth therein will not be applicable to the Issuer or the sellers of the Notes before or after their acquisition by prospective investors. The Notes and the information contained in this offering memorandum have not been and will not be reviewed, confirmed, approved or in any way submitted to the Peruvian National Supervisory Commission of Companies and Securities (*Comisión Nacional Supervisora de Empresas y Valore*s) nor have they been registered under the Securities Market Law (*Ley del Mercado de Valores*) or any other Peruvian regulations. Accordingly, the Notes cannot be offered or sold within Peruvian territory except to the extent any such offering or sale qualifies as a private offering under Peruvian regulations and complies with the provisions on private offerings set forth therein.

Notice to Prospective Investors in Singapore

This offering memorandum has not been, and will not be, registered as a prospectus with the Monetary Authority of Singapore. Accordingly, the Notes may not be offered or sold or caused to be made the subject of an invitation for subscription or purchase, and neither this offering memorandum nor any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Notes may be circulated or distributed, whether directly or indirectly, to any person in Singapore other than (i) to an institutional investor (as defined in Section 4A of the SFA) pursuant to Section 274 of the SFA, (ii) to a relevant person (as defined in Section 275(2) of the SFA) pursuant to Section 275(1) of the SFA, or any person pursuant to Section 275(1A) of the SFA, and in accordance with the conditions specified in Section 275 of the SFA and (where applicable) Regulation 3 of the Securities and Futures (Classes of Investors) Regulations 2018 of Singapore, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the Notes are subscribed or purchased in reliance of an exemption under Section 274 or Section 275 of the SFA, the Notes shall not be sold within the period of six (6) months from the date of the initial acquisition of the Notes, except to any of the following persons:

(i) an institutional investor (as defined in Section 4A of the SFA);
(ii) a relevant person (as defined in Section 275(2) of the SFA); or
(iii) any person pursuant to an offer referred to in Section 275(1A) of the SFA,

unless expressly specified otherwise in Section 276(7) of the SFA or Regulation 37A of the Securities and Futures (Offers of Investments) (Securities and Securities-based Derivatives Contracts) Regulations 2018 of Singapore.

Where the Notes are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

(a) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or
(b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

securities or securities-based derivatives contracts (each term as defined in Section 2(1) of the SFA) of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six (6) months after that corporation or that trust has acquired the Notes pursuant to an offer made under Section 275 of the SFA except:

(1) to an institutional investor or to a relevant person as defined in Section 275(2) of the SFA, or (in the case of such corporation) where the transfer arises from an offer referred to in Section 276(3)(i)(B) of the SFA or (in the case of the such trust) where the offer arises from an offer referred to in Section 276(4)(i)(B) of the SFA;
(2) where no consideration is or will be given for the transfer;
(3) where the transfer is by operation of law;
(4) as specified in Section 276(7) of the SFA; or
(5) as specified in Regulation 37A of the Securities and Futures (Offers of Investments) (Securities and Securities-based Derivatives Contracts) Regulations 2018 of Singapore.

Any reference to the SFA is a reference to the Securities and Futures Act, Chapter 289 of Singapore, and a reference to any term as defined in the SFA or any provision in the SFA is a reference to that term as modified or amended from time to time including by such of its subsidiary legislation as may be applicable at the relevant time.

Notice to Prospective Investors in Switzerland

Securities may not and will not be publicly offered, distributed or redistributed on a professional basis in or from Switzerland only on the basis of a non-public offering, and neither this offering memorandum nor any other solicitation for investments in our securities may be communicated or distributed in Switzerland in any way that could constitute a public offering within the meaning of Articles 652a or 1156 of the Swiss Federal Code of Obligations or of Article 2 of the Federal Act on Investment Funds of March 18, 1994. This offering memorandum may not be copied, reproduced, distributed or passed on to others without the Initial Purchasers' prior written consent. This offering memorandum is not a prospectus within the meaning of Articles 1156 and 652a of the Swiss Code of Obligations or a listing prospectus according to Article 32 of the Listing Rules of the Swiss exchange and may not comply with the information standards required thereunder. We will not apply for a listing of our securities on any Swiss stock exchange or other Swiss regulated market and this offering memorandum may not comply with the information required under the relevant listing rules. The Notes have not been and will not be approved by any Swiss regulatory authority. The Notes have not been and will not be registered with or supervised by the Swiss Federal Banking Commission and have not been and will not be authorized under the Federal Act on Investment Funds of March 18, 1994. The investor protection afforded to acquirers of investment fund certificates by the Federal Act on investment Funds of March 18, 1994 does not extend to acquirers of our securities.

Notice to Prospective Investors in Italy

No application has been or will be made by any person to obtain an authorization from Commissione Nazionale per le Società e la Borsa ("*CONSOB*") for the public offering (*offerta al pubblico*) of the Notes in the Republic of Italy. Accordingly, no may be offered, sold or delivered, nor may copies of this offering memorandum or of any other document relating to the Notes be distributed in the Republic of Italy, except:

(a) to qualified investors (*investitori qualificati*), as defined pursuant to Article 100 of Legislative Decree No. 58 of February 24, 1998, as amended (the "*Financial Services Act*") and Article 34- ter, first paragraph, letter (b) of CONSOB Regulation No. 11971 of May 14, 1999, as amended from time to time ("*Regulation No. 11971*"); or

(b) in any other circumstances where an express exemption from compliance with the rules relating to public offers of financial products (*offerta al pubblico di prodotti finanziari*) provided for by the Financial Services Act and the relevant implementing regulations (including Regulation No. 11971) applies.

Any offer, sale or delivery of the Notes or distribution of copies of this offering memorandum or any other document relating to the Notes in the Republic of Italy must be made:

(a) only by banks, investment firms (*imprese di investimento*) or financial institutions enrolled in the register provided for under article 106 of Italian Legislative Decree No. 385 of 1 September, 1993, as subsequently amended from time to time (the "*Italian Banking Act*"), in each case to the extent duly authorized to engage in the placement and/or underwriting (*sottoscrizione e/o collocamento*) of financial instruments (*strumenti finanziari*) in Italy in accordance with the Italian Banking Act, the Financial Services Act and the relevant implementing regulations;

(b) only to qualified investors (*investitori qualificati*) as set out above; and

(c) in accordance with all applicable Italian laws and regulations, including all relevant Italian securities and tax laws and regulations and any limitations as may be imposed from time to time by CONSOB or the Bank of Italy.

Notice to Prospective Investors in Other Jurisdictions

No action has been taken in any jurisdiction (including the United States or Chile) by the Issuer or the Initial Purchasers that would permit a public offering of the Notes in any jurisdiction where action for that purpose is required. The Notes may not be offered or sold, directly or indirectly, nor may this offering memorandum or any other offering material or advertisements in connection with the offer and sale of the Notes be distributed or published in any jurisdiction, except under circumstances that will result in compliance with the applicable rules and regulations of such jurisdiction. Persons into whose possession this offering memorandum comes are advised to inform themselves about and to observe any restrictions relating to the offering of the Notes and the distribution of this offering memorandum. This offering memorandum does not constitute an offer to purchase or a solicitation of an offer to sell any of the Notes in any jurisdiction in which such an offer or a solicitation is unlawful.

TRANSFER RESTRICTIONS

Because the following restrictions will apply with respect to the resale of the Notes, purchasers are advised to consult legal counsel prior to making any offer, resale, pledge or transfer of the Notes.

The Notes have not been registered under the Securities Act or any state securities laws, and the Notes may not be offered or sold except pursuant to an effective registration statement or pursuant to transactions exempt from, or not subject to, registration under the Securities Act. Accordingly, the Notes are being offered and sold only:

- in the United States to qualified institutional buyers (as defined in Rule 144A) pursuant to Rule 144A under the Securities Act; and

- outside of the United States, to certain persons, other than U.S. persons ("*non-U.S. purchasers*," which term shall include dealers or other professional fiduciaries in the United States acting on a discretionary basis for non-U.S. beneficial owners (other than an estate or trust)), in offshore transactions meeting the requirements of Rule 903 of Regulation S under the Securities Act and in reliance upon Regulation S under the Securities Act. As used herein, the terms "United States" and "U.S. person" have the meanings given to them in Regulation S.

Each purchaser of Notes (other than the Initial Purchasers in connection with the initial issuance and sale of the Notes) and each owner of any beneficial interest therein will be deemed, by its acceptance or purchase thereof, to have represented and agreed as follows:

1. It is purchasing the Notes for its own account or an account with respect to which it exercises sole investment discretion and that it and any such account is either (A) a QIB, and is aware that the sale to it is being made in reliance on Rule 144A or (B) a non-U.S. person that is outside the United States (and is not purchasing for the account of a U.S. person) within the meaning of Regulation S, or a non-U.S. purchaser that is a dealer or other fiduciary as referred to above.

2. It acknowledges that the Notes are being offered in a transaction not involving any public offering in the United States within the meaning of the Securities Act; that the Notes have not been registered under the Securities Act or any securities regulatory authority of any state and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except as set forth below.

3. It shall not resell or otherwise transfer any of such Notes within one year (or such shorter period of time as permitted by Rule 144 under the Securities Act or any successor provision thereunder) after the original issuance of the Notes except (A) to the Issuer or any of its affiliates, (B) inside the United States to a QIB in a transaction complying with Rule 144A under the Securities Act, (C) outside the United States in compliance with Rule 903 or 904 under the Securities Act, (D) pursuant to the exemption from registration provided by Rule 144 under the Securities Act (if available), pursuant to an effective registration statement under the Securities Act, or (E) in accordance with another exemption from the registration requirements of the Securities Act (if available and based upon an opinion of counsel if the Issuer so requests).

4. It agrees that it will give to each person to whom it transfers the Notes notice of any restrictions on transfer of such Notes.

5. If it is a non-U.S. purchaser acquiring a beneficial interest in a Regulation S Global Note, it acknowledges and agrees that (i) until the expiration of the 40-day "distribution compliance period" within the meaning of Regulation S, any offer, sale, pledge or other transfer thereof shall not be made by it in the United States or to, or for the account or benefit of, a U.S. person, except pursuant to Rule 144A to a QIB taking delivery thereof in the form of a beneficial interest in a Rule 144A Global Note, and (ii) that it must exchange its beneficial interest in the Regulation S Global Note for a beneficial interest in a Regulation S Global Note or a Rule 144A Global Note in order to receive payments of interest.

6. It acknowledges that prior to any proposed transfer of Notes in certificated form or of beneficial interests

in a Global Note (in each case other than pursuant to an effective registration statement) the holder of Notes or the holder of beneficial interests in a Global Note, as the case may be, may be required to provide certifications and other documentation relating to the manner of such transfer and submit such certifications and other documentation as provided in the Indenture.

7. It acknowledges that prior to any proposed transfer of Notes, the holder of such Notes may be required to provide certifications and other documentation relating to the manner of such transfer as provided in the Indenture;

8. It understands that:

(i) the following is the form of restrictive legend which will appear on the face of each Global Note, and which will be used to notify transferees of the foregoing restrictions on transfer:

"THIS NOTE HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "*SECURITIES ACT*"), OR ANY OTHER SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, AGREES THAT THIS NOTE OR ANY INTEREST OR PARTICIPATION HEREIN MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) TO THE ISSUER OR ANY OF ITS AFFILIATES, (2) SO LONG AS THIS NOTE IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE SECURITIES ACT ("*RULE 144A*"), INSIDE THE UNITED STATES TO A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A) IN A TRANSACTION COMPLYING WITH RULE 144A, (3) OUTSIDE THE UNITED STATES IN COMPLIANCE WITH RULE 903 OR 904 UNDER THE SECURITIES ACT, (4) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT OR (5) IN ACCORDANCE WITH ANOTHER EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT (AND BASED UPON AN OPINION OF COUNSEL IF THE ISSUER SO REQUESTS). THE HOLDER HEREOF, BY PURCHASING THIS NOTE, REPRESENTS AND AGREES THAT IT WILL NOTIFY ANY PURCHASER OF THIS NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO ABOVE."

The foregoing legend may be removed from this Note only with the consent of the Issuer;" and

(i) the following is the form of restrictive legend which will appear on the face of the Regulation S Global Note and which will be used to notify transferees of the foregoing restrictions on transfer:

"THIS GLOBAL NOTE HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "*SECURITIES ACT*"), AND, ACCORDINGLY, A NON-U.S. PURCHASER ACQUIRING A BENEFICIAL INTEREST IN A REGULATION S GLOBAL NOTE ACKNOWLEDGES AND AGREES (I) THAT NEITHER THIS NOTE NOR ANY INTEREST OR PARTICIPATION HEREIN MAY BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED WITHIN THE UNITED STATES (AS DEFINED IN REGULATION S) OR TO, OR FOR THE ACCOUNT OR BENEFIT OF, A U.S. PERSON (AS DEFINED IN REGULATION S) UNTIL THE EXPIRATION OF THE 40-DAY "DISTRIBUTION COMPLIANCE PERIOD" (AS DEFINED IN REGULATION S), EXCEPT PURSUANT TO RULE 144A ("*RULE 144A*") TO A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A) (A "*QIB*") TAKING DELIVERY THEREOF IN THE FORM OF A BENEFICIAL INTEREST IN A 144A GLOBAL NOTE.

THE FOREGOING LEGEND MAY BE REMOVED FROM THIS NOTE AFTER 40 DAYS BEGINNING ON AND INCLUDING THE LATER OF (A) THE DATE ON WHICH THE NOTES ARE OFFERED TO PERSONS OTHER THAN DISTRIBUTORS (AS DEFINED IN REGULATION S UNDER THE SECURITIES ACT) AND (B) THE ORIGINAL ISSUE DATE OF THIS NOTE."

For further discussion of the requirements (including the presentation of transfer certificates) under the Indenture to effect exchanges or transfers of interest in global notes and certificated notes, see "*Form of Notes, Clearing and Settlement*."

9. It is relying on the information contained in this offering memorandum in making its investment decision

with respect to the Notes. It acknowledges that no representation or warranty is made by the Initial Purchasers as to the accuracy or completeness of such materials. It further acknowledges that neither the Issuer nor the Initial Purchasers nor any person representing us or the Initial Purchasers has made any representation to it with respect to us or the offering or sale of any Notes other than the information contained in this offering circular. It has had access to such financial and other information concerning us and the Notes as it has deemed necessary in connection with its decision to purchase any of the Notes, including any opportunity to ask questions of and request information from us and the Initial Purchasers.

10. It acknowledges that the foregoing restrictions apply to holders of beneficial interests in the Notes, as well as holders of the Notes.

11. It acknowledges that the Trustee will not be required to accept for registration of transfer any Notes acquired by it, except upon presentation of transfer certificates and other related information required under the Indenture.

12. It acknowledges that the Issuer, the Initial Purchaser and others will rely upon the truth and accuracy of the foregoing acknowledgments, representations and agreements and agrees that if any of the acknowledgments, representations or agreements deemed to have been made by its purchase of the Notes is no longer accurate, it shall promptly notify the Issuer and the Initial Purchasers. If it is acquiring the Notes as a fiduciary or agent for one or more investor accounts, it represents that it has sole investment discretion with respect to each such account and it has full power to make the foregoing acknowledgments, representations, and agreements on behalf of each account.

13. It has acknowledged that no assets of a Plan or a non-U.S., governmental or church plan that is subject to Similar Law have been or will be used to acquire the Notes or an interest therein; or (B) its acquisition and holding of such Notes will not constitute or result in a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code or a violation of any applicable Similar Law.

LEGAL MATTERS

Certain legal matters will be passed upon for us by Greenberg Traurig, LLP, special counsel to us as to matters of New York and U.S. federal law and by Barros, Silva, Varela & Vigil Abogados Ltda., special counsel to us as to matters of Chilean law. Certain legal matters will be passed upon for the Initial Purchasers by Milbank LLP, special counsel to the Initial Purchasers as to matters of New York and U.S. federal law and by Carey & Cía. Ltda., special counsel to the Initial Purchasers as to matters of Chilean law.

INDEPENDENT AUDITORS

The Audited Consolidated Financial Statements of the Company as of December 31, 2020 and 2019 and for each of the three years in the period ended December 31, 2020 included in this offering memorandum have been audited by EY Chile, our independent auditors, as stated in their report appearing herein.

INDEPENDENT CONSULTANTS

Appendix A – Independent Engineer Report

Arup Latin America, S.A. has prepared the Independent Engineer Report with respect to the Projects that is included in Appendix A to this offering memorandum. The Independent Engineer Report should be read in its entirety for complete information with respect to the subjects and issues discussed therein. As stated in the Independent Engineer Report, Arup Latin America, S.A. has relied on assumptions regarding circumstances beyond their or our control and not all of these assumptions, which are disclosed in the Independent Engineer Report, are disclosed in the main body of this offering memorandum. Arup Latin America, S.A. believes that the use of such information and assumptions is reasonable for the purposes of the Independent Engineer Report. The Independent Engineer Report has been included in this offering memorandum in reliance upon the conclusions therein and upon Arup Latin America, S.A.'s experience in the review of the design, development, construction and operation of wind farms, including those similar to the Projects.

Appendix B – Independent Market Consultant's Report

Valgesta Energía has prepared the Independent Market Consultant's Report with respect to the Projects that is included in Appendix B to this offering memorandum. The Independent Market Consultant's Report should be read in its entirety for complete information with respect to the subjects and issues discussed therein. As stated in the Independent Market Consultant's Report, Valgesta Energía has relied on assumptions regarding circumstances beyond their or our control and not all of these assumptions, which are disclosed in the Independent Market Consultant's Report, are disclosed in this offering memorandum. Valgesta Energía believes that the use of such information and assumptions is reasonable for the purposes of the Independent Market Consultant's Report. The Independent Market Consultant's Report has been included in this offering memorandum in reliance upon the conclusions therein and upon Valgesta Energía's experience in the review of the development and operation of wind farms, including those similar to the Projects.

LISTING AND GENERAL INFORMATION

An application will be made to the SGX-ST for the listing and quotation of the Notes on the SGX-ST.

The following financial information is available to investors upon written request to the Company or the listing, paying and transfer agent for the Notes:

- The Company's Audited Consolidated Financial Statements as of and for the years ended December 31, 2020, 2019 and 2018; and
- The Company's Unaudited Consolidated Financial Statements as of March 31, 2021 and for the three months ended March 31, 2021 and 2020.

For so long as the Notes are listed on the SGX-ST, copies of the following will be available during the term of the Notes in Singapore at the specified office of the listing, paying and transfer agent for the Notes upon written request to the Company or the listing, paying and transfer agent for the Notes:

- by-laws of the Issuer;
- the Indenture, the Notes and all other Transaction Documents;
- this offering memorandum; and
- copies of the financial statements indicated above.

For fiscal years ended on or after December 31, 2021, and for so long as any of the Notes remain outstanding or listed on the SGX-ST, copies of the Company's annual reports, in English, containing audited consolidated financial statements for the most recent year, will be delivered to the specified offices of, and available with, the paying agent and transfer agent and can be obtained free of charge. See "*Financial Statements—Index*" for the list of financial statements included in this offering memorandum.

In addition to being given to holders via DTC, if and so long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require, copies of such reports and information furnished to the Trustee will also be made available through the SGX-ST at its website (www.sgx.com).

The issuance of the Notes was authorized by the Issuer's members on June 1, 2021. The resolutions also authorized the management to determine the final terms of the issuance of the Notes.

The Issuer is not involved in any litigation, arbitration or administrative proceedings that is material in the context of the issue of the Notes and the Issuer is not aware of any such litigation, arbitration or administrative proceedings, whether pending or threatened. Except as disclosed in this offering memorandum, there has been no significant adverse change in the Issuer's financial or trading position or prospects since December 31, 2021, the date of the latest audited financial statements.

The purchase agreement between the Issuer and the Initial Purchasers, the Notes and the Indenture are governed by the laws of the State of New York, U.S.A. The Collateral Documents are governed by the laws of New York and Chile, as the case may be.

The Notes have been accepted for clearance through the facilities of DTC. The CUSIPs for the Rule 144A Notes and the Regulation S Notes are 46137N AC2 and P5875N AB9, respectively. The ISINs for the Rule 144A Notes and the Regulation S Notes are US46137NAC20 and USP5875NAB93, respectively.

ANNEX A: CERTAIN DEFINITIONS

In this offering memorandum, other than defined terms in the "*Description of Notes*", references to the following terms and abbreviations have the meanings set forth in the chart below (unless the context otherwise requires):

Adjusted PEC:	PEC adjusted for inflation (CPI).
Bankruptcy Law:	Law for the Reorganization and Liquidation of Assets of Companies and Individuals (*Ley de Reorganización y Liquidación de Empresas y Personas*) or Law No. 20,720 of the Ministry of Economy.
Central Bank:	The Central Bank of Chile (*Banco Central de Chile*).
Chile:	Republic of Chile.
CMF:	The Financial Markets Commission (*Comisión para el Mercado Financiero*).
CNE:	National Energy Commission (*Comisión Nacional de Energía*), a governmental consulting agency in charge of developing and coordinating plans, policies and standards for the proper development of the energy industry, overseeing compliance and advising the Chilean government on matters related to energy.
Compendium:	Compendium of Foreign Exchange Regulations of the Central Bank (*Compendio de Normas de Cambios Internacionales*).
Comptroller General:	The Comptroller General *of Chile* (*Contraloría General de la República*).
Contracted Customer:	A customer who is subject to a PPA, whether a Regulated Customer or an Unregulated Customer.
CPI:	Consumer price index (*Índice de Precios al Consumidor*) as reported by the Chilean National Institute of Statistics (*Instituto Nacional de Estadísticas de Chile*).
DisCo:	Utility power distribution companies.
DisCos Short Law:	Chilean Law No. 21,194 of 2019, which reduced the profitability component considered in the tariff-setting process for electric distribution companies, which considered a 10% return over the investment before taxes before the enactment of this law.
Distribution Auction Reform Law:	Law No. 20,805, enacted in 2015. This law modifies the Electricity Law regarding the distribution bidding process for the supply of electricity to Regulated Customers, strengthening CNE's role in the supply of electricity based on grounds of economic efficiency, competition, safety and diversification.
DTC:	The Depository Trust Company.
EEA:	European Economic Area.
Electricity Law:	General Law of Electrical Services (*Ley General de Servicios Eléctricos*, or D.F.L. No. 4/2006 of the Ministry of Economy), as amended.

Environmental Law:	Law No. 19,300, as amended, Constitutional Organic Law on General Basis for the Environment (*Ley Orgánica Constitucional de Bases Generales del Medio Ambiente*) of 1994, enacted in March 1994 and amended in 2010 by Law No. 20,417, and as further amended, which sets up a framework for environmental regulation in Chile
EPC:	Engineering, procurement and construction.
Experts Panel:	An entity (*Panel de Expertos*) created under Short Law I in charge of resolving conflicts arising between companies and the CNE during tariff-setting processes as well as conflicts between the National Electrical Coordinator and companies of the SEN or between companies of the SEN.
GDP:	Gross Domestic Product.
Gigawatt (GW):	One billion watts.
Gigawatt hour (GWh):	One gigawatt of power supplied or demanded for one hour, or one billion watt hours.
In:	Inches.
INE:	Chilean National Institute of Statistics (*Instituto Nacional de Estadísticas*).
Kg/cm2:	Kilogram per square centimeter.
Kilovolt (kV):	One thousand volts.
Kilowatt (kW):	One thousand watts.
Kilowatt hour (kWh):	One kilowatt of power supplied or demanded for one hour, or one thousand watt hours.
km:	Kilometers.
LAP:	Latin America Power Holding B.V., the owner of all but one share in LAP Chile, and ultimate parent of ILAP.
LAP Chile:	Latin America Power S.A., the owner of all but one share in ILAP.
m/s:	Meters per second.
Megawatt (MW):	One million watts.
Megawatt hour (MWh):	One megawatt of power supplied or demanded for one hour, or one million watt hours.
Metro:	Empresa de Transporte de Pasajeros Metro S.A.
Mi:	Mile.
Ministry of Economy:	Ministry of Economy, Development and Tourism (*Ministerio de Economía, Fomento y Turismo*) of Chile.
Ministry of Energy:	Ministry of Energy (*Ministerio de Energía*) of Chile.

Moody's:	Moody's Investors Service.
National Electrical Coordinator:	*Coordinador Independiente del Sistema Eléctrico Nacional*, an autonomous entity in charge of coordinating the efficient operation and dispatch of generation units to satisfy demand pursuant to the Transmission Law.
NCRE:	Non-conventional renewable energy.
NCRE Law:	Law No. 20,257 of 2008, as amended by Law No. 20,698 of 2013, that promotes the use of NCREs and defines the different types of technologies considered to be NCREs. For the period between 2010 and 2014, this law required generation companies to supply 5% of their total contractual obligations entered into after August 31, 2007 with NCREs. The requirement to supply electricity with NCREs will increase by 0.5% annually until 2024, when the requirement will reach 10% of total contractual obligations. A generation company can meet this requirement by developing its own NCRE generation capacity (wind, solar, biomass, geothermal, and small hydro technology), purchasing NCRE certificates locally (similar to carbon bonds) or paying the applicable fines for non-compliance.
Node price:	The energy and capacity prices for the generation and transmission of energy calculated twice per year by the CNE in accordance with section 162 of the LGSE and its complementary regulations.
NPA:	The Note Purchase and Guarantee Agreement, dated as of August 18, 2017, by and among the Company, as issuer, San Juan and Norvind, as guarantors, The Bank of New York Mellon, as offshore collateral agent, registrar and paying agent, and each of the institutional investors named thereto, as amended by the Consent and Amendment to the Note Purchase and Guaranty Agreement, dated as of August 2, 2019.
O&M:	Operation and maintenance.
O&M Agreements:	The Service and Availability Agreement between San Juan and Vestas dated March 25, 2015, as amended on January 29, 2021; and the Service and Availability Agreement between Norvind and Vestas dated April 1, 2013, as amended on December 14, 2016.
Official Gazette:	The Official Gazette (*Diario Oficial*) of Chile.
P(50):	The amount of wind in a year such that the probability that wind in any given future year will exceed such amount is expected to be fifty percent.
P(90):	The amount of wind in a year such that the probability that wind in any given future year will exceed such amount is expected to be ninety percent.
PEC:	The Stabilized Consumer Price (*Precio Estabilizado a Clientes*), created by the Tariff Stabilization Law.
PEC Receivables:	Energy tariff receivables created by the Tariff Stabilization Law and payable by DisCos in the Republic of Chile.
PNPs:	Average node purchase price (*precio de nudo promedio*) that Regulated Customers pay to a specific DisCo for the supply of electricity during the

	applicable Tariff Period, and which is a weighted average of the PNLPs payable by such DisCo, taking into account certain other factors
PNLPs:	Purchase prices for electricity (*precios de nudo de largo plazo*) payable by the DisCos to electricity generation companies under a PPA awarded pursuant to a public tender (together with any adjustments).
PPAs:	Power purchase agreements.
Projects:	Collectively, the San Juan Project and the Totoral Project, owned and developed by San Juan and Norvind, respectively.
Regulated Customers:	Consumers in Chile with a connected capacity equal to or less than 5,000 kW (5 MW)); principally residential and small industrial and commercial customers.
S&P:	S&P Global Ratings.
Securities Market Law:	Law No. 18,045 of 1981, of Chile, on the Securities Market (*Ley de Mercado de Valores*), as amended.
Securities Registry:	The Registry of issuer of publicly traded securities in Chile (*Registro de Valores*), carried out by the CMF.
SEN:	The National Electric System (*Sistema Eléctrico Nacional*) for transmission in Chile, into which the SIC and the SING merged on November 21, 2017, consisting in a 3,100 km electrical interconnection system covering the majority of Chile's territory, from the city of Arica in the north, to the Island of Chiloé in the south, and composed by a set of electrical interconnected installations.
Short Law I:	Law No. 19,940, enacted in 2004 as an amendment to the Electricity Law (*Ley Corta 1*). This law introduced (i) new regulation applicable to the transmission system, the development of the transmission system and the rates transmission facility owners can charge to users of the system; (ii) new regulation on tariffs in middle and isolated systems, such as those in the regions of Aysén and Magallanes; (iii) an Experts Panel to resolve controversies between authorities and companies and among companies the electricity sector; and (iv) new regulation with respect to reliability and ancillary services.
Short Law II:	Law No. 20,018, enacted in 2005 as an amendment to the Electricity Law (*Ley Corta 2*). This law requires that all new long-term PPAs between generation companies and DisCos for the supply of Regulated Customers be the result of bids via open, competitive and transparent auction processes. These new long-term PPAs can have tenors of up to 15 years. In regard to the capacity product (reliability payment), the long-term PPAs incorporate the capacity price fixed by the CNE and are indexed to CPI and other relevant indices.
SIC:	Central Interconnected Electricity System (*Sistema Interconectado Central*), Chile's main interconnected power grid, that covered most of Chile except the north (covered by the SING) and the extreme south of the country (Aysén and Magallanes regions) before being merged with the SING into the SEN on November 21, 2017.
SING:	Northern Interconnected Electricity System (*Sistema Interconectado del Norte Grande*), a grid that covered the Northern regions of Chile (regions of Tarapacá,

	Antofagasta and Arica and Parinacota) before being merged with the SIC on November 21, 2017.
spot market:	The wholesale electricity market in which power generation companies purchase electricity as necessary to fulfill their contractual electricity sales requirements or sell electricity to other generation companies when their electricity production exceeds their contractual requirements. Electricity trades on the spot market are made at spot prices set hourly by the National Electrical Coordinator based on the marginal cost of production of the last power generation facility dispatched.
Substation:	A part of an electrical generation, transmission and distribution system, which, among other functions, transforms voltage from high to low or from low to high.
Superintendency of Electricity:	Chilean Superintendency of Electricity and Fuels (*Superintendencia de Electricidad y Combustibles*), a governmental entity in charge of supervising the Chilean electricity market. The SEC sets and enforces the technical standards of the system and monitors and enforces compliance with the law and regulations related to energy matters, including all rules related to security and service quality. It is also in charge of processing electric concessions and easements related thereto for hydroelectric facilities, transmission lines, and distribution networks.
Tariff Decree:	A decree issued by the Ministry of Energy semi-annually for each Tariff Period on May 15 and November 15 of each year, setting tariffs payable by Regulated Customers as well as the PNLPs. Tariffs, PPA prices and other amounts set out in Tariff Decrees are based on calculations based on preliminary and definitive technical reports prepared semi-annually by the CNE in the month leading up to the issuance of each Tariff Decree.
Tariff Period:	The six-month period from July 1 to December 31, with respect to each Tariff Decree required to be issued on May 15, and the six-month period from January 1 to June 30, with respect to each Tariff Decree required to be issued on November 15 of the previous year.
Tariff Stabilization Framework:	Together, the Tariff Stabilization Law and the Tariff Stabilization Resolution.
Tariff Stabilization Law:	The Tariff Stabilization law, law No. 21,185, which established the transitory Tariff Stabilization Mechanism (*Ley 21.185 - Crea un mecanismo transitorio de estabilización de precios de la energía eléctrica para clientes sujetos a regulación de tarifas*), together with subsequent resolutions No. 72, 114 and 340 of 2020, issued by the CNE, which created a Tariff Stabilization Mechanism for Regulated Customers.
Tariff Stabilization Mechanism:	The tariff stabilization mechanism established by the Tariff Stabilization Law, with respect to tariffs that DisCos are permitted to charge their Regulated Customers.
Tariff Stabilization Resolution:	Resolution No. 72, issued by the CNE on March 5, 2020, which implements the Tariff Stabilization Law, and amended by Resolution No. 114, issued on April 9, 2020 and by Resolution No. 340, issued on September 14, 2020.
SII:	Chilean Internal Revenue Service (*Servicio de Impuestos Internos*).

take-and-pay:	An agreement in which the buyer becomes legally obligated to pay for the goods or services purchased upon delivery or upon the buyer's agreement to take delivery.
take-or-pay:	An agreement where one party agrees to either buy certain goods or services from the other party on a certain date or to pay for them even if that party does not need them on that date.
Transelec:	Transelec S.A., a Chilean closely held stock corporation (*sociedad anónima cerrada*) subject to disclosure rules applicable to publicly traded stock corporations.
Transmission Law:	Law No. 20,936, published on July 20, 2016 that amended the Electricity Law, principally with regard to the existing regulation on transmission activities in Chile, created the National Electrical Coordinator and the National Electrical Grid, and unified valorization and expansion plans for each transmission system, among other things.
Treasury:	The Office of the Treasurer (*Tesorería General de la República de Chile*).
UF:	*Unidad de Fomento*, a Chilean inflation-indexed Peso-denominated monetary unit.
Unregulated Customers:	Chilean consumers of electricity consumers whose connected capacity exceeds 5,000 kW (5 MW).
U.S.:	The United States of America.
U.S. CPI:	United States Consumer Price Index.
U.S. Dollar ($):	The official currency of the U.S.
UF:	*Unidades de Fomento*, an inflation-indexed Peso-denominated monetary unit calculated and published by the Central Bank with a value in Pesos that is adjusted daily to reflect changes in the official CPI calculated by the INE, published monthly in the Official Gazette, and adjusted in monthly cycles.
VAD:	The Value Added-In Distribution Tariff.
Watt:	The basic unit of electrical power, equivalent to one joule of energy per second.

FINANCIAL STATEMENTS

Index

LATIN AMERICA POWER

Unaudited Interim Consolidated Financial Statements as of March 31, 2021, and for the three-month periods ended March 31, 2021 and 2020

Interim Consolidated Statements of Financial Position as of March 31, 2021 (unaudited) and December 31, 2020 (audited)

Thousands of US Dollars (ThUS$)	Note	March 31, 2021	December 31, 2020
Assets			
Current assets			
Cash and cash equivalents	6	2,639	7,363
Trade and other current receivables	12	7,188	10,565
Accounts receivable from related entities	15	3,728	3,836
Inventory	9	93	63
Total current assets		**13,648**	**21,827**
Non-current assets			
Trade and other current receivables, non-current	12	12,063	11,742
Intangible assets other than goodwill	8	489	491
Property, plant and equipment	7.a	389,975	395,264
Deferred tax assets	18.a	37,791	36,098
Total non-current assets		**440,318**	**443,595**
Total assets		**453,966**	**465,422**
Equity and liabilities			
Current liabilities			
Other current financial liabilities	14	12,175	16,404
Trade and other payables	13	13,877	10,288
Accounts payable to related entities	15	4,889	4,902
Lease liabilities	10	362	362
Total current liabilities		**31,303**	**31,956**
Non-current liabilities			
Other non-current financial liabilities	14	372,501	378,811
Provisions	16	53,226	52,885
Lease liabilities	10	11,562	11,652
Total non-current liabilities		**437,289**	**443,348**
Total liabilities		**468,592**	**475,304**
Equity			
Paid-in capital	19	89,801	89,801
Retained earnings (accumulated losses)		(99,683)	(90,094)
Result for the period		(4,744)	(9,589)
Equity attributable to the owners of the Parent		**(14,626)**	**(9,882)**
Non-controlling interests		-	-
Total equity		**(14,626)**	**(9,882)**
Total equity and liabilities		**453,966**	**465,422**

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Unaudited Interim Consolidated Statements of Comprehensive Income for the three-months periods ended March 31, 2021 and 2020

Thousands of US Dollars (ThUS$)	Note	March 31,	
		2021	2020
Profit or loss			
Revenue	20	15,617	20,920
Cost of sales	21	(14,918)	(16,637)
Gross profit		**699**	**4,283**
Administrative expenses	22	(458)	(430)
Operating profit		**241**	**3,853**
Finance income		-	15
Finance expenses	23	(6,263)	(6,425)
Foreign exchange differences		(415)	(789)
Loss before taxes		**(6,437)**	**(3,346)**
Income tax benefit (expense)	18.b	1,693	(524)
Loss for the period		**(4,744)**	**(3,870)**
Attributable to:			
Owners of the Parent		(4,744)	(3,870)
Non-controlling interests		-	-
Other comprehensive income (loss)		-	-
Total comprehensive loss for the period, net of tax		**(4,744)**	**(3,870)**
Attributable to:			
Owners of the Parent		**(4,744)**	**(3,870)**
Non-controlling interests		**-**	**-**

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Unaudited Interim Consolidated Statements of Changes in Equity for the three-month periods ended March 31, 2021 and 2020

Thousands of US dollars (ThUS$)	Paid-in capital	Retained earnings (accumulated losses)	Result for the period	Total equity
Opening balance 01-01-2021	**89,801**	**(90,094)**	**(9,589)**	**(9,882)**
Changes in equity				
Comprehensive Income				
Loss for the period	-	-	(4,744)	**(4,744)**
Appropriation of results	-	(9,589)	9,589	-
Total changes in equity	**-**	**(9,589)**	**4,845**	**(4,744)**
Closing balance 31-03-2021	**89,801**	**(99,683)**	**(4,744)**	**(14,626)**

Thousands of US dollars (ThUS$)	Paid-in capital	Retained earnings (accumulated losses)	Result for the period	Total equity
Opening balance 01-01-2020	**93,001**	**(70,964)**	**(19,130)**	**2,907**
Changes in equity				
Comprehensive Income				
Loss for the period	-	-	(3,870)	**(3,870)**
Appropriation of results	-	(19,130)	19,130	-
Total changes in equity	-	**(19,130)**	**15,260**	**(3,870)**
Closing balance 31-03-2020	**93,001**	**(90,094)**	**(3,870)**	**(963)**

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Unaudited Interim Consolidated Statements of Cash Flows for the three-month periods ended March 31, 2021 and 2020

Thousands of US Dollars (ThUS$)	March 31,	
	2021	2020
Cash flows from operating activities		
Loss before taxes	**(6,437)**	**(3,346)**
Adjustments to reconcile profit/loss to net cash flow:		
Depreciation	5,330	5,754
Foreign exchange differences	415	789
Finance expenses	6,263	6,425
Changes in assets and liabilities:		
Inventory	(30)	-
Trade and other account receivables	3,056	(5,825)
Other current assets	-	(66)
Trade payables and other current liabilities	3,589	1,093
Other non-financial assets and liabilities	(463)	(193)
Account receivable and payable with related entities	95	-
Interest paid	(10,727)	(11,008)
Net cash flow generated by (used in) operating activities	**1,091**	**(6,377)**
Cash flows from investment activities		
Acquisition of property, plant, equipment and intangibles	-	(14)
Net cash flow used in investment activities	**-**	**(14)**
Cash flows from financing activities		
Payment of principal portion of lease liabilities	(90)	(86)
Repayment of borrowings	(5,725)	(4,259)
Net cash flow used in financing activities	**(5,815)**	**(4,345)**
Net increase (decrease) in cash and cash equivalents	**(4,724)**	**(10,736)**
Opening balance of cash and cash equivalents	**7,363**	**18,428**
Closing balance of cash and cash equivalents	**2,639**	**7,692**

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

1. Reporting entity

Inversiones Latin America Power Ltda. (hereinafter "ILAP" or the "Company"), is a limited liability company incorporated by public deed dated June 14, 2013, under Notarial Record No. 10077-2013 whose business purpose is: a) making investments in all kinds of assets, whether movable or immovable, tangible or intangible, including the acquisition of shares or rights in partnerships, debentures, bonds, commercial papers, and all kinds of securities, and investment instruments, as well as the administration of said investments and its returns; and b) in general, any other investment activity.

Inversiones Latin America Power Ltda. is part of Latin América Power Group ("LAP Group") and is directly controlled by Latin América Power S.A., which is a closely-held corporation domiciled in Chile. Latin America Power S.A. is controlled by Latin America Power Holding B.V., a company incorporated on February 20, 2012 and domiciled in the Netherlands, which is the ultimate parent of the LAP Group (hereinafter, along with all its subsidiaries, the "LAP Group").

2. Significant accounting policies

2.1 Basis of preparation

a) Statement of compliance and basis of presentation

These unaudited interim consolidated financial statements include the interim consolidated statements of financial position as of March 31, 2021 (unaudited) and December 31, 2020 (audited), and the related unaudited interim consolidated statements of comprehensive income, changes in equity and cash flows for the three-month periods ended March 31, 2021 and 2020 of the Company and its subsidiaries (the "Group"). These unaudited interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board (IASB) and fairly present the financial position of the Group as of March 31, 2021 and the results of its operations and its cash flows for the three-month periods ended March 31, 2021 and 2020.

Note 2.2 describes main accounting policies adopted in the preparation of these unaudited interim consolidated financial statements. These policies have been defined based on IFRS in effect as of March 31, 2021, and have been consistently applied in all periods presented in these unaudited interim consolidated financial statements.

As of March 31, 2021, the Group presents a negative working capital of ThUS$ 17,655 (ThUS$ 10,129 as at December 31, 2020). Management expects the Company to generate sufficient cash flows from its normal business operations to meet its obligations and, in addition, it expects to count on the financial support of LAP Group. Additionally, the Group is currently searching for different alternatives to monetize the non-current accounts receivables related to the Price Stabilization Law (PEC) (see Note 12)). These financial statements were prepared on the basis of the continuity of the Company as a going concern.

The financial statements are presented in thousands of US dollars ("ThUS$"), unless otherwise stated. US dollar is functional currency of the Company and its subsidiaries.

These consolidated financial statements have been approved and authorized by Management for issuance on June 1, 2021.

b) Basis of measurement

The consolidated financial statements have been prepared on a historical cost basis.

c) Basis of consolidation

The ILAP Group considers that it controls an investee when is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if it has all the following: (a) power over the investee; (b) exposure, or rights, to variable returns from its involvement with the investee; and (c) the ability to use its power over the investee to affect its returns.

In the case of the Group, the power over its subsidiaries is derived from the possession of practically total of the voting rights.

The Group re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of are included in the consolidated financial statements from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income ("OCI") are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction.

If the Group loses control over a subsidiary, it derecognizes the related assets (including goodwill), liabilities, non-controlling interest and other components of equity, while any resultant gain or loss is recognized in profit or loss. Any investment retained is recognized at fair value.

The following subsidiaries are included in these consolidated financial statements:

Country of incorporation	Entity	Participation	Status
Chile	Norvind S.A. ("Norvind")	99,99%	Operating
Chile	San Juan S.A. ("San Juan")	99.999998%	Operating

San Juan S.A. operates Parque Eólico San Juan (193,2 MW of installed capacity), located in the province of Coquimbo, IV Region, Chile, since March 2017.

Norvind S.A. operates Parque Eólico Totoral (46 MW of installed capacity), located in Canela, Coquimbo Region, since January 2010.

Transactions eliminated on consolidation

Intra-group balances and transactions, and any unrealized income and expenses arising from intra-group transactions, are eliminated in preparing the consolidated financial statements. Unrealized gains arising from transactions with equity-accounted investees are eliminated against the investment to the extent of the Group's interest in the investee. Unrealized losses are eliminated in the same way as unrealized gains, but only to the extent that there is no evidence of impairment.

2.2 Summary of significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, except as otherwise stated, and have been applied consistently by all entities consolidated within the Group.

a) New IFRS pronouncements in effect since January 1, 2020

The Company applied certain standards, interpretations and amendments for the first time, which are effective for annual periods beginning on or after January 1, 2020. The standards, interpretations and amendments to IFRS that went into effect as of the date of the financial statements, as well as their nature and impact, are detailed below.

	Standards and Interpretations	Date of mandatory application
Conceptual framework	Conceptual Framework (revised)	January 1, 2020

Conceptual Framework (revised)

The IASB issued the Conceptual Framework (revised) in March 2018. It incorporates new concepts, provides updated definitions and recognition criteria for assets and liabilities, and clarifies some important concepts.

Changes to the Conceptual Framework may affect the application of IFRS when no standard applies to a particular transaction or event. The revised Conceptual Framework goes into effect for periods that begin on or after January 1, 2020. These amendments had no impact on the consolidated financial statements of the Group.

	Amendments	Date of mandatory application
IFRS 3	Definition of a Business	January 1, 2020
IAS 1 e IAS 8	Definition of Material	January 1, 2020
IFRS 9, IAS 39 e IFRS 7	Interest Rate Benchmark Reform	January 1, 2020
IFRS 16	COVID-19-Related Rent Concessions	January 1, 2020

IFRS 3 Business Combinations – Definition of a Business

The IASB issued amendments to the definition of a business in IFRS 3 *Business Combinations* to help entities determine whether or not an acquired set of activities and assets is a business. The IASB clarifies the minimum requirements to define a business; eliminates assessment of whether market participants are able to replace any missing elements; includes guidance to assist entities in assessing whether an acquired project is substantive; narrows the definition of a business and of products; and introduces an optional fair value concentration test.

The amendments must be applied to the business combinations or asset acquisitions for which the acquisition date is on or after the beginning of the first annual reporting period that begins on or after January 1, 2020. Therefore, entities do not have to revisit transactions occurred in prior periods. Early application is permitted and must be disclosed.

These amendments had no impact on the consolidated financial statements of the Group, but may impact future periods should the Group enter into any business combinations.

IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors - Definition of Material

In October 2018, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors,* to align the definition of "material" in all standards and clarify certain aspects of the definition. The new definition establishes that information is material if omitting, misstating or obscuring it could reasonably be expected to influence the decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity. The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to the Group.

IFRS 9, IAS 39 and IFRS 7 Interest Rate Benchmark Reform

In September 2019, the IASB issued amendments to IFRS 9, IAS 39, and IFRS 7, finalizing Phase I of the project to address the effects of the reform to interbank offered rates (IBORs) in financial reporting. The amendments provide a number of reliefs, which apply to all hedging relationships that are directly affected by interest rate benchmark reform. A hedging relationship is affected if the reform gives rise to uncertainty about the timing and/or amount of benchmark-based cash flows of the hedged item or the hedging instrument. These amendments have no impact on the consolidated financial statements of the Group.

IFRS 16 COVID-19-Related Rent Concessions

In May 2020, the IASB issued an amendment to IFRS 16 Leases ("IFRS 16") to provide relief to lessees applying IFRS 16 guidance in connection with lease modifications and rent concessions that occur as a direct consequence of COVID-19 pandemic. The amendment does not apply to lessors.

The amendments provide relief to lessees from applying IFRS 16 guidance on lease modification accounting for rent concessions arising as a direct consequence of the Covid-19 pandemic. As a practical expedient, a lessee may elect not to assess whether a Covid-19 related rent concession from a lessor is a lease modification. A lessee that makes this election accounts for any change in lease payments resulting from the Covid-19 related rent concession the same way it would account for the change under IFRS 16, if the change were not a lease modification.

The amendment applies to annual reporting periods beginning on or after 1 June 2020. Earlier application is permitted. This amendment had no impact on the consolidated financial statements of the Group.

b) Foreign currency

Transactions in a foreign currency (currency different from the functional currency) are converted into the functional currency of the Company at the dates of the transactions (the main non-dollar currency used by the Company is the Chilean peso). Losses and profits resulting from the settlement of balances related to these transactions and from conversion, at the closing rate, of monetary assets and liabilities denominated in a foreign currency and existing at the reporting date, are recognized in the income statement within the "Exchange differences" heading.

The exchange rates of the Chilean peso (CLP) as of March 31st, 2021 and 2020 and December 31st, 2020 are as follows:

Date	Currency	Exchange Rate
March 31, 2021	USD 1	CLP 721.82
March 31, 2020	USD 1	CLP 852.03
December 31, 2020	USD 1	CLP 710.95

c) Business combinations, goodwill and acquisition of non-controlling interests

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at acquisition date fair value, and the amount of any non-controlling interests in the acquiree. For each business combination, the Group elects whether to measure the non-controlling interests in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

Goodwill is initially measured at cost (being the excess of the aggregate of the consideration transferred and the amount recognized for non-controlling interests and any previous interest held over the net identifiable assets acquired and liabilities assumed). If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group re-assesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognized at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognized in profit or loss.
After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a cash-generating unit (CGU) and part of the operation within that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the cash-generating unit retained.

A contingent liability recognised in a business combination is initially measured at its fair value. Subsequently, it is measured at the higher of the amount that would be recognised in accordance with the requirements for provisions in IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* or the amount initially recognised less (when appropriate) cumulative amortisation recognised in accordance with the requirements for revenue recognition.

d) Cash and cash equivalents

Cash and cash equivalents include cash in hand and demand deposits in financial institutions. They also include other short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. An investment normally qualifies as a cash equivalent when it has a maturity of less than three months from the date of acquisition.

e) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity.

The Company´s non-derivative financial instruments comprise mainly trade and other receivables, cash and cash equivalents, loans and borrowings, and trade and other payables.

(i) Financial assets

Financial assets are classified, at initial recognition, as subsequently measured at amortized cost, fair value through OCI, and fair value through profit or loss. The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing them. With the exception of trade receivables that do not contain a significant financing component, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs. Trade receivables that do not contain a significant financing component are measured at the transaction price determined under IFRS 15.

In order for a financial asset to be classified and measured at amortized cost or fair value through OCI, it needs to give rise to cash flows that are 'solely payments of principal and interest ("SPPI")' on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Company's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.
Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the market place (regular way trades) are recognized on the trade date, i.e., the date that the Company commits to purchase or sell the asset.

For purposes of subsequent measurement, financial assets are generally classified in four categories:

- Financial assets at amortized cost (debt instruments);
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments);
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments); and
- Financial assets at fair value through profit or loss.

The Company has currently only instruments classified to the categories of financial assets at amortized cost and minor financial assets at fair value through profit or loss. All derivative instruments are designated hedging instruments in hedge relationships and are accounted in accordance with the policy applicable for hedge accounting described further in this Note.

Financial assets at amortized cost (debt instruments)

The Company measures financial assets at amortized cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows, and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets at amortized cost are subsequently measured using the effective interest ("EIR") method and are subject to impairment. Gains and losses are recognized in profit or loss when the asset is derecognized, modified or impaired.

The Company's financial assets at amortized cost includes mainly trade and other receivables, including those due from related parties.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading, financial assets designated upon initial recognition at fair value through profit or loss, or financial assets mandatorily required to be measured at fair value. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments. Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at fair value through profit or loss, irrespective of the business model.

Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value recognized in the statement of profit or loss.

A derivative embedded in a hybrid contract, with a financial liability or non-financial host, is separated from the host and accounted for as a separate derivative if: the economic characteristics and risks are not closely related to the host; a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and the hybrid contract is not measured at fair value through profit or loss. Embedded derivatives are measured at fair value with changes in fair value recognized in profit or loss. Reassessment only occurs if there is either a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required or a reclassification of a financial asset out of the fair value through profit or loss category.

A derivative embedded within a hybrid contract containing a financial asset host is not accounted for separately. The financial asset host together with the embedded derivative is required to be classified in its entirety as a financial asset at fair value through profit or loss.

Derecognition

A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognized (i.e., removed from the Group's consolidated statement of financial position) when:

- The rights to receive cash flows from the asset have expired or
- The Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Company has transferred substantially all the risks and rewards of the asset, or (b) the Company has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

Impairment of financial assets

The Company recognizes an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognized in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12-months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Company applies a simplified approach in calculating ECLs. Therefore, the Company does not track changes in credit risk, but instead recognizes a loss allowance based on lifetime ECLs at each reporting date. The Company has established a provision matrix that is based on its historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Company generally considers a financial asset in default when contractual payments are 12 months past due. However, in certain cases, the Company may also consider a financial asset to be in default when internal or external information indicates that the Company is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Company. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

(ii) inancial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, trade payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognized initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowings including bank overdrafts and derivative financial instruments.

The measurement of financial liabilities depends on their classification, as described below:

<u>Financial liabilities at fair value through profit or loss</u>

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Company that are not designated as hedging instruments in hedge relationships as defined by IFRS 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognized in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in IFRS 9 are satisfied. The Company has not designated any financial liability as at fair value through profit or loss.

<u>Loans and borrowings and trade payables</u>

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortized cost using the EIR method. Gains and losses are recognized in profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

Amortized cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortization is included as finance costs in the statement of profit or loss. This category generally applies to interest-bearing loans and borrowings.

A financial liability is derecognized when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognized in the statement of profit or loss.

f) Property, plant and equipment

Land, construction in progress, plant and equipment are stated at cost, net of accumulated depreciation and accumulated impairment losses, if any. Such cost includes the cost of replacing part of the plant and equipment and borrowing costs for long-term construction projects if the recognition criteria are met. When significant parts of plant and equipment are required to be replaced at intervals, the Group depreciates them separately based on their specific useful lives. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the plant and equipment as a replacement if the recognition criteria are satisfied. All other repair and maintenance costs are recognized in profit or loss as incurred.

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets, as follows:

Property, plant and equipment	Years
Towers and Control Rooms	25
Wind turbines	20
Technical facilities	20

Land is not depreciated.

An item of property, plant and equipment and any significant part initially recognized is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement or profit or loss when the asset is derecognized.

The residual values, useful lives and methods of depreciation of property, plant and equipment are reviewed at each financial year end and adjusted prospectively, if appropriate.

The present value of the expected cost for the decommissioning of an asset after its use is included in the cost of the respective asset if the recognition criteria for a provision are met. Refer to significant accounting judgements, estimates and assumptions (Note 3) and provisions (Note 16) for further information about the recognized decommissioning provision.

g) Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale are capitalized as part of the cost of the asset. All other borrowing costs are expensed in the period in which they occur. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

h) Impairment of non-financial assets

The Group assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Group estimates the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's or cash generating unit's ("CGU") fair value less costs of disposal and its value in use. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets.

When the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs of disposal, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model is used. The models that the Group uses are based on the discounted cash flows methodology. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded companies or other available fair value indicators.

Each of the CGU's recoverable amounts which are subject to impairment test periodically, are estimated through the fair value less costs of disposal according to IFRS 13 *Fair Value measurement* and compared with the recoverable amount of the respective CGU. The Group bases its impairment calculation on detailed budgets and forecast calculations, which are prepared separately for each of the Group's CGUs to which the individual assets are allocated. These budgets and forecast calculations generally cover a period equal to estimated useful lives of the respective assets (power plants).

Impairment losses of continuing operations are recognized in the statement of profit or loss in expense categories consistent with the function of the impaired asset.

For assets excluding goodwill, an assessment is made at each reporting date to determine whether there is an indication that previously recognized impairment losses no longer exist or have decreased. If such indication exists, the Group estimates the asset's or CGU's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in the statement of profit or loss unless the asset is carried at a revalued amount, in which case, the reversal is treated as a revaluation increase.

Goodwill is tested for impairment annually as at 31 December and when circumstances indicate that the carrying value may be impaired.

Impairment is determined for goodwill by assessing the recoverable amount of each CGU (or group of CGUs) to which the goodwill relates. When the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognized. Impairment losses relating to goodwill cannot be reversed in future periods.

Intangible assets with indefinite useful lives are tested for impairment annually as at 31 December at the CGU level, as appropriate, and when circumstances indicate that the carrying value may be impaired.

i) Provisions

A provision is recognized, as a result of a past event, if ILAP Group has a present (legal or constructive) obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. When the effect of the time value of money is significant, the amount of the provision is the present value of expenses expected to be incurred to pay the obligation.

If the ILAP Group has an evidence that a provision can be reimbursed, e.g. those cases covered by an insurance policy, the reimbursement is recognized separately as an asset only when it is effectively probable that reimbursement will be received.

Every six months, the legal department of the Company meets its legal counsel and analyzes the potential liabilities or claims that may be received by the Company. If it is determined that the probability of an adverse outcome is more than 50%, a provision is recognized and measured based on the best available estimate.

j) Revenue and expense recognition

<u>Revenue</u>

Revenue is earned from the production and sale of energy (electricity) and capacity from the Group's generation plants. Revenue is recognized upon the transfer of control of promised goods or services to customers in an amount that reflects the consideration to which the Group is expected to be entitled in exchange for those goods or services. Revenue is recorded net of any taxes assessed on and collected from customers.

The Company provides the service of energy and capacity supply to unregulated (free) and regulated customers. The revenues are recognized based on the physical delivery of energy and capacity. The services are satisfied over time as the client receives simultaneously and consumes the benefits provided by the Company. Consequently, the Company recognizes the revenue for these service contracts grouped over time instead of at a point of time.

Revenue from sales to regulated customers (distribution companies) and free customers (usually industrial clients) are recorded on the basis of physical delivery of energy and capacity, in accordance with long-term power purchase agreements (“PPAs”). Revenues from energy and capacity sales on the spot market are recorded on the basis of physical delivery, to other generating companies, at the marginal cost of energy and capacity. The spot market by respective laws is organized through Dispatch Centers (CEN) where the surpluses and deficits of energy and capacity are settled. Energy and capacity surpluses are recorded as revenues and deficits are recorded as cost of sales within the consolidated statement of profit or loss.

Revenue from generation contracts is recognized using an output method, as energy and capacity delivered best depicts the transfer of goods or services to the customer. Capacity, which is a stand-ready obligation to deliver energy when required by the customer, is measured based on the availability of the generation plants.

k) Finance income and finance costs

Finance income comprises interest income on funds invested, and fair value gains on financial assets at fair value through profit or loss. Interest income is recognized in profit or loss at amortized cost using the effective interest method. Finance cost comprise interest expense on borrowings, impairment losses recognized on financial assets (other than trade receivables) and reclassifications of amounts previously recognized in other comprehensive income.

Borrowing costs that are not directly attributable to the acquisition, construction or production of a qualifying asset are recognized in profit or loss using the effective interest method.

Foreign currency gains and losses are reported on a net basis as either finance income or finance cost depending on whether foreign currency movements are in a net gain or net loss position.

l) Income taxes

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Group operates and generates taxable income.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the statement of profit or loss. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax is provided using the liability method on temporary differences between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date.

Deferred tax liabilities are recognized for all taxable temporary differences, except:

- When the deferred tax liability arises from the initial recognition of goodwill or an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss;
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, when the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future

Deferred tax assets are recognized for all deductible temporary differences, the carry forward of unused tax credits and any unused tax losses. Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry forward of unused tax credits and unused tax losses can be utilized, except:

- When the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss;
- In respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized outside profit or loss is recognized outside profit or loss. Deferred tax items are recognized in correlation to the underlying transaction either in OCI or directly in equity.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognized subsequently if new information about facts and circumstances change. The adjustment is either treated as a reduction in goodwill (as long as it does not exceed goodwill) if it was incurred during the measurement period or recognized in profit or loss.

Uncertain tax positions

In determining the amount of current and deferred taxes ILAP Group takes into account the impact of uncertain tax positions and whether additional taxes and interest may be due. ILAP Group believes that its accruals for tax liabilities are adequate for all open tax years based on its assessments of various factors, including interpretations of tax laws and prior experience. This assessment relies on estimates and assumptions and may involve a series of judgments about future events. New information may become available that causes the Group to change its judgment regarding the adequacy of existing tax liabilities; such changes to tax liabilities will impact tax expense in the period when such a determination is made.

m) Current versus non-current classification

The Group presents assets and liabilities in statement of financial position based on current/non-current classification. An asset is presented as current when it is:

- Expected to be realized or intended to sold or consumed in normal operating cycle
- Held primarily for the purpose of trading
- Expected to be realized within twelve months after the reporting period, or
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least twelve months after the reporting period.

All other assets are classified as non-current.

A liability is current when:

- It is expected to be settled in normal operating cycle

- It is held primarily for the purpose of trading
- It is due to be settled within twelve months after the reporting period, or
- There is no unconditional right to defer the settlement of the liability for at least twelve months after the reporting period.

The Group classifies all other liabilities as non-current.

Deferred tax assets and liabilities are classified as non-current assets and liabilities.

n) Fair value measurement

The Group measures financial instruments such as derivatives, at fair value at each balance sheet date. Fair-value related disclosures for financial instruments and non-financial assets that are measured at fair value or where fair values are disclosed are summarized in the following notes:

• Disclosures for valuation methods, significant estimates and assumptions (Note 8.c)
• Quantitative disclosures of fair value measurement hierarchy

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability

The principal or the most advantageous market must be accessible by the Group.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.
The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level input that is significant to the fair value measurement as a whole:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

For assets and liabilities that are recognized in the financial statements at fair value on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

For the purpose of fair value disclosures, the Group has determined classes of assets and liabilities on the basis of the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy, as explained above.

o) Leases

Under IFRS 16 *Leases*, the Group assesses at contract inception whether a contract is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

In the periods covered by these financial statements the Group has no contracts in which it acts as a lessor.

Acting as a lessee, the Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. The Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

Right-of-use assets

The Group recognises right-of-use assets at the commencement date of the lease (i.e., the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Right-of-use assets are depreciated on a straight-line basis over the shorter of the lease term and the estimated useful lives of the assets,

If ownership of the leased asset transfers to the Group at the end of the lease term or the cost reflects the exercise of a purchase option, depreciation is calculated using the estimated useful life of the asset. The right-of-use assets are also subject to impairment. Refer to the accounting policies in section i) Impairment of non-financial assets above.

The right-of-use assets are presented in the statement of financial position within Property, plant and equipment (see Note 7).

Lease liabilities

At the commencement date of the lease, the Group recognizes lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in-substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating the lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognized as expenses in the period in which the event or condition that triggers the payment occurs.

In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

The Group's lease liabilities are presented separately in the statement of financial position as Lease liabilities (see Note 10).

3. Significant accounting judgments, estimates and assumptions

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses, and the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The most important estimates used are:

- Impairment of non-current assets, including goodwill: Management determines, at each accounting close, whether there are indicators of impairment, and if so, whether non-current assets are impaired. The goodwill impairment test is performed every year irrespectively if the impairment indicators are present. The impairment test requires an estimation of the value in use or fair value less costs of disposal of assets or cash generating units. Both methods require management to estimate the expected future cash flows from assets or CGUs and determine an appropriate discount rate to calculate the present value of these cash flows.

- Deferred tax assets: Deferred tax assets are recognized in respect of unused tax losses to the extent it is probable that taxable profit is available against which the Company can utilize the benefits therefrom. The Group develops projections of future taxable profits to assess such probability and also considers tax planning opportunities that the Company would take in order to create or increase taxable income in a particular period before the expiry of a tax loss or tax credit carryforward.

4. New and amended standards and interpretations

The standards and interpretations, and improvements and amendments to IFRS that have been issued, but have not yet come into effect as of the date of these financial statements, are detailed below. The Company has not applied these standards in advance:

	Standards and Interpretations	Date of Mandatory Application
IFRS 17	Insurance Contracts	January 1, 2023

IFRS 17 Insurance Contracts

In May 2017, the IASB issued IFRS 17 Insurance Contracts, a new insurance contract specific accounting standard that addresses recognition, measurement, presentation, and disclosure issues. After going into effect, it will supersede IFRS 4 Insurance Contracts issued in 2005. The new standard applies to all kinds of insurance contracts, regardless of the type of entity that issues them, as well as certain guarantees and financial instruments with specific discretionary participation features. Some exceptions within the scope might be applied.

IFRS 17 will be effective for periods beginning on or after January 1, 2023, and comparative figures are required. Early application is permitted as long as the entity also applies IFRS 9 Financial Instruments on or before IFRS 17 first application.

	Amendments	Date of Mandatory Application
IFRS 9, IAS 39, IFRS 7, IFRS 4 e IFRS 16	Interest Rate Benchmark Reform Phase 2	January 1, 2021
IFRS 3	Reference to the Conceptual Framework	January 1, 2022
IAS 16	Property, plant and equipment: proceeds before intended use	January 1, 2022
IAS 37	Onerous contracts – cost of fulfilling a contract	January 1, 2022
IAS 1	Classification of liabilities as current or non-current	January 1, 2023
IFRS 10 e IAS 28	Consolidated Financial Statements – sales or contributions of assets between and investor and its associates or joint ventures	To be determined

IFRS 9, IAS 39, IFRS 7, IFRS 4 e IFRS 16 Interest Rate benchmark Reform – Phase 2

In August 2020, the IASB issued the Interest Rate Benchmark Reform – Phase II that comprises amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16. Thus, the IASB finalizes its work to address the effects of the reform to interbank offered rates (IBORs) in financial reporting.

The amendments provide temporary exemptions that address the effects on financial reporting when interest rate benchmarks (IBORs) are replaced with alternative interest risk free rates.

Amendments are required and early application is permitted. A hedge relationship must be resumed if the hedge relationship was solely discontinued because of the changes implemented by the interest rate benchmark reform and thus, it would have not been discontinued if Phase II of the project had been applied then. While amendments must be applied retrospectively, an entity is not required to restate prior periods.

IFRS 3 Reference to the Conceptual Framework

In May 2020, the IASB issued amendments to IFRS 3 Business Combinations – Reference to the Conceptual Framework. These amendments will replace reference to a previous version of the IASB Conceptual Framework (1989 Framework) with a reference to the current version issued in March 2018, however, requirements have not substantially changed.

The amendments will be effective for periods beginning on or after January 1, 2022 and must be applied retrospectively. Early application is permitted if at the same time or earlier an entity also applies all the amendments contained in the amendments to the Reference to the Conceptual Framework of IFRS issued in March 2018.

The amendments will provide consistency in financial reporting and avoid potential confusion from having more than one version of the Conceptual Framework in use.

IAS 16 Property, plant and equipment: Proceeds Before Intended Use

This standard prohibits entities from deducting from the cost of an item of property, plant and equipment, any sale while bringing the asset to the location and conditions necessary for the asset to be capable of operating as intended by management. Instead, an entity will recognize the proceeds from a sale and cost of these elements in the income for the period, in accordance with the applicable Standards.

The amendment will be effective for periods beginning on or after January 1, 2022. The amendment shall be applied retrospectively only to the elements of property, plant and equipment available for use on or after the beginning of the first period presented in the financial statements of the entity applying the amendment for the first time.

IAS 37 Onerous contracts – Cost of fulfilling a contract

In May 2020, the IASB issued amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify the costs that an entity should include when assessing whether a contract is onerous or triggers losses.

The amendment is effective for periods beginning on or after January 1, 2022. The amendment shall be applied retrospectively to existing contracts at the beginning of the annual reporting period in which the entity applies the amendment for the first time (date of initial application). Early application is permitted and must be disclosed.

The amendments are intended to provide clarity and help to ensure a consistent application of the standard. Entities that have previously applied the incremental cost approach, will see an increase in provisions to reflect the inclusion of costs directly related to the contract activities, while entities that have previously recognized allowances for contractual losses based on the previous standard guidance, IAS 11 Construction Contracts, shall exclude the indirect cost allocation from their provisions.

IAS 1 Presentation of Financial Statements – Classification of liabilities as current or non-current

In June 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classification of liabilities as current or non-current.

The amendments are effective for periods beginning on or after January 1, 2022. Entities must carefully evaluate whether any aspect of the amendments might suggest that the terms of their existing loan agreements should be renegotiated. In this context, it is worth noting that amendments shall be applied retrospectively.

IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures– sale or contribution of assets between an investor and its associate or joint venture

The amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures (2011) address an inconsistency recognized between the requirements of IFRS 10 and those of IAS 28 (2011) in the treatment of the sale or contribution of assets between an investor and its associate or joint venture. Amendments issued in September 2014 establish that when the transaction involves a business (found in a subsidiary or not), a complete profit or loss is recognized. A partial profit or loss is recognized when the transaction involves assets that do not constitute a business, even when the assets are found in a subsidiary. The date of mandatory application of these amendments is yet to be determined, because the IASB is waiting for the results of its investigation project on the accounting using the equity method. The amendments must be applied retrospectively and early adoption is permitted, which must be disclosed.

5. Regulation and Operation of the Power System

The electric sector in Chile is regulated by the General Electricity Services Act contained in DFL No. 1 of 1982 of the Ministry of Mining, whose consolidated and coordinated text was set by DFL No. 4 of 2006 of the Ministry of Economy ("Electricity Act") and its corresponding Regulations, contained in DS No. 327 of 1998. Three government entities have the responsibility for the implementation and enforcement of the Electricity Act: the National Energy Commission (“CNE”, for its acronym in Spanish for *Comisión Nacional de Energía*), which has the authority to propose regulated tariffs (node prices) and to develop indicative plans for the construction of new generating units; the Superintendence of Electricity and Fuels (“SEC”, for its acronym in Spanish for *Superintendencia de Electricidad y Combustibles*), which supervises and monitors compliance with laws, regulations and technical standards for the generation, transmission and distribution of electricity, liquid fuels and gas; and finally, the Ministry of Energy, created in 2009, which is responsible for proposing and conducting public policies on energy matters and brings under his authority the SEC, the CNE and the Chilean Nuclear Energy Commission (CChEN, for its acronym in Spanish for *Comisión Chilena de Energía Nuclear*) strengthening coordination and facilitating a comprehensive view of the sector. The Act also features an Agency for Energy Efficiency and the Renewable Energy Center. The act also establishes an Expert Panel whose main function is to solve discrepancies that occur between actors in the electric market: electricity companies, system operator, regulator, etc.

From a physical standpoint, the Chilean electric sector is divided into three electric systems: the SEN (“SEN” for its acronym in Spanish for *Sistema Eléctrico Nacional*), and two isolated small systems: Aysén and Magallanes. The SEN, main electrical system, extends longitudinally for 3,100 km. It is composed of the former Central Interconnected system (SIC for its acronym in Spanish for *Sistema Interconectado Central*) and Norte Grande Interconnected system (SING for its acronym in Spanish for *Sistema Interconectado del Norte Grande*). As of March 2021 it has a net installed capacity of 25,373 MW.

The organization of Chilean electric industry mainly distinguishes three activities, which are: generation, transmission and distribution, which operate in an interconnected and coordinated manner, and whose main objective is to provide electrical energy to the market at minimum cost and preserving standards of quality and safety of service required by electrical regulations. Due to its characteristics, transmission and distribution activities are natural monopolies, reason why these are segments regulated as such by electrical regulation, requiring open access to networks and definition of regulated tariffs.

ccording to the Electricity Act, companies involved in generation and transmission in an interconnected power system must centrally coordinate their operations through an operating entity, the National Electric Coordinator (CEN for its acronym in Spanish for *Coordinador Eléctrico Nacional*) in order to operate the system at minimum cost while preserving service security. For this, the CEN plans and performs the operation of the system, including the calculation of hourly marginal cost, price at which energy transfers made between generators in the CEN are valued (spot market).

Therefore, the decision of generation of each company is subject to CEN's operating plan. Each company, in turn, can freely decide whether to sell its energy to regulated or unregulated customers. Any surplus or deficit between their sales to customers and their production is sold to or bought from other generators at spot market price.

A generating company may have the following types of customers:

a) Regulated customers

Correspond to those small and medium industries, residential and commercial consumers whose connected capacity is less than or equal to 500 kW, and which are located in the concession area of a distribution company. In this case the distribution company acts as buyer to the generating company. Customers with consumptions between 500 kW and 2,000 kW may opt between the regulated or unregulated pricing mechanism. Until 2009, the price of energy transfer between generators and distribution companies to supply regulated customers had a maximum value called the node price, which is regulated by the Ministry of Energy. Node prices are determined every six months (April and October), according to a report issued by the CNE, based on projections of marginal costs of the system expected for the following 48 months. From 2010, and as the validity term of agreements at node price is expiring, this transfer price between generation and distribution companies is replaced by the result of tenders conducted in a regulated process, with a maximum price set by the authority every six months.

b) Unregulated customers

Corresponds to that portion of the demand that has a connected capacity of more than 2,000 kW, mainly industrial and mining clients. These consumers may freely negotiate their prices of power supply with generators and/or distributors. Customers with capacity between 500 and 2,000 kW, as noted in the previous section, have the option to contract energy at prices that can be agreed with their suppliers or remain subject to regulated prices, for a minimum period of four years in each regime.

c) Short-term or spot market

Corresponds to energy and power transactions between generating companies, resulting from the coordination made by the CEN in order to achieve the economic operation of the system, and the excess (deficit) of its production regarding its commercial commitments is transferred through sales (purchases) to other generators coordinated by the CEN. In the case of energy, transfers are valued at marginal cost and in the case of power (*capacity or "potencia"*), at the corresponding node price, according to the price set semiannually by the authority. The capacity payable to each generator depends on a calculation made centrally by the CEN annually, thus obtaining the firm capacity of each plant, a value that is independent of its dispatch.

Since 2010, with the enactment of Law 20,018, which changed the regulatory framework for the electricity sector, distribution companies must ensure an uninterrupted supply for its total demand projected to three years, for which long-term public tender processes shall be conducted.
In renewable energy matters, Law 20,257 was enacted in April 2008, introducing amendments to the Electricity Law with respect to the generation of electricity from Non-Conventional Renewable Energy sources (ERNC, for its acronym in Spanish). The main aspect of this Act is that it forces generators to ensure that -at least- 5% of its energy sold to customers comes from these renewable sources, between 2010 and 2014, progressively increasing in 0.5% from year 2015 until 2024, when a 10% will be achieved. The CEN, with information on actual operation and contracts reported by generating companies, conducts annual balances to verify compliance with this Act.

In October 2013, Development Incentive Act of ERNC was amended, increasing the level of requirement to generators with contracts executed after July 1st, 2013, so that the percentage to be supplied with this kind of technologies progressively reaches a 20% by 2025. This requirement is not imposed on agreements executed prior to that date, to which shall apply the mandates established in Law 20,257 of 2008. Additionally, if the regulator foresees that the encouraged development due to market signals is an insufficient incentive to comply with percentages intended by this act, an obligation for the Ministry of Energy was introduced, to conduct Public Tenders in order to award 12-year power purchase agreements to ERNC projects.

6. Cash and cash equivalents

As of March 31, 2021, and December 31, 2020, the composition of cash and cash equivalents is as follows:

ThUS$	March 31, 2021	December 31, 2020
Bank balances	2,639	7,363
Total	**2,639**	**7,363**

Bank balances consists of current accounts. There are no restrictions to these balances.

The breakdown by currency of cash and cash equivalents is detailed as follows:

ThUS$	USD	CLP	Total
March 31, 2021	19	2,620	**2,639**
December 31, 2020	3,383	3,980	**7,363**

7. Property, plant and equipment

a) Movements

The movements during the three-month period ended March 31, 2021 and during the year 2020 are as follows:

2021	ThUS$			
	Beginning balance	Additions	Adjustments /Transfers	Ending balance
Cost				
Land	10,705	-	-	**10,705**
Right-of-use assets (*)	12,684	-	-	**12,684**
Infrastructure	42,744	-	-	**42,744**
Machinery and equipment	364,798	-	-	**364,798**
Civil works	45,860	-	14	**45,874**
Other equipment	2,013	18	3	**2,034**
Furniture and fittings	168	11	-	**179**
Decommissioning costs	48,994	-	-	**48,994**
Work in progress	701	10	(17)	**694**
Total Cost	**528,667**	**39**	**-**	**528,706**
Accumulated Depreciation				
Infrastructure	(12,118)	(457)	-	**(12,575)**
Right-of-use assets (*)	(1,176)	(147)	-	**(1,323)**
Machinery and equipment	(104,405)	(3,691)	-	**(108,096)**
Civil works	(8,647)	(503)	-	**(9,150)**
Other equipment	(884)	(28)	-	**(912)**
Furniture and fittings	(160)	(1)	-	**(161)**

Decommissioning costs	(6,013)	(501)	-	**(6,514)**
Total Accumulated Depreciation	**(133,403)**	**(5,328)**	**-**	**(138,731)**
Net Carrying Amount	**395,264**	**(5,289)**	**-**	**389,975**

(*) Includes right-of-use of a land recognized under IFRS 16.

2020	ThUS$			
	Beginning balance	Additions	Adjustments /Transfers	Ending balance
Cost				
Land	10,705	-	-	**10,705**
Right-of-use assets (*)	12,684	-	-	**12,684**
Infrastructure	42,744	-	-	**42,744**
Machinery and equipment	364,773	25	-	**364,798**
Civil works	45,860	-	-	**45,860**
Other equipment	1,998	15	-	**2,013**
Furniture and fittings	168	-	-	**168**
Decommissioning costs	48,994	-	-	**48,994**
Work in progress	859	34	(192)	**701**
Total Cost	**528,785**	**74**	**(192)**	**528,667**
Accumulated Depreciation				
Infrastructure	(10,289)	(1,829)	-	**(12,118)**
Right-of-use assets (*)	(588)	(588)	-	**(1,176)**
Machinery and equipment	(89,615)	(14,790)	-	**(104,405)**
Civil works	(6,635)	(2,012)	-	**(8,647)**
Other equipment	(737)	(147)	-	**(884)**
Furniture and fittings	(155)	(5)	-	**(160)**
Decommissioning costs	(4,009)	(2,004)	-	**(6,013)**
Total Accumulated Depreciation	**(112,028)**	**(21,375)**	**-**	**(133,403)**
Net Carrying Amount	**416,757**	**(21,301)**	**(192)**	**395,264**

(*) Includes right-of-use of a land recognized under IFRS 16.

b) Other Matters

In management's opinion, insurance policies taken are in accordance with the standards used by other companies in the industry and adequately cover potential losses for catastrophic events that may affect the assets owned by the Group.

As of March 31, 2021, and December 31, 2020, Parque Eólico Totoral owned by Norvind S.A. and Parque Eólico San Juan owned by San Juan S.A. assets are pledged to secure The Notes issued by ILAP (see Note 14).

Borrowing costs: During 2021 and 2020 the Group did not capitalize any borrowing costs. Borrowing costs incurred and capitalized in prior years are included in the initial cost of machinery and equipment. Each entity in charge of constructing the power plant took its own debt, so all the borrowing costs were specific and, as a consequence, 100% of such borrowing costs were capitalized during respective construction periods.

8. Intangible assets other than goodwill

The composition and movements in intangible assets other than goodwill during the three-month period ended March 31, 2021 and during the year 2020 are as follows:

March 31, 2021	Th$USD			
	Beginning balance	Additions	Adjustments/ Transfers	Ending balance
Cost				
Project development costs	82	-	-	82
Easements	449	-	-	449
Total Cost	**531**	**-**	**-**	**531**
Accumulated Amortization				
Project development costs	(40)	(2)	-	(42)
Total Accumulated Amortization	**(40)**	**(2)**	**-**	**(42)**
Net Carrying Amount	**491**	**(2)**	**-**	**489**

2020	Th$USD			
	Beginning balance	Additions	Adjustments/ Transfers	Ending balance
Cost				
Project development costs	82	-	-	82
Easements	449	-	-	449
Total Cost	**531**	**-**	**-**	**531**
Accumulated Amortization				
Project development costs	(32)	(8)	-	(40)
Total Accumulated Amortization	**(32)**	**(8)**	**-**	**(40)**
Net Carrying Amount	**499**	**(8)**	**-**	**491**

9. Inventory

The composition of inventory as at March 31, 2021 and December 31, 2020 is as follows:

Inventory	2021	2020
Spare Parts	93	63
Total	**93**	**63**

10. Leases liabilities

The Group has a lease contracts for the use of a land on which San Juan's wind farm is located for a period of twenty one years.

The carrying amounts of right-of-use assets recognized and the movements during the year 2021 are presented in the Note 7.

Set out below are the carrying amounts of lease liabilities from leases classified before adoption of IFRS 16 as operating leases and the movements during the period:

Lease Liabilities	March 31, 2021	December 31, 2020
Beginning balance	12,014	12,357
Accretion of interest	161	662
Amortization	(251)	(1,005)
Ending balance	**11,924**	**12,014**
Current	362	362
Non-current	11,562	11,652

The following are the amounts recognized in profit or loss in relation to those lease contracts:

Lease	March 31, 2021	March 31, 2020
Depreciation expense of right-of-use assets	(147)	(149)
Interest expense on lease liabilities	(161)	(220)
Variable lease payments	(219)	(85)
Total amount recognized in profit or loss	**(527)**	**(454)**

The San Juan lease contract contains variable payments based on the plant's generation. Management's objective is to align the lease expense with actual production and revenue earned.

Reconciliation of changes in lease liabilities to the cash flow statement are as follows:

Type of Liability	January 1, 2021	Cash Flows		Accrued interest	March 31, 2021
		Repayment	Interest paid		
Lease liabilities	12,014	(90)	(161)	161	11,924

Type of Liability	January 1, 2020	Cash Flows		Accrued interest	December 31, 2020
		Repayment	Interest paid		
Lease liabilities	12,357	(343)	(662)	662	12,014

11. Financial instruments and risk management

ILAP Group has exposure to the following risks arising from financial instruments:

- Credit risk
- Liquidity risk
- Market risk

The activities of ILAP Group expose it to a series of financial risks: market risks (including currency risk and interest rate risk), credit risk and liquidity risk. The Group's overall risk management program focuses mainly on the unpredictability of financial markets and seeks to minimize the potential adverse effects on its financial performance.

a) **Risk management framework**

Senior Management is responsible for establishing the risk management policies of the Group, which aim to identify, analyse and mitigate the main risks faced by the business.

The Group's risk management policies are established to identify and analyse the risks faced by the Group, to set appropriate risk limits and controls, and to monitor risks and adherence to limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Group's activities. ILAP Group, through its standards and procedures, aims to develop a disciplined and constructive control environment in which all employees understand their roles and responsibilities.

b) **Credit risk**

Credit risk is the risk of financial loss to the ILAP Group if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally on accounts receivable, investments in mutual funds and bank balances, including time deposits of the Group.

The ILAP Group's policies for managing credit risk of its customers include the assessment of financial information and the measurement of parameters such as liquidity and solvency. Trade receivables consist of balances due from creditworthy customers, including mainly large industrial clients, electricity distribution companies and other generation companies.

The ILAP Group invests in highly liquid instruments (time deposits at bank and money market mutual funds) held at premium financial institutions.

The carrying amounts of financial assets recorded in the financial statements represent the maximum exposure to credit risk of those instruments, as follows:

Types of assets	ThUS$	
	March 31, 2021	December 31, 2020
Cash and cash equivalents	2,639	7,363
Trade and other current receivables	7,188	10,565
Current receivables from related parties	3,728	3,836
Total Current Assets	**13,555**	**21,764**
Trade and other current receivables, non-current	12,063	11,742
Total Non-Currents Assets	**12,063**	**11,742**
Total	**25,618**	**33,506**

ILAP Group held cash and cash equivalents of ThUS$ 2,639 as of March 31, 2021, which represents its maximum credit exposure on these assets. Cash and cash equivalents are held with banks and financial institutions with a proven reputation.

Due to the nature of the business, trade and other receivables represent a very low risk for the Group as all participants in the electricity markets in Chile are by law obliged to pay their obligations in the following month after the energy is consumed. The counterparties to the Company's PPAs as well as other relevant electricity market participants generally possess high credit ratings.

Impairment

The Group has not recognized relevant impairment (ECL) on trade receivables, since there is no evidence of significant impairment of those assets.

The age of trade receivables and other receivables that were not impaired is as follows:

	ThUS$				
2021	Current	Due 31-90 days	Due 91-120 days	Non-current (*)	Total March 31, 2021
Trade and other receivables	6,370	818	-	12,063	19,251

	ThUS$				
2020	Current	Due 31-90 days	Due 91-120 days	Non-current (*)	Total December 31, 2020
Trade and other receivables	7,692	1,874	999	11,742	**22,307**

(*) Refer to Note 12. for further details on this balance.

c) **Liquidity risk**

Liquidity risk is the risk that the Group will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset.

Management supervises cash flow projections based on the Group's liquidity requirements to ensure there is enough cash, and also that unused credit lines are available, to cover its operational needs, without incurring unacceptable losses or risking damage to the Group's reputation. Such projections take into consideration debt amortization schedules and the compliance with the debt covenants.

As of March 31, 2021, and December 31, 2020, current financial liabilities held by ILAP Group have short-term maturities. The balances of current financial liabilities are detailed as follows:

In thousands of United States dollars (ThUS$)	March 31, 2021	December 31, 2020
Trade and other payables	13,877	10,288
Other current financial liabilities	12,175	16,404
Total	**26,052**	**26,692**

The balance of Other current financial liabilities consists mainly of current portion of loans payable. Refer to the Note 14 for further details.

The following are the remaining contractual maturities of loans and borrowings at the end of the reporting period, including estimated interest and excluding the impact of the arrangements for compensation payments:

	Contractual Cash Flows			
Non derivative financial liabilities	1-3 month ThUS$	3-12 month ThUS$	+1 years ThUS$	Total March 31, 2021
Interest	161	10,889	155,446	166,496
Capital of financial liabilities	90	7,461	393,608	401,159
Total	**251**	**18,350**	**549,054**	**567,655**

	Contractual Cash Flows			
Non derivative financial liabilities	1-3 month ThUS$	3-12 month ThUS$	+1 years ThUS$	Total December 31, 2020
Interest	10,726	10,894	155,602	177,222
Capital of financial liabilities	5,816	7,457	393,703	406,976
Total	**16,542**	**18,351**	**549,305**	**584,198**

d) Market risk

Senior Management is responsible for establishing the risk management policies of the Group, which aim to identify, analyse and mitigate the main risks faced by the business.

Below there is overview of the business´ main market risks and description of how they are managed.

e) Currency risk

The Company is exposed to currency risk as some of its transactions and the related balances of monetary assets and liabilities are denominated in a currency different from the U.S. dollar, which is the Company's functional currency. Those transactions are mainly denominated in Chilean pesos.

Management considers that currency risk is not significant due to the short collection and payment periods of the transactions involved.

During three-month periods ended March 31, 2021 and 2020, the Company recorded a net losses due to exchange differences of ThUS$ 415 and ThUS$ 789, respectively. These results are presented under the heading "Exchange Differences" in the statement of comprehensive income.

The Group intends to naturally offset the currency risk exposure trying to maintain similar levels of assets and liabilities in the same currencies and similar maturity profiles. The Group does not currently use derivative instruments to hedge currency risk.

f) Interest rate risk

ILAP is not exposed to interest rate risk because its debt is at a fixed rate of 5.35% and deposits in banks have a very short maturity period.

g) Power prices

During 2021, the Company's commercial strategy was to minimize the risk of exposure to the spot market, given the changing market conditions, especially the consumption of the Distribution companies, with which the Group has long-term agreements. In summary, the above is reflected in obtaining new supply agreements for surplus energy of San Juan and Norvind. In particular, approximately 104 GWh-year were awarded during 2020 between Norvind and San Juan. These new agreements, together with the old ones, lead to a portion of less than 5% of the production to be sold to the spot market, thus minimizing the Company's risk and ensuring income for the next 4 years, focusing administrative efforts on optimizing the operation.

h) **Capital management**

The LAP Group's Board of Directors' policy is to maintain a sound capital base to preserve confidence from investors, creditors and the market, as well as supporting the business´ future development. The Company´s capital base is composed by equity contributions by shareholders and external debt financing obtained from multiple respected international and local financial institutions.

In terms of managing its capital structure, ILAP also works towards maximizing returns for its shareholders, by trying to continuously improve the terms of its funding (e.g. improving cost and tenor of its existing financings). As an example, the Group refinanced the debt of Norvind and San Juan projects in 2017.

In line with the industry practice, the ILAP Group uses ratio analyses to monitors its capital strength. One of this metrics is the leverage ratio, which is calculated by dividing net debt by total equity. Net debt corresponds to total indebtedness (including current and non-current debt) less cash and cash equivalents.

The ILAP Group does not have an established policy of maximum leverage. In practice, the maximum debt to total assets provided by external lenders for power generation assets is approximately 80%.

The debt-equity ratio of the Group at the end of the period is as follows:

ThUS$		
Debt-Equity	March 31, 2021	December 31, 2020
Total liabilities	468,592	475,304
Less: cash and cash equivalents	(2,639)	(7,363)
Less: time deposits	-	-
Net debt	**465,953**	**467,941**
Total Equity	(14,626)	(9,882)
Debt-equity ratio	**(31.86)**	**(47.35)**

i) **Classification of financial instruments by nature and type**

<u>Assets</u>

As of March 31, 2021, and December 31, 2020, the detail of financial assets (other than cash), classified by nature and type, is as follows:

March 31, 2021 Types of Assets ThUS$	Debt instruments at amortized cost	Derivatives	Total
Trade and other current receivables	7,188	-	7,188
Related parties current receivables	3,728	-	3,728
Total current	**10,916**	**-**	**10,916**
Trade and other current receivables, non-current	12,063	-	12,063
Total non-current	**12,063**	**-**	**12,063**
Total	**22,979**	**-**	**22,979**

December 31, 2020 Types of Assets ThUS$	Debt instruments at amortized cost	Derivatives	Total
Trade and other current receivables	10,565	-	10,565
Related parties current receivables	3,836	-	3,836
Total current	**14,401**	**-**	**14,401**
Trade and other current receivables, non-current	11,742	-	11,742
Total non-current	**11,742**	**-**	**11,742**
Total	**26,143**	**-**	**26,143**

Liabilities

As of March 31, 2021, and December 31, 2020, the detail of financial liabilities, classified by nature and type is as follows:

Types of Liabilities ThUS$ March 31, 2021	Loans and payables	Derivatives	Total
Other current financial liabilities	12,175	-	12,175
Trade and other payables	13,877	-	13,877
Current account payables related parties	4,889	-	4,889
Lease liabilities	362	-	362
Total current	**31,303**	**-**	**31,303**
Other non-current financial liabilities	372,501	-	372,501
Lease liabilities	11,562	-	11,562
Total non-current	**384,063**	**-**	**384,063**
Total	**415,366**	**-**	**415,366**

Types of Liabilities ThUS$ December 31, 2020	Loans and payables	Derivatives	Total
Other current financial liabilities	16,404	-	16,404
Trade and other payables	10,288	-	10,288
Current account payables related parties	4,902	-	4,902
Lease liabilities	362	-	362
Total current	**31,956**	**-**	**31,956**
Other non-current financial liabilities	378,811	-	378,811
Lease liabilities	11,652	-	11,652
Total non-current	**390,463**	**-**	**390,463**
Total	**422,419**	**-**	**422,419**

j) **Fair value**

Fair value hierarchy:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

The book values and fair values of financial assets and liabilities at the end of each year is as follows:

March 31, 2021	Carrying amount ThUS$	Fair value ThUS$	Fair value		
			Level 1 ThUS$	Level 2 ThUS$	Level 3 ThUS$
Other current and non-current financial Liabilities	384,676	424,124	-	-	424,124
Total	**384,676**	**424,124**	**-**	**-**	**424,124**

December 31, 2020		Fair value ThUS$	Fair value		
			Level 1	Level 2	Level 3

	Carrying amount ThUS$		ThUS$	ThUS$	ThUS$
Other current and non-current financial Liabilities	395,215	440,286	-	-	440,286
Total	**395,215**	**440,286**	**-**	**-**	**440,286**

The recoverable amounts of PP&E and intangible assets determined in the impairment test have been calculated through the discount cash-flow models. This fair value calculation is classified as level 3 (see Note 8.c) for further details).

The Group has estimated that the carrying amounts of accounts payable and receivable of short-term nature are a reasonable approximation of their fair values.

12. Trade and other receivables

As of 31 March 2021, and 31 December 2020, the trade receivables and other receivables are composed as follows:

ThUS$	March 31, 2021		December 31, 2020	
	Current	Non-current	Current	Non-current
Trade receivables	6,876	12,063	9,219	11,742
VAT	36	-	152	-
Other receivables	276	-	1,194	-
Total	**7,188**	**12,063**	**10,565**	**11,742**

The Company recognized a balance of non-current trade receivables amounting to ThUS$ 12,063 as of March 31, 2021 and ThUS$ 11,742 as of December 31, 2020, following certain regulatory changes in Chile.

San Juan and Norvind are affected by the Law 21.185 issued on 2 November 2019 that created a transitional mechanism for stabilization of electricity prices for customers subject to regulation of rates. This law effectively "freezes" electricity prices that distribution companies ("DISCOs") bill to such customers starting from July 2019, with the referential (lower) prices at the level of rates as of June 2019. Those prices are referred to as stabilized consumer prices ("PEC" form its acronym in Spanish).

From 2021, the PEC will be adjusted by Chilean IPC ("adjusted PEC"). This adjustment will be applied until December 31, 2027, the maximum date at which the differences between the prices established in the original energy sale contracts between the generation companies (like San Juan and Norvind) and DISCOs and the PEC and adjusted PEC rates will be passed to the final customers.

During the stabilization period, that is, from July 1, 2019 to December 31, 2027, the CNE (National Commission of Energy), a Chilean regulator, will continue issuing decrees every 6 months that will include the PEC / adjusted PEC applicable to the next billing period, as well as the price that reflects the original conditions (price) of the contracts (sometimes referred to as the "node prices"), expressing the differences not collected by each contract, in the equivalent US$.

As a general rule, the differences to be collected that are generated from the application of the law will be interest-free. Exceptionally, the amounts not collected as of January 1, 2026 shall bear interest equal to six-month Libor, or the equivalent rate that replaces it, plus a spread corresponding to country risk at the date of application.

If the average node prices result in prices higher than the PEC or adjusted PEC, as appropriate, the prices will be adjusted downwards. Otherwise, prices will be increased, in order to recover previously unbilled amounts.

From July 2023 or until an amount of up to 1,350 million US dollars is accumulated in the entire PEC mechanism, the uncollected amounts cannot be increased, therefore, the CNE must adjust the PEC.

If during the period between 2025 and 2027, the CNE projects that the uncollected amounts cannot be fully recovered, it will determine the necessary adjustments to the PEC to fully extinguish the amounts before December 31, 2027.

The application of the law caused a greater lag between billing and collection of revenues for the whole generation industry in Chile with the corresponding financial and accounting impact that the situation entails.

ILAP estimated and recognized, as of March 31, 2021, the unbilled revenue for the PEC concept amounting to ThUS$ 12,063 (ThUS$ 11,742 as at December 31, 2020), determining that the financing component is immaterial. As per the PEC mechanism described above, the balance is expected to be collected in the period that exceed one year and in consequence is classified as non-current asset.

13. Trade and Other Payables

The breakdown of the balance is as follows:

ThUS$	March 31, 2021	December 31, 2020
Invoices payable	13,252	10,054
VAT	625	234
Total	**13,877**	**10,288**

14. Other Financial Liabilities

The detail as of March 31, 2021 of this balance is as follows:

Issuer	Creditor	Nominal interest rate	Total	Current	Non-current
ILAP	The Bank of New York Mellon	5.35%	389,235	13,937	375,298
	Deferred Financing Expenses		(4,559)	(1,762)	(2,797)
			384,676	**12,175**	**372,501**

The summarized maturity dates of this instrument (based on its carrying amount) are as follows:

Period	March 31, 2021 ThUS$
Within 1 year	12,175
Between 1 and 5 years	76,724
More than 5 years	295,777
Total	**384,676**

The detail as of December 31, 2020 of this balance is as follows:

Company	Creditor	Nominal interest rate	Total	Current	Non-current
ILAP	The Bank of New York Mellon	5.35%	400,243	18,192	382,051
	Deferred Financing Expenses		(5,028)	(1,788)	(3,240)
			395,215	**16,404**	**378,811**

The summarized maturity dates of this instrument (based on its carrying amount) are as follows:

Period	December 31, 2020 ThUS$
Within 1 year	16,404
Between 1 and 5 years	74,654
More than 5 years	304,157
Total	**395,215**

Reconciliation of changes in financial liabilities to the cash flow statement:

Type of Liability	January 1, 2021	Cash Flows		Accrued interest	Amortization of deferred financing expenses	March 31, 2021
		Repayment	Interest paid			
Bonds	400,243	(5,725)	(10,566)	5,283	-	389,235
Deferred Financing Expenses	(5,028)	-	-	469	-	(4,559)
	395,215	**(5,725)**	**(10,566)**	**5,752**	**-**	**384,676**

Type of Liability	January 1, 2020	Cash Flows		Accrued interest	Amortization of deferred financing expenses	December 31, 2020
		Repayment	Interest paid			
Bonds	410,750	(10,367)	(21,572)	21,432	-	400,243
Deferred Financing Expenses	(6,834)	-	-	-	1,806	(5,028)
	403,916	**(10,367)**	**(21,572)**	**21,432**	**1,806**	**395,215**

Debt covenants are described below. The Company has complied with all the obligations under debt agreements as of March 31, 2021.

In September 2017, ILAP entered into a Note Purchase Agreement (NPA) with private investors for ThUS$ 412,000. The main obligations / restrictions for ILAP under the contract are as follows:

a) Compliance with Laws.
b) Maintain properties and businesses insurance against casualties and contingencies.
c) Own directly, not less than 99.99% of the Ownership Interest of each Guarantor free and clear of any Lien (other than Permitted Liens).
d) Each Obligor will preserve and keep its corporate, limited liability company.
e) Each Obligor will maintain proper books of record and account in conformity with IFRS and all applicable requirements of any Governmental Authority.
f) Each Obligor shall (i) observe and perform all obligations, covenants and agreements to be performed by it under, and comply with all conditions under, each Material Contract.
g) Delivery of Additional Material Contracts no later than thirty (30) days after the execution of any Additional Material Contract or any Replacement Material Contract.
h) Comply with all applicable Environmental Laws, except where such failure could not, individually or in the aggregate reasonably be expected to have a Material Adverse Effect.
i) The Borrower shall not make or permit any Investments, Subsidiaries, Partnership or Management Agreements.
j) None of the Obligors will engage in any business other than owning, operating and maintaining its Project(s).
k) None of the Obligors will incur, assume or permit to exist (upon the happening of a contingency or otherwise) any Lien on any of its property or assets, including the Collateral, except Permitted Liens.

l) No Obligor will (i) Transfer any Ownership Interest (or portion thereof) of any of its Subsidiaries (if any) or (ii) Transfer any of its properties or assets, other than, in the case of this clause (ii), Permitted Dispositions and any transaction permitted.

m) No Obligor will, at any time, directly or indirectly, declare, make or agree to pay, or incur any liability to declare or make or agree to pay, any Restricted Payment (including any related Capital Decrease) except if the Debt Service Coverage Ratio for the Company and the Guarantors (consolidated in accordance with IFRS) for (A) the period of the four consecutive historical fiscal quarters most recently then ended exceed 1.30 to 1.00, and (B) the period of the four consecutive prospective fiscal quarters then commencing with the Payment Date immediately preceding the date of such proposed Restricted Payment, exceeded 1.25 to 1.00,

n) No Obligor will, without the prior written consent of the Required Holders, (i) cancel, terminate, accept a surrender of or only with respect to a Material Contract that is an O&M Agreement, permit to expire, any Material Contract, unless such Material Contract is replaced with a Replacement Material Contract or (ii) amend, modify, supplement or assign any Material Contract if any such amendment, modification, supplement or assignment could reasonably be expected to result in a Material Adverse Effect.

o) No Obligor will enter into any Additional Material Contract, without the prior written consent of the Required Holders.

p) No Obligor will take any action that would cause such Obligor to be considered an “investment company” or a company controlled by an “investment company”.

q) No Obligor will enter into any Swap Contract or engage in any similar transaction for speculative purposes.

The Company has complied with all the obligations as of March 31, 2021.

15. Related parties

a) Balances and transactions with related entities

Transactions with related parties are performed at market conditions.

At the reporting date, there are no warranties associated with related party balances or allowances for doubtful accounts.

Balances of accounts receivable are as follows:

Accounts receivable from related companies - ThUS$	Relationship	Current	
		March 31, 2021	December 31, 2020
Latin America Power S.A.	Immediate parent	2	2
Empresa Eléctrica Carén S.A.	Under common control	3,726	3,834
Total Receivable		**3,728**	**3,836**

Balances of accounts payable are as follows:

Accounts payable to related companies - ThUS$	Relationship	Current	
		March 31, 2021	December 31, 2020
Latin America Power S.A.	Immediate parent	1,735	1,748
LAP Holding B.V.	Ultimate parent	3,154	3,154
Total payable		**4,889**	**4,902**

b) Management and senior management

1. Management

Latin América Power S.A. is the Manager of the ILAP Group, who shall perform its duties through one of its representatives appointed by means of a private instrument or a public deed, with those powers expressly granted.

2. Remuneration and other compensations

The Manager does not receive any remuneration for its duties.

3. Expenses for Advisory to the Board of Directors

During the period ended March 31, 2021 and for the year ended December 31, 2020, the Manager did not incur in advisory expenses.

4. Remuneration of Senior Management members who are not Directors

There is no senior management personnel since those duties are carried out by employees of the LAP Group to which the Company belongs.

5. Guarantees given by the Company in favor of its Manager

During the period ended March 31, 2021 and for the year ended December 31, 2020, the Company has not conducted this type of operations.

6. Guarantee clauses: Manager and Management of the Company

The Company has not agreed any guarantee clauses with its Manager.

16. Provisions

Changes in the balance of the decommissioning provision during the period ended March 31, 2021 and for the year ended December 31, 2020, were as follows:

March 31, 2021 In thousands of US dollars (ThUS$)	Decommissioning costs provision
At January 1, 2021	**52,885**
Unwinding of discount	341
Other	-
At March 31, 2021	**53,226**

2020 In thousands of US dollars (ThUS$)	Decommissioning costs provision
At January 1, 2020	51,615
Unwinding of discount	1,330
Other	(60)
At December 31, 2020	**52,885**

17. Income taxes regime background

The current income tax is accounted for based on the taxable income determined for tax purposes. The recognition of deferred tax in respect of temporary differences and other events that generate differences between the taxable base of assets and liabilities and its accounting base is performed in conformity with IAS 12.

As of March 31, 2021, and December 31, 2020, the Company has not recorded any taxable profits for its operations, as it has accumulated tax losses.

The corporate income tax rate applicable to the Company and its subsidiaries in 2021 and 2020 is 27%.

18. Income tax assets and liabilities

a) Deferred taxes

The movement of deferred taxes is presented below:

March 31, 2021 ThUS$	Beginning balance	Recognized in profit or loss	Ending balance
Tax losses	32,776	1,727	34,503
Property, plant and equipment and intangibles	4,250	115	4,365
Other	(928)	(149)	(1,077)
Net deferred tax assets (liabilities)	**36,098**	**1,693**	**37,791**

December 31, 2020 ThUS$	Beginning balance	Recognized in profit or loss	Ending balance
Tax losses	33,356	(580)	32,776
Property, plant and equipment and intangibles	3,779	471	4,250
Other	(2,219)	1,291	(928)
Net deferred tax assets (liabilities)	**34,916**	**1,182**	**36,098**

Those balances are reflected in the statements of financial position as follows:

ThUS$	March 31, 2021	December 31, 2020
Assets	37,791	36,098
Liabilities	-	-
Net deferred tax assets (liabilities)	**37,791**	**36,098**

The recovery of those deferred tax asset balances depends on obtaining sufficient tax earnings in the future. The ILAP Group believes its future taxable profits projections provide convincing evidence to assert that those assets are recoverable. The Company also considers tax planning opportunities that the Company would take in order to create or increase taxable income in a particular period before the expiry of a tax loss or tax credit carryforward. It is worth mentioning that in the case of Chile tax losses do not expire according to the local law.

During the three-month period ended March 31, 2020, the Company decided to derecognize a portion of the deferred tax assets related to tax losses of ILAP that were not considered recoverable.

b) Amounts recognized in profit or loss:

	March 31,	
Current tax expense	2021	2020
Current tax year	-	-
Deferred tax benefit (expense)	-	-
Origination and reversal of temporary differences	1,693	(524)
Tax (expense) / benefit from continuing operations	**1,693**	**(524)**

c) Effective tax rate reconciliation

The table below shows a reconciliation of the effective tax rate for the three-month periods ended March 31, 2021 and 2020:

ThUS$	March 31, 2021		March 31, 2020	
	Amount	Rate	Amount	Rate
Loss before taxes	(6,437)		(3,346)	
Income tax benefit at statutory rate (27%)	1,738	27.0%	903	27.0%
Derecognition of deferred tax assets	-	-	(1,400)	(41.8%)
Non-taxable / non-deductible items and other differences	(45)	(0.7%)	(27)	(0.8%)
Income tax (expense) benefit at effective rate	**1,693**	26.3%	**(524)**	(15.6%)

19. Equity

Capital subscribed and paid

Inversiones Latin América Power Limitada is controlled by Latin América Power S.A. according to the following shareholding composition:

Company	Capital Paid USD $
LAP Chile S.A.	89,800,779
LAP Holding B.V.	8
Total	89,800,787

20. Revenue

The composition of revenue for the three-month periods ended March 31, 2021 and 2020 is as follows:

ThUS$	March 31	
	2021	2020
Energy sales	13,238	16,778
Capacity sales	2,320	4,138
Other revenue	59	4
Total	**15,617**	**20,920**

The following tables show revenues from customers with a participation higher than 10% in the total Group's sales for the for the three-month periods ended March 31, 2021 and 2020:

Revenue from external customers (ThUS$)	2021	%
Compañía General de Electricidad	3,330	21%
Total 2021	**3,330**	

Revenue from external customers (ThUS$)	2020	%
Enel Distribución Chile S.A.	4,762	23%
Total 2020	**4,762**	

21. Cost of Sales

The composition of cost of sales for the three-month periods ended March 31, 2021 and 2020 is as follows:

ThUS$	March 31,	
	2021	2020
Operating, management and servicing costs	6,272	7,739
Maintenance	1,294	1,152
Municipal tax	11	23
Corporate social responsibility expenses	16	1
Transmission costs	1,595	1,621
Insurance	264	178
Others	162	195
Depreciation and amortization for the period	5,304	5,728
Total	**14,918**	**16,637**

22. Administrative expenses

The composition of Administrative expenses for the three-month periods ended March 31, 2021 and 2020 is as follows:

ThUS$	March 31, 2021	March 31, 2020
Depreciation and amortization for the period	26	26
Services provided by third parties	390	385
Additional taxes	37	12
Travel expenses	5	7
Total	**458**	**430**

23. Finance expenses

The composition of finance expenses for the three-month periods ended March 31, 2021 and 2020 is as follows:

ThUS$	March 31, 2021	March 31, 2020
Interests on debts and borrowings	5,752	5,869
Other financial costs	9	3
Unwinding of discount on the decommissioning provision	341	333
Interests on lease liabilities	161	220
Total	**6,263**	**6,425**

24. Contingencies, Guarantees and Commitments

a) Contingencies

On April 30, 2015, the Chilean Internal Revenue Service ("SII") formally requested Norvind to provide the relevant supporting documentation regarding tax-losses declared in its annual income tax declaration (Form 22) corresponding to Tax Year 2012 (Commercial Year 2011). After reviewing the documentation presented by Norvind, the SII issued the Resolution number 195 ruling that the documentation submitted was not sufficient to support expenses and carryforward losses declared, for a total amount of ThUS$ 12,229. Thus, additional corporate income taxes and fines were determined for Tax Year 2012 for an amount of ThUS$ 2,631.

On September 21, 2015, Norvind submitted an administrative appeal ("RAV") before the SII adding new supporting documentation and accounting records. After the rejection of the RAV, and having exhausted all administrative remedies available, on December 17, 2015 Norvind requested the Judicial Review of the Resolution number 195 before the Tax Courts. In parallel, Norvind held conversations with the SII in order to explore resolution of the matter. Those negotiations resulted in a settlement executed on June 9, 2020, by which the SII recognized and set Norvind's tax-loss position (carryforward losses) for ThUS$ 4,243 per the Tax Year 2012; hence, Norvind shall pay no additional corporate tax nor fines regarding the Tax Year 2012.

On April 30, 2019, the SII issued the Resolution number 1109 whereby Norvind's tax losses declared in Tax Year 2016 (Commercial Year 2015) were reduced from ThUS$ 25,411 to ThUS$ 3,382. Such reduction consisted in the subtraction of the losses and expenses questioned in the Resolution number 195 (which at the time was being disputed before the Tax Courts, as described in the preceding paragraph), plus other expenses generated in subsequent years, under the argument that Norvind was not allowed to recognize expenses and carryforward losses determined under criteria already rejected through the Resolution 195.

On June 13, 2019, Norvind submitted a RAV requesting the validation of its tax-loss position. The RAV was denied. As a result, a Judicial Review was filed before the Tax Court and this procedure is still pending.

Based on the evaluation of criteria in IFRIC 23 *Uncertainty over Income Tax Treatment* the Group concluded that it is probable that its tax treatments related to the Norvind's expenses and tax losses challenged by the SII in the Resolution 1109 will be ultimately accepted by the taxation authorities.

b) Commitments

Commercially, ILAP has a policy of committing annual energy volumes through intermediate PPAs. As of 31 December 2020, the following energy sales commitments have been made:

Power Plant (subsidiary)	Volume sale commitment (MWh/year)
San Juan	439,813
Norvind	95,184
Total	**534,997**

25. COVID-19

The effects of the COVID-19 pandemic have affected all economies around the world, and Chile where the ILAP Group carries out its operating activities is no exception. Mobility restrictions and social distance measures such as curfews and quarantines have been imposed by authorities in both countries to contain the spread of the disease, thus affecting the normal course of business. Given the LAP's industry nature is essential utility, special permits were assigned by authorities to ensure the mobility of the LAP's power plants' workers under strict safety measures to avoid potential shutdowns or production curtailments allowing ILAP power plants to keep up and running during the whole year 2020. However, in Chile the Company's revenues were somehow affected by a lower demand of energy from regulated costumers which implies lower demand from electricity distribution companies (DiscCos) under the PPA contracts, forcing San Juan and Norvind to sell the energy surpluses to the spot market at lower prices.

In the short term, lower energy demand from Chilean DisCo continues to be a concern, however the successful COVID-19 vaccination process which is being executed by Chile, leading worldwide doses administered per 100 habitants, helps to mitigate the uncertainty around the recovery of the economic activity and therefore the energy demand.

26. Subsequent events

Between March 31, 2021 and the date of issuance of these consolidated financial statements, the Directors of the Company are not aware of any subsequent events that may significantly affect the interpretation of these consolidated financial statements.

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Consolidated Financial Statements as of December 31, 2020 and 2019, and for each of the three years in the period ended December 31, 2020, with the Independent Auditor's Report

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Independent Auditor's Report

To the Partners
Inversiones Latin America Power Ltda.

We have audited the accompanying consolidated financial statements of Inversiones Latin America Power Ltda. and subsidiaries, which comprise the consolidated statements of financial position as of 31 December 2020 and 2019, and the corresponding consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2020, and related notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in conformity with International Financial Reporting Standards; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Generally Accepted Auditing Standards in Chile. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material Misstatements.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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Building a better working world

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Inversiones Latin America Power Ltda. and subsidiaries as of 31 December 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020 in accordance with International Financial Reporting Standards.

EY Audit SpA

Santiago,
June 1, 2021

Consolidated Statements of Financial Position as of December 31, 2020 and 2019

Thousands of US Dollars (ThUS$)	Note	December 31, 2020	December 31, 2019
Assets			
Current assets			
Cash and cash equivalents	6	7,363	18,428
Trade and other current receivables	12	10,565	11,836
Accounts receivable from related entities	15	3,836	3,643
Inventory	9	63	-
Total current assets		**21,827**	**33,907**
Non-current assets			
Trade and other current receivables, non-current	12	11,742	1,245
Intangible assets other than goodwill	8.a	491	499
Property, plant and equipment	7.a	395,264	416,757
Deferred tax assets	17.a	36,098	36,149
Total non-current assets		**443,595**	**454,650**
Total assets		**465,422**	**488,557**
Equity and liabilities			
Current liabilities			
Other current financial liabilities	14	16,404	13,983
Trade and other payables	13	10,288	11,805
Accounts payable to related entities	15	4,902	4,724
Lease liabilities	10	362	343
Total current liabilities		**31,956**	**30,855**
Non-current liabilities			
Other non-current financial liabilities	14	378,811	389,933
Provisions	16	52,885	51,615
Lease liabilities	10	11,652	12,014
Deferred tax liabilities	17.a	-	1,233
Total non-current liabilities		**443,348**	**454,795**
Total liabilities		**475,304**	**485,650**
Equity			
Paid-in capital	19.a	89,801	93,001
Retained earnings (accumulated losses)		(90,094)	(70,964)
Result for the year		(9,589)	(19,130)
Equity attributable to the owners of the Parent		**(9,882)**	**2,907**
Non-controlling interests		-	-
Total equity		**(9,882)**	**2,907**
Total equity and liabilities		**465,422**	**488,557**

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Consolidated Statements of Comprehensive Income for each of the three years in the period ended December 31, 2020

Thousands of US Dollars (ThUS$)	Note	December 31,		
		2020	2019	2018
Profit or loss				
Revenue	20	72,887	62,516	52,097
Cost of sales	21	(55,477)	(50,540)	(44,644)
Gross profit		**17,410**	**11,976**	**7,453**
Administrative expenses	22	(2,836)	(2,287)	(2,416)
Operating profit		**14,574**	**9,689**	**5,037**
Finance income		16	216	219
Finance expenses	23	(25,279)	(25,730)	(25,504)
Foreign exchange differences		(82)	48	(171)
Impairment charges	24	-	(4,665)	-
Loss before taxes		**(10,771)**	**(20,442)**	**(20,419)**
Income tax benefit	18.b	1,182	1,312	5,515
Loss for the year		**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:				
Owners of the Parent		(9,589)	(19,130)	(14,904)
Non-controlling interests		-	-	-
Other comprehensive income (loss)		-	-	-
Total comprehensive loss for the year, net of tax		**(9,589)**	**(19,130)**	**(14,904)**
Attributable to:				
Owners of the Parent		(9,589)	(19,130)	(14,904)
Non-controlling interests		-	-	-

The accompanying notes 1 to 26 form an integral part of these unaudited interim consolidated financial statements

Consolidated Statements of Changes in Equity for each of the three years in the period ended December 31, 2020

Thousands of US dollars (ThUS$)	Paid-in capital	Retained earnings (accumulated losses)	Result for the year	Total equity
Opening balance 01-01-2020	**93,001**	**(70,964)**	**(19,130)**	**2,907**
Changes in equity				
Comprehensive Income				
Loss for the year	-	-	(9,589)	**(9,589)**
Appropriation of results	-	(19,130)	19,130	**-**
Capital reduction	(3,200)	-	-	**(3,200)**
Total changes in equity	**(3,200)**	**(19,130)**	**9,541**	**(12,789)**
Closing balance 31-12-2020	**89,801**	**(90,094)**	**(9,589)**	**(9,882)**

Thousands of US dollars (ThUS$)	Paid-in capital	Retained earnings (accumulated losses)	Result for the year	Total equity
Opening balance 01-01-2019	**93,001**	**(56,060)**	**(14,904)**	**22.037**
Changes in equity				
Comprehensive Income				
Loss for the year	-	-	(19,130)	**(19,130)**
Appropriation of results	-	(14,904)	14,904	**-**
Total changes in equity	**-**	**(14,904)**	**(4,226)**	**(19,130)**
Closing balance 31-12-2019	**93,001**	**(70,964)**	**(19,130)**	**2,907**

Thousands of US dollars (ThUS$)	Paid-in capital	Retained earnings (accumulated losses)	Result for the year	Total equity
Opening balance 01-01-2018	**117,604**	**(19,666)**	**(36,394)**	**61,544**
Changes in equity				
Comprehensive Income				
Loss for the year	-	-	(14,904)	**(14,904)**
Appropriation of results	-	(36,394)	36,394	**-**
Capital reduction	(24,603)	-	-	**(24,603)**
Total changes in equity	**(24,603)**	**(36,394)**	**21,490**	**(39,507)**
Closing balance 31-12-2018	**93,001**	**(56,060)**	**(14,904)**	**22,037**

Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2020

Thousands of US Dollars (ThUS$)	December 31,		
	2020	2019	2018
Cash flows from operating activities			
Loss before taxes	**(10,771)**	**(20,442)**	**(20,419)**
Adjustments to reconcile profit/loss to net cash flow:			
Depreciation	21,383	23,138	22,545
Foreign exchange differences	82	(48)	171
Finance expenses	25,279	25,730	25,504
Impairment charges	-	4,665	-
Changes in assets and liabilities:			
Inventory	(63)	-	-
Trade and other account receivables	(9,226)	1,787	(1,504)
Other current assets	19	-	102
Trade payables and other current liabilities	(1,517)	(983)	3,699
Other non-financial assets and liabilities	(19)	(1,499)	147
Account receivable and payable with related entities	(14)	(2,519)	-
Interest paid	(22,234)	(21,954)	(22,042)
Net cash flow generated by operating activities	**2,919**	**7,875**	**8,203**
Cash flows from investment activities			
Acquisition of property, plant, equipment and intangibles	(74)	(88)	(930)
(Purchase of) proceeds from short-term investments, net	-	3,526	(3,526)
Net cash flow generated by (used in) investment activities	**(74)**	**3,438**	**(4,456)**
Cash flows from financing activities			
Reduction of capital	(3,200)	-	(24,603)
Payment of principal portion of lease liabilities	(343)	(327)	-
Repayment of borrowings	(10,367)	(5,871)	(801)
Net cash flows used in financing activities	**(13,910)**	**(6,198)**	**(25,404)**
Effect of changes in exchange rates on cash and cash equivalents	-	-	-
Net increase (decrease) in cash and cash equivalents	**(11,065)**	**5,115**	**(21,657)**
Opening balance of cash and cash equivalents	**18,428**	**13,313**	**34,970**
Closing balance of cash and cash equivalents	**7,363**	**18,428**	**13,313**

Notes to the Consolidated Financial Statements

1. Reporting entity

Inversiones Latin America Power Ltda. (hereinafter "ILAP" or the "Company"), is a limited liability company incorporated by public deed dated June 14, 2013, under Notarial Record No. 10077-2013 whose business purpose is: a) making investments in all kinds of assets, whether movable or immovable, tangible or intangible, including the acquisition of shares or rights in partnerships, debentures, bonds, commercial papers, and all kinds of securities, and investment instruments, as well as the administration of said investments and its returns; and b) in general, any other investment activity.

Inversiones Latin America Power Ltda. is part of Latin America Power Group ("LAP Group") and is directly controlled by Latin América Power S.A., which is a closely-held corporation domiciled in Chile. Latin America Power S.A. is controlled by Latin America Power Holding B.V., a company incorporated on February 20, 2012 and domiciled in the Netherlands, which is the ultimate parent of the LAP Group (hereinafter, along with all its subsidiaries, the "LAP Group").

2. Significant accounting policies

2.1 Basis of preparation

d) Statement of compliance and basis of presentation

These consolidated financial statements include the consolidated statements of financial position as of December 31, 2020 and 2019, and the related consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2020, 2019 and 2018 of the Company and its subsidiaries (the "Group"). These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board (IASB) and fairly present the financial position of the Group as of December 31, 2020 and 2019 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020.

Note 2.2 describes main accounting policies adopted in the preparation of these consolidated financial statements. These policies have been defined based on IFRS in effect as of December 31, 2020, and have been consistently applied in all periods presented in these consolidated financial statements, except for the effects of adoption of IFRS 16 *Leases*, which the Company applied using the modified retrospective method and consequently recognized accumulated balances of the right-of-use asset and related lease liability as of 1 January 2019.

As of December 31, 2020, the Group presents a negative working capital of ThUS$ 10,129. Management expects the Company to generate sufficient cash flows from its normal business operations to meet its obligations and, in addition, it expects to count on the financial support of LAP Group. Additionally, the Group is currently searching for different alternatives to monetize the non-current accounts receivables related to the Price Stabilization Law (PEC) (see Note 12)). These financial statements were prepared on the basis of the continuity of the Company as a going concern.

The financial statements are presented in thousands of US dollars ("ThUS$"), unless otherwise stated. US dollar is functional currency of the Company and its subsidiaries.

These consolidated financial statements have been approved and authorized by Management for issuance on June 1, 2021.

e) Basis of measurement

The consolidated financial statements have been prepared on a historical cost basis.

f) Basis of consolidation

ILAP considers that it controls an investee when is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if it has all the following: (a) power over the investee; (b) exposure, or rights, to variable returns from its involvement with the investee; and (c) the ability to use its power over the investee to affect its returns.

In the case of the Group, the power over its subsidiaries is derived from the possession of practically total of the voting rights.

The Group re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of are included in the consolidated financial statements from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (“OCI”) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group’s accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction.

If the Group loses control over a subsidiary, it derecognizes the related assets (including goodwill), liabilities, non-controlling interest and other components of equity, while any resultant gain or loss is recognized in profit or loss. Any investment retained is recognized at fair value.

The following subsidiaries are included in these consolidated financial statements:

Country of incorporation	Entity	Participation	Status
Chile	Norvind S.A. (“Norvind”)	99,99%	Operating
Chile	San Juan S.A. ("San Juan")	99.999998%	Operating

San Juan S.A. operates Parque Eólico San Juan (193.20 MW of installed capacity), located in the province of Coquimbo, IV Region, Chile, since March 2017.

Norvind S.A. operates Parque Eólico Totoral (46 MW of installed capacity), located in Canela, Coquimbo Region, since January 2010.

Transactions eliminated on consolidation

Intra-group balances and transactions, and any unrealized income and expenses arising from intra-group transactions, are eliminated in preparing the consolidated financial statements. Unrealized gains arising from transactions with equity-accounted investees are eliminated against the investment to the extent of the Group’s interest in the investee. Unrealized losses are eliminated in the same way as unrealized gains, but only to the extent that there is no evidence of impairment.

2.2 Summary of significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, except as otherwise stated, and have been applied consistently by all entities consolidated within the Group.

a) New IFRS pronouncements in effect since January 1, 2020

The Company applied certain standards, interpretations and amendments for the first time, which are effective for annual periods beginning on or after January 1, 2020. The standards, interpretations and amendments to IFRS that went into effect as of the date of the financial statements, as well as their nature and impact, are detailed below.

	Standards and Interpretations	Date of mandatory application
Conceptual framework	Conceptual Framework (revised)	January 1, 2020

Conceptual Framework (revised)

The IASB issued the Conceptual Framework (revised) in March 2018. It incorporates new concepts, provides updated definitions and recognition criteria for assets and liabilities, and clarifies some important concepts.

Changes to the Conceptual Framework may affect the application of IFRS when no standard applies to a particular transaction or event. The revised Conceptual Framework goes into effect for periods that begin on or after January 1, 2020. These amendments had no impact on the consolidated financial statements of the Group.

	Amendments	Date of mandatory application
IFRS 3	Definition of a Business	January 1, 2020
IAS 1 e IAS 8	Definition of Material	January 1, 2020
IFRS 9, IAS 39 e IFRS 7	Interest Rate Benchmark Reform	January 1, 2020
IFRS 16	COVID-19-Related Rent Concessions	January 1, 2020

IFRS 3 Business Combinations – Definition of a Business

The IASB issued amendments to the definition of a business in IFRS 3 *Business Combinations* to help entities determine whether or not an acquired set of activities and assets is a business. The IASB clarifies the minimum requirements to define a business; eliminates assessment of whether market participants are able to replace any missing elements; includes guidance to assist entities in assessing whether an acquired project is substantive; narrows the definition of a business and of products; and introduces an optional fair value concentration test.

The amendments must be applied to the business combinations or asset acquisitions for which the acquisition date is on or after the beginning of the first annual reporting period that begins on or after January 1, 2020. Therefore, entities do not have to revisit transactions occurred in prior periods. Early application is permitted and must be disclosed.

These amendments had no impact on the consolidated financial statements of the Group, but may impact future periods should the Group enter into any business combinations.

IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors - Definition of Material

In October 2018, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors,* to align the definition of "material" in all standards and clarify certain aspects of the definition. The new definition establishes that information is material if omitting, misstating or obscuring it could reasonably be expected to influence the decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity. The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to the Group.

IFRS 9, IAS 39 and IFRS 7 Interest Rate Benchmark Reform

In September 2019, the IASB issued amendments to IFRS 9, IAS 39, and IFRS 7, finalizing Phase I of the project to address the effects of the reform to interbank offered rates (IBORs) in financial reporting. The amendments provide a number of reliefs, which apply to all hedging relationships that are directly affected by interest rate benchmark reform. A hedging relationship is affected if the reform gives rise to uncertainty about the timing and/or amount of benchmark-based cash flows of the hedged item or the hedging instrument. These amendments have no impact on the consolidated financial statements of the Group.

IFRS 16 COVID-19-Related Rent Concessions

In May 2020, the IASB issued an amendment to IFRS 16 Leases ("IFRS 16") to provide relief to lessees applying IFRS 16 guidance in connection with lease modifications and rent concessions that occur as a direct consequence of COVID-19 pandemic. The amendment does not apply to lessors.

The amendments provide relief to lessees from applying IFRS 16 guidance on lease modification accounting for rent concessions arising as a direct consequence of the Covid-19 pandemic. As a practical expedient, a lessee may elect not to assess whether a Covid-19 related rent concession from a lessor is a lease modification. A lessee that makes this election accounts for any change in lease payments resulting from the Covid-19 related rent concession the same way it would account for the change under IFRS 16, if the change were not a lease modification.

The amendment applies to annual reporting periods beginning on or after 1 June 2020. Earlier application is permitted. This amendment had no impact on the consolidated financial statements of the Group.

b) Foreign currency

Transactions in a foreign currency (currency different from the functional currency) are converted into the functional currency of the Company at the dates of the transactions (the main non-dollar currency used by the Company is the Chilean peso). Losses and profits resulting from the settlement of balances related to these transactions and from conversion, at the closing rate, of monetary assets and liabilities denominated in a foreign currency and existing at the reporting date, are recognized in the income statement within the "Exchange differences" heading.

The exchange rates of the Chilean peso (CLP) as of December 31st, 2020 and 2019 are as follows:

Date	Currency	Exchange Rate
December 31, 2020	USD 1	CLP 710.95
December 31, 2019	USD 1	CLP 748.74

c) Business combinations, goodwill and acquisition of non-controlling interests

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at acquisition date fair value, and the amount of any non-controlling interests in the acquiree. For each business combination, the Group elects whether to measure the non-controlling interests in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

Goodwill is initially measured at cost (being the excess of the aggregate of the consideration transferred and the amount recognized for non-controlling interests and any previous interest held over the net identifiable assets acquired and liabilities assumed). If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group re-assesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognized at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognized in profit or loss.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a cash-generating unit (CGU) and part of the operation within that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the cash-generating unit retained.

A contingent liability recognised in a business combination is initially measured at its fair value. Subsequently, it is measured at the higher of the amount that would be recognised in accordance with the requirements for provisions in IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* or the amount initially recognised less (when appropriate) cumulative amortisation recognised in accordance with the requirements for revenue recognition.

d) Cash and cash equivalents

Cash and cash equivalents include cash in hand and demand deposits in financial institutions. They also include other short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. An investment normally qualifies as a cash equivalent when it has a maturity of less than three months from the date of acquisition.

e) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity.

The Company´s non-derivative financial instruments comprise mainly trade and other receivables, cash and cash equivalents, loans and borrowings, and trade and other payables.

(i) Financial assets

Financial assets are classified, at initial recognition, as subsequently measured at amortized cost, fair value through OCI, and fair value through profit or loss. The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing them. With the exception of trade receivables that do not contain a significant financing component, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs. Trade receivables that do not contain a significant financing component are measured at the transaction price determined under IFRS 15.

In order for a financial asset to be classified and measured at amortized cost or fair value through OCI, it needs to give rise to cash flows that are 'solely payments of principal and interest ("SPPI")' on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Company's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.
Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the market place (regular way trades) are recognized on the trade date, i.e., the date that the Company commits to purchase or sell the asset.

For purposes of subsequent measurement, financial assets are generally classified in four categories:

- Financial assets at amortized cost (debt instruments);
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments);
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments); and
- Financial assets at fair value through profit or loss.

The Company has currently only instruments classified to the categories of financial assets at amortized cost and minor financial assets at fair value through profit or loss. All derivative instruments are designated hedging instruments in hedge relationships and are accounted in accordance with the policy applicable for hedge accounting described further in this Note.

Financial assets at amortized cost (debt instruments)

The Company measures financial assets at amortized cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows, and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets at amortized cost are subsequently measured using the effective interest (“EIR”) method and are subject to impairment. Gains and losses are recognized in profit or loss when the asset is derecognized, modified or impaired.

The Company’s financial assets at amortized cost includes mainly trade and other receivables, including those due from related parties.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading, financial assets designated upon initial recognition at fair value through profit or loss, or financial assets mandatorily required to be measured at fair value. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments. Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at fair value through profit or loss, irrespective of the business model.

Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value recognized in the statement of profit or loss.

A derivative embedded in a hybrid contract, with a financial liability or non-financial host, is separated from the host and accounted for as a separate derivative if: the economic characteristics and risks are not closely related to the host; a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and the hybrid contract is not measured at fair value through profit or loss. Embedded derivatives are measured at fair value with changes in fair value recognized in profit or loss. Reassessment only occurs if there is either a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required or a reclassification of a financial asset out of the fair value through profit or loss category.

A derivative embedded within a hybrid contract containing a financial asset host is not accounted for separately. The financial asset host together with the embedded derivative is required to be classified in its entirety as a financial asset at fair value through profit or loss.

Derecognition

A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognized (i.e., removed from the Group’s consolidated statement of financial position) when:

- The rights to receive cash flows from the asset have expired or
- The Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Company has transferred substantially all the risks and rewards of the asset, or (b) the Company has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

Impairment of financial assets

The Company recognizes an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognized in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12-months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Company applies a simplified approach in calculating ECLs. Therefore, the Company does not track changes in credit risk, but instead recognizes a loss allowance based on lifetime ECLs at each reporting date. The Company has established a provision matrix that is based on its historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Company generally considers a financial asset in default when contractual payments are 12 months past due. However, in certain cases, the Company may also consider a financial asset to be in default when internal or external information indicates that the Company is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Company. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

(ii) Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, trade payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognized initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowings including bank overdrafts and derivative financial instruments.

The measurement of financial liabilities depends on their classification, as described below:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Company that are not designated as hedging instruments in hedge relationships as defined by IFRS 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognized in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in IFRS 9 are satisfied. The Company has not designated any financial liability as at fair value through profit or loss.

Loans and borrowings and trade payables

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortized cost using the EIR method. Gains and losses are recognized in profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

Amortized cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortization is included as finance costs in the statement of profit or loss. This category generally applies to interest-bearing loans and borrowings.

A financial liability is derecognized when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognized in the statement of profit or loss.

f) Property, plant and equipment

Land, construction in progress, plant and equipment are stated at cost, net of accumulated depreciation and accumulated impairment losses, if any. Such cost includes the cost of replacing part of the plant and equipment and borrowing costs for long-term construction projects if the recognition criteria are met. When significant parts of plant and equipment are required to be replaced at intervals, the Group depreciates them separately based on their specific useful lives. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the plant and equipment as a replacement if the recognition criteria are satisfied. All other repair and maintenance costs are recognized in profit or loss as incurred.

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets, as follows:

Property, plant and equipment	Years
Towers and Control Rooms	25
Wind turbines	20
Technical facilities	20

Land is not depreciated.

An item of property, plant and equipment and any significant part initially recognized is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement or profit or loss when the asset is derecognized.

The residual values, useful lives and methods of depreciation of property, plant and equipment are reviewed at each financial year end and adjusted prospectively, if appropriate.

The present value of the expected cost for the decommissioning of an asset after its use is included in the cost of the respective asset if the recognition criteria for a provision are met. Refer to significant accounting judgements, estimates and assumptions (Note 3) and provisions (Note 16) for further information about the recognized decommissioning provision.

g) Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale are capitalized as part of the cost of the asset. All other borrowing costs are expensed in the period in which they occur. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

h) Impairment of non-financial assets

The Group assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Group estimates the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's or cash generating unit's ("CGU") fair value less costs of disposal and its value in use. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets.

When the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs of disposal, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model is used. The models that the Group uses are based on the discounted cash flows methodology. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded companies or other available fair value indicators.

Each of the CGU's recoverable amounts which are subject to impairment test periodically, are estimated through the fair value less costs of disposal according to IFRS 13 *Fair Value measurement* and compared with the recoverable amount of the respective CGU. The Group bases its impairment calculation on detailed budgets and forecast calculations, which are prepared separately for each of the Group's CGUs to which the individual assets are allocated. These budgets and forecast calculations generally cover a period equal to estimated useful lives of the respective assets (power plants).

Impairment losses of continuing operations are recognized in the statement of profit or loss in expense categories consistent with the function of the impaired asset.

For assets excluding goodwill, an assessment is made at each reporting date to determine whether there is an indication that previously recognized impairment losses no longer exist or have decreased. If such indication exists, the Group estimates the asset's or CGU's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in the statement of profit or loss unless the asset is carried at a revalued amount, in which case, the reversal is treated as a revaluation increase.

Goodwill is tested for impairment annually as at 31 December and when circumstances indicate that the carrying value may be impaired.

Impairment is determined for goodwill by assessing the recoverable amount of each CGU (or group of CGUs) to which the goodwill relates. When the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognized. Impairment losses relating to goodwill cannot be reversed in future periods.

Intangible assets with indefinite useful lives are tested for impairment annually as at 31 December at the CGU level, as appropriate, and when circumstances indicate that the carrying value may be impaired.

i) Provisions

A provision is recognized, as a result of a past event, if ILAP Group has a present (legal or constructive) obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. When the effect of the time value of money is significant, the amount of the provision is the present value of expenses expected to be incurred to pay the obligation.

If the ILAP Group has an evidence that a provision can be reimbursed, e.g. those cases covered by an insurance policy, the reimbursement is recognized separately as an asset only when it is effectively probable that reimbursement will be received.

Every six months, the legal department of the Company meets its legal counsel and analyzes the potential liabilities or claims that may be received by the Company. If it is determined that the probability of an adverse outcome is more than 50%, a provision is recognized and measured based on the best available estimate.

j) Revenue and expense recognition

Revenue

Revenue is earned from the production and sale of energy (electricity) and capacity from the Group's generation plants. Revenue is recognized upon the transfer of control of promised goods or services to customers in an amount that reflects the consideration to which the Group is expected to be entitled in exchange for those goods or services. Revenue is recorded net of any taxes assessed on and collected from customers.

The Company provides the service of energy and capacity supply to unregulated (free) and regulated customers. The revenues are recognized based on the physical delivery of energy and capacity. The services are satisfied over time as the client receives simultaneously and consumes the benefits provided by the Company. Consequently, the Company recognizes the revenue for these service contracts grouped over time instead of at a point of time.

Revenue from sales to regulated customers (distribution companies) and free customers (usually industrial clients) are recorded on the basis of physical delivery of energy and capacity, in accordance with long-term power purchase agreements ("PPAs"). Revenues from energy and capacity sales on the spot market are recorded on the basis of physical delivery, to other generating companies, at the marginal cost of energy and capacity. The spot market by respective laws is organized through Dispatch Centers (CEN) where the surpluses and deficits of energy and capacity are settled. Energy and capacity surpluses are recorded as revenues and deficits are recorded as cost of sales within the consolidated statement of profit or loss.

Revenue from generation contracts is recognized using an output method, as energy and capacity delivered best depicts the transfer of goods or services to the customer. Capacity, which is a stand-ready obligation to deliver energy when required by the customer, is measured based on the availability of the generation plants.

k) Finance income and finance costs

Finance income comprises interest income on funds invested, and fair value gains on financial assets at fair value through profit or loss. Interest income is recognized in profit or loss at amortized cost using the effective interest method. Finance cost comprise interest expense on borrowings, impairment losses recognized on financial assets (other than trade receivables) and reclassifications of amounts previously recognized in other comprehensive income.

Borrowing costs that are not directly attributable to the acquisition, construction or production of a qualifying asset are recognized in profit or loss using the effective interest method.

Foreign currency gains and losses are reported on a net basis as either finance income or finance cost depending on whether foreign currency movements are in a net gain or net loss position.

l) Income taxes

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Group operates and generates taxable income.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the statement of profit or loss. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax is provided using the liability method on temporary differences between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date.

Deferred tax liabilities are recognized for all taxable temporary differences, except:

- When the deferred tax liability arises from the initial recognition of goodwill or an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss;
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, when the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future

Deferred tax assets are recognized for all deductible temporary differences, the carry forward of unused tax credits and any unused tax losses. Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry forward of unused tax credits and unused tax losses can be utilized, except:

- When the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss;
- In respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized outside profit or loss is recognized outside profit or loss. Deferred tax items are recognized in correlation to the underlying transaction either in OCI or directly in equity.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognized subsequently if new information about facts and circumstances change. The adjustment is either treated as a reduction in goodwill (as long as it does not exceed goodwill) if it was incurred during the measurement period or recognized in profit or loss.

Uncertain tax positions

In determining the amount of current and deferred taxes ILAP Group takes into account the impact of uncertain tax positions and whether additional taxes and interest may be due. ILAP Group believes that its accruals for tax liabilities are adequate for all open tax years based on its assessments of various factors, including interpretations of tax laws and prior experience. This assessment relies on estimates and assumptions and may involve a series of judgments about future events. New information may become available that causes the Group to change its judgment regarding the adequacy of existing tax liabilities; such changes to tax liabilities will impact tax expense in the period when such a determination is made.

m) Current versus non-current classification

The Group presents assets and liabilities in statement of financial position based on current/non-current classification. An asset is presented as current when it is:

- Expected to be realized or intended to sold or consumed in normal operating cycle
- Held primarily for the purpose of trading
- Expected to be realized within twelve months after the reporting period, or
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least twelve months after the reporting period.

All other assets are classified as non-current.

A liability is current when:

- It is expected to be settled in normal operating cycle
- It is held primarily for the purpose of trading
- It is due to be settled within twelve months after the reporting period, or
- There is no unconditional right to defer the settlement of the liability for at least twelve months after the reporting period.

The Group classifies all other liabilities as non-current.

Deferred tax assets and liabilities are classified as non-current assets and liabilities.

n) Fair value measurement

The Group measures financial instruments such as derivatives, at fair value at each balance sheet date. Fair-value related disclosures for financial instruments and non-financial assets that are measured at fair value or where fair values are disclosed are summarized in the following notes:

- Disclosures for valuation methods, significant estimates and assumptions (Note 8.c)
- Quantitative disclosures of fair value measurement hierarchy

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability

The principal or the most advantageous market must be accessible by the Group.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.
The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level input that is significant to the fair value measurement as a whole:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

For assets and liabilities that are recognized in the financial statements at fair value on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

For the purpose of fair value disclosures, the Group has determined classes of assets and liabilities on the basis of the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy, as explained above.

o) Leases

Under IFRS 16 *Leases*, the Group assesses at contract inception whether a contract is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

In the periods covered by these financial statements the Group has no contracts in which it acts as a lessor.

Acting as a lessee, the Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. The Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

<u>Right-of-use assets</u>

The Group recognises right-of-use assets at the commencement date of the lease (i.e., the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Right-of-use assets are depreciated on a straight-line basis over the shorter of the lease term and the estimated useful lives of the assets,

If ownership of the leased asset transfers to the Group at the end of the lease term or the cost reflects the exercise of a purchase option, depreciation is calculated using the estimated useful life of the asset. The right-of-use assets are also subject to impairment. Refer to the accounting policies in section i) Impairment of non-financial assets above.

The right-of-use assets are presented in the statement of financial position within Property, plant and equipment (see Note 7).

<u>Lease liabilities</u>

At the commencement date of the lease, the Group recognizes lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in-substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating the lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognized as expenses in the period in which the event or condition that triggers the payment occurs.

In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

The Group's lease liabilities are presented separately in the statement of financial position as Lease liabilities (see Note 10).

3. Significant accounting judgments, estimates and assumptions

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses, and the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The most important estimates used are:

- Impairment of non-current assets, including goodwill: Management determines, at each accounting close, whether there are indicators of impairment, and if so, whether non-current assets are impaired. The goodwill impairment test is performed every year irrespectively if the impairment indicators are present. The impairment test requires an estimation of the value in use or fair value less costs of disposal of assets or cash generating units. Both methods require management to estimate the expected future cash flows from assets or CGUs and determine an appropriate discount rate to calculate the present value of these cash flows.

- Deferred tax assets: Deferred tax assets are recognized in respect of unused tax losses to the extent it is probable that taxable profit is available against which the Company can utilize the benefits therefrom. The Group develops projections of future taxable profits to assess such probability and also considers tax planning opportunities that the Company would take in order to create or increase taxable income in a particular period before the expiry of a tax loss or tax credit carryforward.

4. New and amended standards and interpretations

The standards and interpretations, and improvements and amendments to IFRS that have been issued, but have not yet come into effect as of the date of these financial statements, are detailed below. The Company has not applied these standards in advance:

	Standards and Interpretations	Date of Mandatory Application
IFRS 17	Insurance Contracts	January 1, 2023

IFRS 17 Insurance Contracts

In May 2017, the IASB issued IFRS 17 Insurance Contracts, a new insurance contract specific accounting standard that addresses recognition, measurement, presentation, and disclosure issues. After going into effect, it will supersede IFRS 4 Insurance Contracts issued in 2005. The new standard applies to all kinds of insurance contracts, regardless of the type of entity that issues them, as well as certain guarantees and financial instruments with specific discretionary participation features. Some exceptions within the scope might be applied.

IFRS 17 will be effective for periods beginning on or after January 1, 2023, and comparative figures are required. Early application is permitted as long as the entity also applies IFRS 9 Financial Instruments on or before IFRS 17 first application.

	Amendments	Date of Mandatory Application
IFRS 9, IAS 39, IFRS 7, IFRS 4 e IFRS 16	Interest Rate Benchmark Reform Phase 2	January 1, 2021
IFRS 3	Reference to the Conceptual Framework	January 1, 2022
IAS 16	Property, plant and equipment: proceeds before intended use	January 1, 2022
IAS 37	Onerous contracts – cost of fulfilling a contract	January 1, 2022
IAS 1	Classification of liabilities as current or non-current	January 1, 2023
IFRS 10 e IAS 28	Consolidated Financial Statements – sales or contributions of assets between and investor and its associates or joint ventures	To be determined

IFRS 9, IAS 39, IFRS 7, IFRS 4 e IFRS 16 Interest Rate benchmark Reform – Phase 2

In August 2020, the IASB issued the Interest Rate Benchmark Reform – Phase II that comprises amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16. Thus, the IASB finalizes its work to address the effects of the reform to interbank offered rates (IBORs) in financial reporting.

The amendments provide temporary exemptions that address the effects on financial reporting when interest rate benchmarks (IBORs) are replaced with alternative interest risk free rates.

Amendments are required and early application is permitted. A hedge relationship must be resumed if the hedge relationship was solely discontinued because of the changes implemented by the interest rate benchmark reform and thus, it would have not been discontinued if Phase II of the project had been applied then. While amendments must be applied retrospectively, an entity is not required to restate prior periods.

IFRS 3 Reference to the Conceptual Framework

In May 2020, the IASB issued amendments to IFRS 3 Business Combinations – Reference to the Conceptual Framework. These amendments will replace reference to a previous version of the IASB Conceptual Framework (1989 Framework) with a reference to the current version issued in March 2018, however, requirements have not substantially changed.

The amendments will be effective for periods beginning on or after January 1, 2022 and must be applied retrospectively. Early application is permitted if at the same time or earlier an entity also applies all the amendments contained in the amendments to the Reference to the Conceptual Framework of IFRS issued in March 2018.

The amendments will provide consistency in financial reporting and avoid potential confusion from having more than one version of the Conceptual Framework in use.

IAS 16 Property, plant and equipment: Proceeds Before Intended Use

This standard prohibits entities from deducting from the cost of an item of property, plant and equipment, any sale while bringing the asset to the location and conditions necessary for the asset to be capable of operating as intended by management. Instead, an entity will recognize the proceeds from a sale and cost of these elements in the income for the period, in accordance with the applicable Standards.

The amendment will be effective for periods beginning on or after January 1, 2022. The amendment shall be applied retrospectively only to the elements of property, plant and equipment available for use on or after the beginning of the first period presented in the financial statements of the entity applying the amendment for the first time.

IAS 37 Onerous contracts – Cost of fulfilling a contract

In May 2020, the IASB issued amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify the costs that an entity should include when assessing whether a contract is onerous or triggers losses.

The amendment is effective for periods beginning on or after January 1, 2022. The amendment shall be applied retrospectively to existing contracts at the beginning of the annual reporting period in which the entity applies the amendment for the first time (date of initial application). Early application is permitted and must be disclosed.

The amendments are intended to provide clarity and help to ensure a consistent application of the standard. Entities that have previously applied the incremental cost approach, will see an increase in provisions to reflect the inclusion of costs directly related to the contract activities, while entities that have previously recognized allowances for contractual losses based on the previous standard guidance, IAS 11 Construction Contracts, shall exclude the indirect cost allocation from their provisions.

IAS 1 Presentation of Financial Statements – Classification of liabilities as current or non-current

In June 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classification of liabilities as current or non-current.

The amendments are effective for periods beginning on or after January 1, 2022. Entities must carefully evaluate whether any aspect of the amendments might suggest that the terms of their existing loan agreements should be renegotiated. In this context, it is worth noting that amendments shall be applied retrospectively.

IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures– sale or contribution of assets between an investor and its associate or joint venture

The amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures (2011) address an inconsistency recognized between the requirements of IFRS 10 and those of IAS 28 (2011) in the treatment of the sale or contribution of assets between an investor and its associate or joint venture. Amendments issued in September 2014 establish that when the transaction involves a business (found in a subsidiary or not), a complete profit or loss is recognized. A partial profit or loss is recognized when the transaction involves assets that do not constitute a business, even when the assets are found in a subsidiary. The date of mandatory application of these amendments is yet to be determined, because the IASB is waiting for the results of its investigation project on the accounting using the equity method. The amendments must be applied retrospectively and early adoption is permitted, which must be disclosed.

5. Regulation and Operation of the Power System

The electric sector in Chile is regulated by the General Electricity Services Act contained in DFL No. 1 of 1982 of the Ministry of Mining, whose consolidated and coordinated text was set by DFL No. 4 of 2006 of the Ministry of Economy ("Electricity Act") and its corresponding Regulations, contained in DS No. 327 of 1998. Three government entities have the responsibility for the implementation and enforcement of the Electricity Act: the National Energy Commission ("CNE", for its acronym in Spanish for *Comisión Nacional de Energía*), which has the authority to propose regulated tariffs (node prices) and to develop indicative plans for the construction of new generating units; the Superintendence of Electricity and Fuels ("SEC", for its acronym in Spanish for *Superintendencia de Electricidad* *y Combustibles*), which supervises and monitors compliance with laws, regulations and technical standards for the generation, transmission and distribution of electricity, liquid fuels and gas; and finally, the Ministry of Energy, created in 2009, which is responsible for proposing and conducting public policies on energy matters and brings under his authority the SEC, the CNE and the Chilean Nuclear Energy Commission (CChEN, for its acronym in Spanish for *Comisión Chilena de Energía Nuclear*) strengthening coordination and facilitating a comprehensive view of the sector. The Act also features an Agency for Energy Efficiency and the Renewable Energy Center. The act also establishes an Expert Panel whose main function is to solve discrepancies that occur between actors in the electric market: electricity companies, system operator, regulator, etc.

From a physical standpoint, the Chilean electric sector is divided into three electric systems: the SEN ("SEN" for its acronym in Spanish for *Sistema Eléctrico Nacional*), and two isolated small systems: Aysén and Magallanes. The SEN, main electrical system, extends longitudinally for 3,100 km. It is composed of the former Central Interconnected system (SIC for its acronym in Spanish for *Sistema Interconectado Central*) and Norte Grande Interconnected system (SING for its acronym in Spanish for *Sistema Interconectado del Norte Grande*). As of December 2020 it has a net installed capacity of 25,373 MW.

The organization of Chilean electric industry mainly distinguishes three activities, which are: generation, transmission and distribution, which operate in an interconnected and coordinated manner, and whose main objective is to provide electrical energy to the market at minimum cost and preserving standards of quality and safety of service required by electrical regulations. Due to its characteristics, transmission and distribution activities are natural monopolies, reason why these are segments regulated as such by electrical regulation, requiring open access to networks and definition of regulated tariffs.

According to the Electricity Act, companies involved in generation and transmission in an interconnected power system must centrally coordinate their operations through an operating entity, the National Electric Coordinator (CEN for its acronym in Spanish for *Coordinador Eléctrico Nacional*) in order to operate the system at minimum cost while preserving service security. For this, the CEN plans and performs the operation of the system, including the calculation of hourly marginal cost, price at which energy transfers made between generators in the CEN are valued (spot market).

Therefore, the decision of generation of each company is subject to CEN's operating plan. Each company, in turn, can freely decide whether to sell its energy to regulated or unregulated customers. Any surplus or deficit between their sales to customers and their production is sold to or bought from other generators at spot market price.

A generating company may have the following types of customers:

a) **Regulated customers**

Correspond to those small and medium industries, residential and commercial consumers whose connected capacity is less than or equal to 500 kW, and which are located in the concession area of a distribution company. In this case the distribution company acts as buyer to the generating company. Customers with consumptions between 500 kW and 2,000 kW may opt between the regulated or unregulated pricing mechanism. Until 2009, the price of energy transfer between generators and distribution companies to supply regulated customers had a maximum value called the node price, which is regulated by the Ministry of Energy. Node prices are determined every six months (April and October), according to a report issued by the CNE, based on projections of marginal costs of the system expected for the following 48 months. From 2010, and as the validity term of agreements at node price is expiring, this transfer price between generation and distribution companies is replaced by the result of tenders conducted in a regulated process, with a maximum price set by the authority every six months.

b) **Unregulated customers**

Corresponds to that portion of the demand that has a connected capacity of more than 2,000 kW, mainly industrial and mining clients. These consumers may freely negotiate their prices of power supply with generators and/or distributors. Customers with capacity between 500 and 2,000 kW, as noted in the previous section, have the option to contract energy at prices that can be agreed with their suppliers or remain subject to regulated prices, for a minimum period of four years in each regime.

c) **Short-term or spot market**

Corresponds to energy and power transactions between generating companies, resulting from the coordination made by the CEN in order to achieve the economic operation of the system, and the excess (deficit) of its production regarding its commercial commitments is transferred through sales (purchases) to other generators coordinated by the CEN. In the case of energy, transfers are valued at marginal cost and in the case of power (*capacity or "potencia"*), at the corresponding node price, according to the price set semiannually by the authority. The capacity payable to each generator depends on a calculation made centrally by the CEN annually, thus obtaining the firm capacity of each plant, a value that is independent of its dispatch.

Since 2010, with the enactment of Law 20,018, which changed the regulatory framework for the electricity sector, distribution companies must ensure an uninterrupted supply for its total demand projected to three years, for which long-term public tender processes shall be conducted.
In renewable energy matters, Law 20,257 was enacted in April 2008, introducing amendments to the Electricity Law with respect to the generation of electricity from Non-Conventional Renewable Energy sources (ERNC, for its acronym in Spanish). The main aspect of this Act is that it forces generators to ensure that -at least- 5% of its energy sold to customers comes from these renewable sources, between 2010 and 2014, progressively increasing in 0.5% from year 2015 until 2024, when a 10% will be achieved. The CEN, with information on actual operation and contracts reported by generating companies, conducts annual balances to verify compliance with this Act.

In October 2013, Development Incentive Act of ERNC was amended, increasing the level of requirement to generators with contracts executed after July 1st, 2013, so that the percentage to be supplied with this kind of technologies progressively reaches a 20% by 2025. This requirement is not imposed on agreements executed prior to that date, to which shall apply the mandates established in Law 20,257 of 2008. Additionally, if the regulator foresees that the encouraged development due to market signals is an insufficient incentive to comply with percentages intended by this act, an obligation for the Ministry of Energy was introduced, to conduct Public Tenders in order to award 12-year power purchase agreements to ERNC projects.

6. Cash and cash equivalents

As of December 31, 2020 and 2019, the composition of cash and cash equivalents is as follows:

ThUS$	December	
	2020	2019
Bank balances	7,363	18,428
TOTAL	**7,363**	**18,428**

Bank balances consists of current accounts. There are no restrictions to these balances.

The breakdown by currency of cash and cash equivalents is detailed as follows:

ThUS$	December		
	USD	CLP	Total
December 31, 2020	3,383	3,980	7,363
December 31, 2019	12,145	6,283	18,428

7. Property, plant and equipment

a) Movements

The movements during 2020 and 2019 are as follows:

2020	ThUS$			
	Beginning balance	Additions	Adjustments /Transfers	Ending balance
Cost				
Land	10,705	-	-	**10,705**
Right-of-use assets (*)	12,684	-	-	**12,684**
Infrastructure	42,744	-	-	**42,744**
Machinery and equipment	364,773	25	-	**364,798**
Civil works	45,860	-	-	**45,860**
Other equipment	1,998	15	-	**2,013**
Furniture and fittings	168	-	-	**168**
Decommissioning costs	48,994	-	-	**48,994**
Work in progress	859	34	(192)	**701**
Total Cost	**528,785**	**74**	**(192)**	**528,667**
Accumulated Depreciation				
Infrastructure	(10,289)	(1,829)	-	**(12,118)**
Right-of-use assets (*)	(588)	(588)	-	**(1,176)**
Machinery and equipment	(89,615)	(14,790)	-	**(104,405)**
Civil works	(6,635)	(2,012)	-	**(8,647)**
Other equipment	(737)	(147)	-	**(884)**
Furniture and fittings	(155)	(5)	-	**(160)**
Decommissioning costs	(4,009)	(2,004)	-	**(6,013)**
Total Accumulated Depreciation	**(112,028)**	**(21,375)**	**-**	**(133,403)**
Net Carrying Amount	**416,757**	**(21,301)**	**(192)**	**395,264**

(*) Includes right-of-use of a land recognized under IFRS 16.

2019	ThUS$			
	Beginning balance	Additions	Adjustments /Transfers	Ending balance
Cost				
Land	10,705	-	-	**10,705**
Right-of-use assets (*)	-	12,684	-	**12,684**
Infrastructure	42,744	-	-	**42,744**
Machinery and equipment	364,773	-	-	**364,773**
Civil works	45,860	-	-	**45,860**
Other equipment	1,998	-	-	**1,998**
Furniture and fittings	168	-	-	**168**
Decommissioning costs	48,994	-	-	**48,994**
Work in progress	964	-	(105)	**859**
Total Cost	**516,206**	**12,684**	**(105)**	**528,785**
Accumulated Depreciation				
Infrastructure	(8,615)	(1,674)	-	**(10,289)**
Right-of-use assets (*)	-	(588)	-	**(588)**
Machinery and equipment	(72,981)	(16,634)	-	**(89,615)**
Civil works	(4,515)	(2,120)	-	**(6,635)**
Other equipment	(633)	(104)	-	**(737)**
Furniture and fittings	(150)	(5)	-	**(155)**
Decommissioning costs	(2,004)	(2,005)	-	**(4,009)**
Total Accumulated Depreciation	**(88,898)**	**(23,130)**	**-**	**(112,028)**
Net Carrying Amount	**427,308**	**(10,446)**	**(105)**	**416,757**

(*) Includes right-of-use of a land recognized under IFRS 16.

b) **Other Matters**

In management's opinion, insurance policies taken are in accordance with the standards used by other companies in the industry and adequately cover potential losses for catastrophic events that may affect the assets owned by the Group.

As of December 31, 2020 and 2019, Parque Eólico Totoral owned by Norvind S.A. and Parque Eólico San Juan owned by San Juan S.A. assets are pledged to secure the Notes issued by ILAP (see Note 14).

Borrowing costs: During 2020 and 2019 the Group did not capitalize any borrowing costs. Borrowing costs incurred and capitalized in prior years are included in the initial cost of machinery and equipment. Each entity in charge of constructing the power plant took its own debt, so all the borrowing costs were specific and, as a consequence, 100% of such borrowing costs were capitalized during respective construction periods.

8. Intangible assets and goodwill

a) Intangible assets other than goodwill

The composition and movements in intangible assets other than goodwill during 2020 and 2019 are as follows:

2020	Th$USD			
	Beginning balance	Additions	Adjustments/ Transfers	Ending balance
Cost				
Project development costs	82	-	-	82
Easements	449	-	-	449
Total Cost	**531**	**-**	**-**	**531**
Accumulated Amortization				
Project development costs	(32)	(8)	-	(40)
Total Accumulated Amortization	**(32)**	**(8)**	**-**	**(40)**
Net Carrying Amount	**499**	**(8)**	**-**	**491**

2019	Th$USD			
	Beginning balance	Additions	Adjustments/ Transfers	Ending balance
Cost				
Project development costs	82	-	-	82
Easements	449	-	-	449
Total Cost	**531**	**-**	**-**	**531**
Accumulated Amortization				
Project development costs	(24)	(8)	-	(32)
Total Accumulated Amortization	**(24)**	**(8)**	**-**	**(32)**
Net Carrying Amount	**507**	**(8)**	**-**	**499**

b) Goodwill

As of December 31, 2020, the Company has no goodwill balance. During the year 2019 the entire goodwill balance related to Norvind CGU was impaired.

Goodwill	ThUS$		
	January 1, 2019	Impairment	December 31, 2019
Norvind	4,665	(4,665)	-

c) Impairment testing for CGUs containing goodwill

The Group performed its annual impairment test of goodwill as of December 31, 2019. Based on impairment test in 2019, Norvind's goodwill of ThUS$ 4,665 was written off.

For purposes of impairment testing, goodwill was allocated to Norvind cash-generating unit that was expected to benefit from the synergies of the respective business combination.

The recoverable amount Norvind was calculated based on their estimated fair value less costs of disposal, through estimated discounted cash flows of the Group's projections. The most important assumptions in the determination of the recoverable value were: (i) energy prices and consumption levels, and (ii) discount rates.

Discount rate used in the impairment test in 2019 represented the current market assessment of the risks specific to the CGU, taking into consideration the time value of money and individual risks of the underlying assets that have not been incorporated in the cash flow estimates. The discount rate calculation was based on the specific circumstances of the CGU's market and was derived from the weighted average cost of capital ("WACC"). The WACC takes into account both debt and equity from a market perspective. The cost of equity was derived from the expected return on investment by the Group's investors. The cost of debt was based on an intense quoting the Group has carried out during the period, in search for capital structure improvement (refinancing) and investment opportunities. Specific industry risk was incorporated by applying individual beta factors, which impacts directly the cost of equity. The beta factors were evaluated annually based on publicly available market data (Bloomberg). The discount rate used in the 2019 impairment test was 6.48%.

9. Inventory

This balance comprises the following:

Inventory	2020	2019
Spare Parts	63	-
Total	**63**	**-**

10. Leases

The Group has a lease contracts for the use of a land on which San Juan's wind farm is located for a period of twenty one years.

The carrying amounts of right-of-use assets recognized and the movements during the year 2020 are presented in the Note 7.

Set out below are the carrying amounts of lease liabilities from leases classified before adoption of IFRS 16 as operating leases and the movements during the period:

Lease Liabilities	2020	2019
Beginning balance	12,357	12,684
Accretion of interest	662	679
Amortization	(1,005)	(1,006)
Ending balance	**12,014**	**12,357**
Current	362	343
Non-current	11,652	12,014

The following are the amounts recognized in profit or loss in relation to those lease contracts:

Lease	2020	2019
Depreciation expense of right-of-use assets	(588)	(588)
Interest expense on lease liabilities	(662)	(679)
Variable lease payments	(1,548)	(1,143)
Total amount recognized in profit or loss	**(2,798)**	**(2,410)**

The San Juan lease contract contains variable payments based on the plant's generation. Management's objective is to align the lease expense with actual production and revenue earned.

Reconciliation of changes in lease liabilities to the cash flow statement are as follows:

Type of Liability	January 1, 2020	Cash Flows		Accrued interest	December 31, 2020
		Repayment	Interest paid		
Lease liabilities	12,357	(343)	(662)	662	12,014

Type of Liability	January 1, 2019	Cash Flows		Accrued interest	December 31, 2019
		Repayment	Interest paid		
Lease liabilities	12,684	(327)	(679)	679	12,357

11. Financial instruments and risk management

ILAP Group has exposure to the following risks arising from financial instruments:

- Credit risk
- Liquidity risk
- Market risk

The activities of ILAP Group expose it to a series of financial risks: market risks (including currency risk and interest rate risk), credit risk and liquidity risk. The Group's overall risk management program focuses mainly on the unpredictability of financial markets and seeks to minimize the potential adverse effects on its financial performance.

a) Risk management framework

Senior Management is responsible for establishing the risk management policies of the Group, which aim to identify, analyse and mitigate the main risks faced by the business.

The Group's risk management policies are established to identify and analyse the risks faced by the Group, to set appropriate risk limits and controls, and to monitor risks and adherence to limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Group's activities. ILAP Group, through its standards and procedures, aims to develop a disciplined and constructive control environment in which all employees understand their roles and responsibilities.

b) Credit risk

Credit risk is the risk of financial loss to the ILAP Group if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally on accounts receivable, investments in mutual funds and bank balances, including time deposits of the Group.

The ILAP Group's policies for managing credit risk of its customers include the assessment of financial information and the measurement of parameters such as liquidity and solvency. Trade receivables consist of balances due from creditworthy customers, including mainly large industrial clients, electricity distribution companies and other generation companies.

The ILAP Group invests in highly liquid instruments (time deposits at bank and money market mutual funds) held at premium financial institutions.

The carrying amounts of financial assets recorded in the financial statements represent the maximum exposure to credit risk of those instruments, as follows:

Types of assets	ThUS$	
	2020	2019
Cash and cash equivalents	7,363	18,428
Trade and other current receivables	10,565	11,836
Current receivables from related parties	3,836	3,643
Total Current Assets	**21,764**	**33,907**
Trade and other current receivables, non-current	11,742	1,245
Total Non-Currents Assets	**11,742**	**1,245**
Total	**33,506**	**35,152**

ILAP Group held cash and cash equivalents of ThUS$ 7,363 as of December 31, 2020, which represents its maximum credit exposure on these assets. Cash and cash equivalents are held with banks and financial institutions with a proven reputation.

Due to the nature of the business, trade and other receivables represent a very low risk for the Group as all participants in the electricity markets in Chile are by law obliged to pay their obligations in the following month after the energy is consumed. The counterparties to the Company's PPAs as well as other relevant electricity market participants generally possess high credit ratings.

Impairment

The Group has not recognized relevant impairment (ECL) on trade receivables, since there is no evidence of significant impairment of those assets.

The age of trade receivables and other receivables that were not impaired is as follows:

	ThUS$				
2020	Current	Due 31-90 days	Due 91-120 days	Non-current (*)	Total December 31, 2020
Trade and other receivables	7,692	1,874	999	11,742	**22,307**

	ThUS$				
2019	Current	Due 31-90 days	Due 91-120 days	Non-current (*)	Total December 31, 2019
Trade and other receivables	6,191	3,499	2,146	1,245	**13,081**

(*) Refer to Note 12. for further details on this balance.

c) **Liquidity risk**

Liquidity risk is the risk that the Group will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset.

Management supervises cash flow projections based on the Group's liquidity requirements to ensure there is enough cash, and also that unused credit lines are available, to cover its operational needs, without incurring unacceptable losses or risking damage to the Group's reputation. Such projections take into consideration debt amortization schedules and the compliance with the debt covenants.

As of December 31, 2020 and 2019, current financial liabilities held by ILAP Group have short-term maturities. The balances of current financial liabilities are detailed as follows:

In thousands of United States dollars (ThUS$)	2020	2019
Trade and other payables	10,288	11,805
Other current financial liabilities	16,404	13,983
Total	**26,692**	**25,788**

The balance of Other current financial liabilities consists mainly of current portion of loans payable. Refer to the Note 14 for further details.

The following are the remaining contractual maturities of loans and borrowings at the end of the reporting period, including estimated interest and excluding the impact of the arrangements for compensation payments:

	Contractual Cash Flows			
Non derivative financial liabilities	1-3 month ThUS$	3-12 month ThUS$	+1 years ThUS$	Total December 31, 2020
Interest	10,726	10,894	155,602	177,222
Capital of financial liabilities	5,816	7,457	393,703	406,976
Total	**16,542**	**18,351**	**549,305**	**584,198**

	Contractual Cash Flows			
Non derivative financial liabilities	1-3 month ThUS$	3-12 month ThUS$	+1 years ThUS$	Total December 31, 2019
Interest	11,008	11,225	177,222	199,455
Capital of financial liabilities	4,345	6,365	406,976	417,686
Total	**15,353**	**17,590**	**584,198**	**617,141**

d) **Market risk**

Senior Management is responsible for establishing the risk management policies of the Group, which aim to identify, analyse and mitigate the main risks faced by the business.

Below there is overview of the business´ main market risks and description of how they are managed.

e) **Currency risk**

The Company is exposed to currency risk as some of its transactions and the related balances of monetary assets and liabilities are denominated in a currency different from the U.S. dollar, which is the Company's functional currency. Those transactions are mainly denominated in Chilean pesos.

Management considers that currency risk is not significant due to the short collection and payment periods of the transactions involved.

In 2020, the Company recorded a net loss due to exchange differences of ThUS$ 82 and in 2019, the Company recorded net gain of ThUS$ 48. These results are presented under the heading "Exchange Differences" in the statement of comprehensive income.

The Group intends to naturally offset the currency risk exposure trying to maintain similar levels of assets and liabilities in the same currencies and similar maturity profiles. The Group does not currently use derivative instruments to hedge currency risk.

f) **Interest rate risk**

ILAP is not exposed to interest rate risk because its debt is at a fixed rate of 5.35% and deposits in banks have a very short maturity period.

g) **Power prices**

During 2020, the Company's commercial strategy was to minimize the risk of exposure to the spot market, given the changing market conditions, especially the consumption of the Distribution companies, with which the Group has long-term agreements. In summary, the above is reflected in obtaining new supply agreements for surplus energy of San Juan and Norvind. In particular, approximately 104 GWh-year were awarded during 2020 between Norvind and San Juan. These new agreements, together with the old ones, lead to a portion of less than 5% of the production to be sold to the spot market, thus minimizing the Company's risk and ensuring income for the next 4 years, focusing administrative efforts on optimizing the operation.

h) **Capital management**

The LAP Group's Board of Directors' policy is to maintain a sound capital base to preserve confidence from investors, creditors and the market, as well as supporting the business´ future development. The Company´s capital base is composed by equity contributions by shareholders and external debt financing obtained from multiple respected international and local financial institutions.

In terms of managing its capital structure, ILAP also works towards maximizing returns for its shareholders, by trying to continuously improve the terms of its funding (e.g. improving cost and tenor of its existing financings). As an example, the Group refinanced the debt of Norvind and San Juan projects in 2017.

In line with the industry practice, the ILAP Group uses ratio analyses to monitors its capital strength. One of this metrics is the leverage ratio, which is calculated by dividing net debt by total equity. Net debt corresponds to total indebtedness (including current and non-current debt) less cash and cash equivalents.

The ILAP Group does not have an established policy of maximum leverage. In practice, the maximum debt to total assets provided by external lenders for power generation assets is approximately 80%.

The debt-equity ratio of the Group at the end of the period is as follows:

ThUS$		
Debt-Equity	December 31, 2020	December 31, 2019
Total liabilities	475,304	485,650
Less: cash and cash equivalents	(7,363)	(18,428)
Less: time deposits	-	-
Net debt	**467,941**	**467,222**
Total Equity	(9,882)	2,907
Debt-equity ratio	**(47.35)**	**160.72**

i) **Classification of financial instruments by nature and type**

Assets

As of December 31, 2020 and 2019, the detail of financial assets (other than cash), classified by nature and type, is as follows:

2020 Types of Assets ThUS$	Debt instruments at amortized cost	Derivatives	Total
Trade and other current receivables	10,565	-	10,565
Related parties current receivables	3,836	-	3,836
Total current	**14,401**	**-**	**14,401**
Trade and other current receivables, non-current	11,742	-	11,742
Total non-current	**11,742**	**-**	**11,742**
Total	**26,143**	**-**	**26,143**

2019 Types of Assets ThUS$	Debt instruments at amortized cost	Derivatives	Total
Trade and other current receivables	11,836	-	11,836
Related parties current receivables	3,643	-	3,643
Total current	**15,479**	**-**	**15,479**
Trade and other current receivables, non-current	1,245	-	1,245
Total non-current	**1,245**	**-**	**1,245**
Total	**16,724**	**-**	**16,724**

Liabilities

As of December 31, 2020 and 2019, the detail of financial liabilities, classified by nature and type is as follows:

Types of Liabilities ThUS$ 2020	Loans and payables	Derivatives	Total
Other current financial liabilities	16,404	-	16,404
Trade and other payables	10,288	-	10,288
Current account payables related parties	4,902	-	4,902
Lease liabilities	362	-	362
Total current	**31,956**	**-**	**31,956**
Other non-current financial liabilities	378,811	-	378,811
Lease liabilities	11,652	-	11,652
Total non-current	**390,463**	**-**	**390,463**
Total	**422,419**	**-**	**422,419**

Types of Liabilities ThUS$ 2019	Loans and payables	Derivatives	Total
Other current financial liabilities	13,983	-	13,983
Trade and other payables	11,805	-	11,805
Current account payables related parties	4,724	-	4,724
Lease liabilities	343	-	343
Total current	**30,855**	**-**	**30,855**
Other non-current financial liabilities	389,933	-	389,933
Lease liabilities	12,014	-	12,014
Total non-current	**401,947**	**-**	**401,947**
Total	**432,802**	**-**	**432,802**

j) **Fair value**

Fair value hierarchy:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

The book values and fair values of financial assets and liabilities at the end of each year is as follows:

December 31, 2020	Carrying amount ThUS$	Fair value ThUS$	Fair value		
			Level 1 ThUS$	Level 2 ThUS$	Level 3 ThUS$
Other current and non-current financial liabilities	395,215	440,286	-	-	440,286
Total	**395,215**	**440,286**	**-**	**-**	**440,286**

December 31, 2019	Carrying amount ThUS$	Fair value ThUS$	Fair value		
			Level 1 ThUS$	Level 2 ThUS$	Level 3 ThUS$

Other current and non-current financial liabilities	403,916	423,470	-	-	423,470
Total	**403,916**	**423,470**	**-**	**-**	**423,470**

The recoverable amounts of PP&E and intangible assets determined in the impairment test have been calculated through the discount cash-flow models. This fair value calculation is classified as level 3 (see Note 8.c) for further details).

The Group has estimated that the carrying amounts of accounts payable and receivable of short-term nature are a reasonable approximation of their fair values.

12. Trade and other receivables

As of December 31, 2020 and 2019, the trade receivables and other receivables are composed as follows:

ThUS$	2020		2019	
	Current	Non-current	Current	Non-current
Trade receivables	9,219	11,742	10,857	1,245
VAT	152	-	-	-
Other receivables	1,194	-	979	-
Total	**10,565**	**11,742**	**11,836**	**1,245**

The Company recognized a balance of non-current trade receivables amounting to ThUS$ 11,742 as of December 31, 2020 and ThUS$ 1,245 as of 31 December 2019, following certain regulatory changes in Chile.

San Juan and Norvind are affected by the Law 21.185 issued on November 2, 2019 that created a transitional mechanism for stabilization of electricity prices for customers subject to regulation of rates. This law effectively "freezes" electricity prices that distribution companies ("DISCOs") bill to such customers starting from July 2019, with the referential (lower) prices at the level of rates as of June 2019. Those prices are referred to as stabilized consumer prices ("PEC" form its acronym in Spanish).

From 2021, the PEC will be adjusted by Chilean IPC ("adjusted PEC"). This adjustment will be applied until December 31, 2027, the maximum date at which the differences between the prices established in the original energy sale contracts between the generation companies (like San Juan and Norvind) and DISCOs and the PEC and adjusted PEC rates will be passed to the final customers.

During the stabilization period, that is, from July 1, 2019 to December 31, 2027, the CNE (National Commission of Energy), a Chilean regulator, will continue issuing decrees every 6 months that will include the PEC / adjusted PEC applicable to the next billing period, as well as the price that reflects the original conditions (price) of the contracts (sometimes referred to as the "node prices"), expressing the differences not collected by each contract, in the equivalent US$.

As a general rule, the differences to be collected that are generated from the application of the law will be interest-free. Exceptionally, the amounts not collected as of January 1, 2026 shall bear interest equal to six-month Libor, or the equivalent rate that replaces it, plus a spread corresponding to country risk at the date of application.

If the average node prices result in prices higher than the PEC or adjusted PEC, as appropriate, the prices will be adjusted downwards. Otherwise, prices will be increased, in order to recover previously unbilled amounts.

From July 2023 or until an amount of up to 1,350 million US dollars is accumulated in the entire PEC mechanism, the uncollected amounts cannot be increased, therefore, the CNE must adjust the PEC.

If during the period between 2025 and 2027, the CNE projects that the uncollected amounts cannot be fully recovered, it will determine the necessary adjustments to the PEC to fully extinguish the amounts before December 31, 2027.

The application of the law caused a greater lag between billing and collection of revenues for the whole generation industry in Chile with the corresponding financial and accounting impact that the situation entails.

ILAP estimated and recognized, as of December 31, 2020, the unbilled revenue for the PEC concept amounting to ThUS$ 11,742 (ThUS$ 1,245 as of December 31, 2019), determining that the financing component is immaterial. As per the PEC mechanism described above, the balance is expected to be collected in the period that exceed one year and in consequence is classified as non-current asset.

13. Trade and Other Payables

The breakdown of the balance is as follows:

ThUS$	December 31,	
	2020	2019
Invoices payable	10,054	11,450
VAT	234	355
Total	**10,288**	**11,805**

14. Other Financial Liabilities

The detail as of December 31, 2020 of this balance is as follows:

Issuer	Creditor	Nominal interest rate	Total	Current	Non-current
ILAP	The Bank of New York Mellon	5.35%	400,243	18,192	382,051
	Deferred Financing Expenses		(5,028)	(1,788)	(3,240)
			395,215	**16,404**	**378,811**

The summarized maturity dates of this instrument (based on its carrying amount) are as follows:

Period	2020 ThUS$
Within 1 year	16,404
Between 1 and 5 years	74,654
More than 5 years	304,157
Total	**395,215**

The detail as of December 31, 2019 of this balance is as follows:

Company	Creditor	Nominal interest rate	Total	Current	Non-current
ILAP	The Bank of New York Mellon	5.35%	410,750	15,789	394,961
	Deferred Financing Expenses		(6,834)	(1,806)	(5,028)
			403,916	**13,983**	**389,933**

The summarized maturity dates of this instrument (based on its carrying amount) are as follows:

Period	2019 ThUS$
Within 1 year	13,983
Between 1 and 5 years	65,150
More than 5 years	324,783
Total	**403,916**

Reconciliation of changes in financial liabilities to the cash flow statement:

Type of Liability	January 1, 2020	Cash Flows		Accrued interest	Amortization of deferred financing expenses	December 31, 2020
		Repayment	Interest paid			
Bonds	410,750	(10,367)	(21,572)	21,432	-	400,243
Deferred Financing Expenses	(6,834)	-	-	-	1,806	(5,208)
	403,916	**(10,367)**	**(21,572)**	**21,432**	**1,806**	**395,215**

Type of Liability	January 1, 2019	Cash Flows		Accrued interest	Amortization of deferred financing expenses	December 31, 2019
		Repayment	Interest paid			
Bonds	416,699	(5,871)	(21,954)	21,876	-	410,750
Deferred Financing Expenses	(8,653)	-	-	-	1,819	(6,834)
	408,046	**(5,871)**	**(21,954)**	**21,876**	**1,819**	**403,916**

Debt covenants are described below. The Company has complied with all the obligations under debt agreements as of December 31, 2020.

In September 2017, ILAP entered into a Note Purchase Agreement (NPA) with private investors for ThUS$ 412,000. The main obligations / restrictions for ILAP under the contract are as follows:

a) Compliance with Laws.
b) Maintain properties and businesses insurance against casualties and contingencies.
c) Own directly, not less than 99.99% of the Ownership Interest of each Guarantor free and clear of any Lien (other than Permitted Liens).
d) Each Obligor will preserve and keep its corporate, limited liability company.
e) Each Obligor will maintain proper books of record and account in conformity with IFRS and all applicable requirements of any Governmental Authority.
f) Each Obligor shall (i) observe and perform all obligations, covenants and agreements to be performed by it under, and comply with all conditions under, each Material Contract.
g) Delivery of Additional Material Contracts no later than thirty (30) days after the execution of any Additional Material Contract or any Replacement Material Contract.
h) Comply with all applicable Environmental Laws, except where such failure could not, individually or in the aggregate reasonably be expected to have a Material Adverse Effect.
i) The Borrower shall not make or permit any Investments, Subsidiaries, Partnership or Management Agreements.
j) None of the Obligors will engage in any business other than owning, operating and maintaining its Project(s).
k) None of the Obligors will incur, assume or permit to exist (upon the happening of a contingency or otherwise) any Lien on any of its property or assets, including the Collateral, except Permitted Liens.

l) No Obligor will (i) Transfer any Ownership Interest (or portion thereof) of any of its Subsidiaries (if any) or (ii) Transfer any of its properties or assets, other than, in the case of this clause (ii), Permitted Dispositions and any transaction permitted.
m) No Obligor will, at any time, directly or indirectly, declare, make or agree to pay, or incur any liability to declare or make or agree to pay, any Restricted Payment (including any related Capital Decrease) except if the Debt Service Coverage Ratio for the Company and the Guarantors (consolidated in accordance with IFRS) for (A) the period of the four consecutive historical fiscal quarters most recently then ended exceed 1.30 to 1.00, and (B) the period of the four consecutive prospective fiscal quarters then commencing with the Payment Date immediately preceding the date of such proposed Restricted Payment, exceeded 1.25 to 1.00,
n) No Obligor will, without the prior written consent of the Required Holders, (i) cancel, terminate, accept a surrender of or only with respect to a Material Contract that is an O&M Agreement, permit to expire, any Material Contract, unless such Material Contract is replaced with a Replacement Material Contract or (ii) amend, modify, supplement or assign any Material Contract if any such amendment, modification, supplement or assignment could reasonably be expected to result in a Material Adverse Effect.
o) No Obligor will enter into any Additional Material Contract, without the prior written consent of the Required Holders.
p) No Obligor will take any action that would cause such Obligor to be considered an "investment company" or a company controlled by an "investment company".
q) No Obligor will enter into any Swap Contract or engage in any similar transaction for speculative purposes.

The Company has complied with all the obligations as of December 31, 2020.

15. Related parties

a) Balances and transactions with related entities

Transactions with related parties are performed at market conditions.

At the reporting date, there are no warranties associated with related party balances or allowances for doubtful accounts.

Balances of accounts receivable as of December 31, 2020 and 2019 are as follows:

Accounts receivable from related companies - ThUS$	Relationship	Current	
		2020	2019
Latin America Power S.A.	Immediate parent	2	2
Empresa Eléctrica Carén S.A.	Under common control	3,834	3,641
Total Receivable		**3,836**	**3,643**

Balances of accounts payable as of December 31, 2020 and 2019 are as follows:

Accounts payable to related companies - ThUS$	Relationship	Current	
		2020	2019
Latin America Power S.A.	Immediate parent	1,748	1,570
LAP Holding B.V.	Ultimate parent	3,154	3,154
Total payable		**4,902**	**4,724**

b) Management and senior management

1. Management

Latin América Power S.A. is the Manager of the ILAP Group, who shall perform its duties through one of its representatives appointed by means of a private instrument or a public deed, with those powers expressly granted.

2. Remuneration and other compensations

The Manager does not receive any remuneration for its duties.

3. Expenses for Advisory to the Board of Directors

During the year ended on December 31, 2020, the Manager did not incur in advisory expenses.

4. Remuneration of Senior Management members who are not Directors

There is no senior management personnel since those duties are carried out by employees of the LAP Group to which the Company belongs.

5. Guarantees given by the Company in favor of its Manager

During the years ended on December 31, 2020 and 2019, the Company has not conducted this type of operations.

6. Guarantee clauses: Manager and Management of the Company

The Company has not agreed any guarantee clauses with its Manager.

16. Provisions

Changes in the balance of the decommissioning provision during the years ended December 31, 2020 and 2019, were as follows:

2020 In thousands of US dollars (ThUS$)	Decommissioning costs provision
At January 1, 2020	51,615
Unwinding of discount	1,330
Other	(60)
At December 31, 2020	**52,885**

2019 In thousands of US dollars (ThUS$)	Decommissioning costs provision
At January 1, 2019	50,258
Unwinding of discount	1,296
Other	61
At December 31, 2019	**51,615**

17. Income taxes regime background

The current income tax is accounted for based on the taxable income determined for tax purposes. The recognition of deferred tax in respect of temporary differences and other events that generate differences between the taxable base of assets and liabilities and its accounting base is performed in conformity with IAS 12.

As of December 31, 2020 and 2019, the Company has not recorded any taxable profits for its operations, as it has accumulated tax losses.

The corporate income tax rate applicable to the Company and its subsidiaries in 2020 and 2019 is 27%.

18. Income tax assets and liabilities

a) Deferred taxes

The movement of deferred taxes is presented below:

2020 ThUS$	Beginning balance	Recognized in profit or loss	Ending balance
Tax losses	33,356	(580)	32,776
Property, plant and equipment and intangibles	3,779	471	4,250
Other	(2,219)	1,291	(928)
Net deferred tax assets (liabilities)	**34,916**	**1,182**	**36,098**

2019 ThUS$	Beginning balance	Recognized in profit or loss	Ending balance
Tax losses	32,713	643	33,356
Property, plant and equipment and intangibles	2,838	941	3,779
Other	(1,947)	(272)	(2,219)
Net deferred tax assets (liabilities)	**33,604**	**1,312**	**34,916**

Those balances are reflected in the statements of financial position as of December 31, 2020 and 2019, as follows:

ThUS$	2020	2019
Assets	36,098	36,149
Liabilities	-	(1,233)
Net deferred tax assets (liabilities)	**36,098**	**34,916**

The recovery of those deferred tax asset balances depends on obtaining sufficient tax earnings in the future. The ILAP Group believes its future taxable profits projections provide convincing evidence to assert that those assets are recoverable. The Company also considers tax planning opportunities that the Company would take in order to create or increase taxable income in a particular period before the expiry of a tax loss or tax credit carryforward. It is worth mentioning that in the case of Chile tax losses do not expire according to the local law.

In 2020 and 2019, the Company decided to derecognize a portion of the deferred tax assets related to tax losses of ILAP that were not considered recoverable.

b) Amounts recognized in profit or loss:

	ThUS$		
Current tax expense	2020	2019	2018
Current tax year	-	-	(1)
Deferred tax benefit (expense)			
Origination and reversal of temporary differences	1,182	1,312	5,516
Tax (expense) / benefit from continuing operations	**1,182**	**1,312**	**5,515**

c) Effective tax rate reconciliation

The table below shows a reconciliation of the effective tax rate for the years ended December 31, 2020, 2019 and 2018:

ThUS$	2020		2019		2018	
	Amount	Rate	Amount	Rate	Amount	Rate
Loss before taxes	(10,771)		(20,442)		(20,419)	
Income tax benefit at statutory rate (27%)	2,908	27.0%	5,519	27.0%	5,513	27.0%
Derecognition of deferred tax assets	(1,726)	(16.0%)	(2,988)	(14.6%)	-	-
Non-taxable / non-deductible items and other differences	-	-	(1,219)	(6.0%)	2	-%
Income tax (expense) benefit at effective rate	**1,182**	11.0%	**1,312**	6.4%	**5,515**	27.0%

19. Equity

Capital subscribed and paid

Inversiones Latin América Power Limitada is controlled by Latin América Power S.A. according to the following shareholding composition:

Company	Capital Paid USD $
LAP Chile S.A.	89,800,779
LAP Holding B.V.	8
Total	89,800,787

20. Revenue

The composition of revenue for the years 2020, 2019 and 2018 is as follows:

ThUS$	December 31		
	2020	2019	2018
Energy sales	59,784	51,535	40,670
Capacity sales	12,765	10,956	10,285

Other revenue	338	25	45
Intercompany revenue	-	-	1,097
Total	**72,887**	**62,516**	**52,097**

The following tables show revenues from customers with a participation higher than 10% in the total Group's sales during the years 2020, 2019 and 2018:

Revenue from external customers (ThUS$)	2020	%
Enel Distribución Chile S.A.	17,904	24%
Total 2020	**17,904**	

Revenue from external customers (ThUS$)	2019	%
Empresa de Transporte de Pasajeros Metro S.A.	17,418	28%
Total 2019	**17,418**	

Revenue from external customers (ThUS$)	2018	%
Compañía General de Electricidad S.A.	13,850	27%
Total 2018	**13,850**	

21. Cost of Sales

The composition of cost of sales for the years 2020, 2019 and 2018 is as follows:

ThUS$	December 31		
	2020	2019	2018
Operating, management and servicing costs	20,317	13,746	9,835
Maintenance	5,364	4,651	4,676
Municipal tax	33	68	224
Corporate social responsibility expenses	62	88	84
Transmission costs	6,712	6,874	5,463
Insurance	944	907	857
Others	765	1,172	1,057
Depreciation and amortization for the year	21,280	23,034	22,448
Total	**55,477**	**50,540**	**44,644**

22. Administrative expenses

The composition for the years 2020, 2019 and 2018 is as follows:

ThUS$	ThUS$		
	2020	2019	2018
Depreciation and amortization for the year	103	104	106
Services provided by third parties	1,794	1,268	1,391
Additional taxes	930	915	919
Travel expenses	9	-	-

Total	**2,836**	**2,287**	**2,416**

23. Finance expenses

The composition for the years 2020, 2019 and 2018 is as follows:

ThUS$	ThUS$		
	2020	2019	2018
Interests on debts and borrowings	23,238	23,695	24,096
Other financial costs	49	59	144
Unwinding of discount on the decommissioning provision	1,330	1,297	1,264
Interests on lease liabilities	662	679	-
Total	**25,279**	**25,730**	**25,504**

24. Impairment charges

The composition for the years 2020, 2019 and 2018 is as follows:

ThUS$	ThUS$		
	2020	2019	2018
Impairment of Norvind goodwill (Note 8 b)-c))	-	4,665	-
Total	**-**	**4,665**	**-**

25. Contingencies, Guarantees and Commitments

a) Contingencies

On April 30, 2015, the Chilean Internal Revenue Service ("SII") formally requested Norvind to provide the relevant supporting documentation regarding tax-losses declared in its annual income tax declaration (Form 22) corresponding to Tax Year 2012 (Commercial Year 2011). After reviewing the documentation presented by Norvind, the SII issued the Resolution number 195 ruling that the documentation submitted was not sufficient to support expenses and carryforward losses declared, for a total amount of ThUS$ 12,229. Thus, additional corporate income taxes and fines were determined for Tax Year 2012 for an amount of ThUS$ 2,631.

On September 21, 2015, Norvind submitted an administrative appeal ("RAV") before the SII adding new supporting documentation and accounting records. After the rejection of the RAV, and having exhausted all administrative remedies available, on December 17, 2015 Norvind requested the Judicial Review of the Resolution number 195 before the Tax Courts. In parallel, Norvind held conversations with the SII in order to explore resolution of the matter. Those negotiations resulted in a settlement executed on June 9, 2020, by which the SII recognized and set Norvind's tax-loss position (carryforward losses) for ThUS$ 4,243 per the Tax Year 2012; hence, Norvind shall pay no additional corporate tax nor fines regarding the Tax Year 2012.

On April 30, 2019, the SII issued the Resolution number 1109 whereby Norvind's tax losses declared in Tax Year 2016 (Commercial Year 2015) were reduced from ThUS$ 25,411 to ThUS$ 3,382. Such reduction consisted in the subtraction of the losses and expenses questioned in the Resolution number 195 (which at the time was being disputed before the Tax Courts, as described in the preceding paragraph), plus other expenses generated in subsequent years, under the argument that Norvind was not allowed to recognize expenses and carryforward losses determined under criteria already rejected through the Resolution 195.

On June 13, 2019, Norvind submitted a RAV requesting the validation of its tax-loss position. The RAV was denied. As a result, a Judicial Review was filed before the Tax Court and this procedure is still pending.

Based on the evaluation of criteria in IFRIC 23 *Uncertainty over Income Tax Treatment* the Group concluded that it is probable that its tax treatments related to the Norvind's expenses and tax losses challenged by the SII in the Resolution 1109 will be ultimately accepted by the taxation authorities.

b) Commitments

Commercially, ILAP has a policy of committing annual energy volumes through intermediate PPAs. As of December 31, 2020, the following energy sales commitments have been made:

Power Plant (subsidiary)	Volume sale commitment (MWh/year)
San Juan	439,813
Norvind	95,184
Total	**534,997**

26. COVID-19

The effects of the COVID-19 pandemic have affected all economies around the world, and Chile where the ILAP Group carries out its operating activities is no exception. Mobility restrictions and social distance measures such as curfews and quarantines have been imposed by authorities in both countries to contain the spread of the disease, thus affecting the normal course of business. Given the LAP's industry nature is essential utility, special permits were assigned by authorities to ensure the mobility of the LAP's power plants' workers under strict safety measures to avoid potential shutdowns or production curtailments allowing ILAP power plants to keep up and running during the whole year 2020. However, in Chile the Company's revenues were somehow affected by a lower demand of energy from regulated costumers which implies lower demand from electricity distribution companies (DiscCos) under the PPA contracts, forcing San Juan and Norvind to sell the energy surpluses to the spot market at lower prices.

In the short term, lower energy demand from Chilean DisCo continues to be a concern, however the successful COVID-19 vaccination process which is being executed by Chile, leading worldwide doses administered per 100 habitants, helps to mitigate the uncertainty around the recovery of the economic activity and therefore the energy demand.

27. Subsequent events

Between December 31, 2020 and the date of issuance of these consolidated financial statements, the Directors of the Company are not aware of any subsequent events that may significantly affect the interpretation of these consolidated financial statements.

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APPENDIX A INDEPENDENT ENGINEER REPORT

ILAP Onshore Wind Farms Refinancing
Technical & Environmental Due Diligence Report

Final Report

June 2021

ARUP

Private and confidential

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June 1, 2021

ILAP Onshore Wind Farms Refinancing - Technical & Environmental Due Diligence

In accordance with the terms of reference set out in our engagement letter dated May 14, 2021, (the “Engagement Letter”) we enclose our Final Technical & Environmental Due Diligence Report (the “Report”) in connection with the financing of the ILAP onshore wind farms in Chile (the “Project”),

The basis of preparation of our work to date is attached to this report. Those terms of reference comprise the agreed scope of our work to date, directed at those issues which you determined to be critical to the transaction. You should note that our findings do not constitute recommendations to you as to whether or not you should proceed with the proposed transaction.

This document is private and confidential and is intended only for the information of the addressee. It may not be copied or distributed without our prior written consent.

The information contained in this the document is supplied to the addressee only on the condition that Arup and any employee of Arup are not liable for any error, or inaccuracy contained therein, whether negligently caused or otherwise, or for any loss or damage suffered by any person due to such error, omission, or inaccuracy, as a result of such supply.

This report is addressed to you in accordance with the terms of the Engagement Letter.

Yours faithfully

Jonathan Yates
Project Director

Important notice and Disclaimer

This report was prepared by Arup Latin America S.A. (“Arup”) for the benefit of Inversiones Latin American Power Limitada (‘ILAP’) solely in its capacity as Technical Advisor pursuant to an Agreement dated May 14, 2021. This report may be provided to third parties solely to inform any such person that Arup’s report has been prepared and to make them aware of its substance but not for the purposes of reliance. No third party is entitled to rely on this report unless and until they and Arup sign a reliance letter in the form attached to our appointment.

Arup does not in any circumstances accept any responsibility or liability to Retail Investors whether via bond issue or otherwise and no such party is entitled to rely on this report (or document).

In preparing this report (or document) Arup has relied on information provided by others and Arup does not accept responsibility for the accuracy of such information. Arup emphasizes that the forward-looking projections, forecasts, or estimates are based upon interpretations or assessments of available information at the time of writing. The realization of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. Actual events frequently do not occur as expected, and the differences may be material. For this reason, Arup accepts no responsibility for the realization of any projection, forecast, opinion or estimate.

Findings are time-sensitive and relevant only to current conditions at the time of writing. Arup will not be under any obligation to update the report to address changes in facts or circumstances that occur after the date of our report that might materially affect the contents of the report or any of the conclusions set forth therein.

No person other than our Client and any party to whom reliance has been expressly permitted by us pursuant to a reliance letter may copy (in whole or in part) or rely on the contents of this Report without our prior written permission. Any copying or use of this report (in whole or in part) whatsoever shall be accompanied by or incorporate this notice at all times.

Arup Project No. 282155-00

For further information regarding this Report, please contact:

Jonathan Yates, (jonathan.yates@arup.com)
Jorge Macedo, (jorge.macedo@arup.com)

Glossary of terms

BNEF	Bloomberg New Energy Finance Ltd.
BoP	Balance of Plant
CL	Cabo Leones
CNE	Comision Nacional de Energia
COD	Commercial Operations Date
COG	Communication and Operations Group
DIA	Declaracion de Impacto Ambiental
DisCo	Distribution Company
EHS	Environment, Health, and Safety
EPC	Engineering Procurement and Construction
EUR	European Euro
FM	Financial Model
G&A	General and Administrative expenses
GDP	Gross Domestic Product
H&S	Health and Safety
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IFC	International Finance Corporation
ILAP	Inversiones Latin American Power
IMS	Integrated Management System
ISO	International Organization for Standardization
KPI	Key Performance Indicator
LAP	Latin American Power
MoE	Ministry of Energy
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OHL	Overhead Line
OpEx	Operating Expenditures
OSHA	Occupational Safety and Health Administration
PCYA	Post Construction Yield Analysis
PPA	Power Purchase Agreement
SAA	Service and Availability Agreement
SCADA	Supervisory Control and Data Acquisition
SEN	Chile's National Electric System
SIC	Sistema Interconectado Central
SING	Sistema Interconectado Central del Norte Grande
SJS	San Juan Substation
SJU	San Juan
SMA	Service Management Agreement
SPV	Special Purpose Vehicle
TOT	Totoral
USD	United States Dollar
VDR	Virtual Data Room
WTG	Wind Turbine Generator

Basis of Preparation

Basis of preparation

- This Report has been prepared in accordance with the scope of work outlined in our Letter of Engagement dated May 14, 2021 and constitutes a review of technical documentation with the intention of identifying major risks in the design, construction and operation of the project.
- This report is private and confidential and is intended only for the information of the Client. It may not be copied, distributed or relied upon without our prior written consent.
- The basis of preparation of our work to date is described in this section. Those terms of reference comprise the agreed scope of our work to date, directed at those issues which the client determined to be critical to the financing. You should note that our findings do not constitute recommendations to you as to whether or not you should proceed with the proposed transaction.
- Our work has been based on a desktop review of the information available in the virtual data room and multiple conference calls with ILAP's management and technical teams between March 30 and May 28, 2021.
- We have satisfied ourselves, so far as possible, that the information presented in our report is consistent with the information which was made available to us in the course of our work.
- Our analysis was based on our technical knowledge. Arup's views presented in this report reflect our best assessment of the data provided.
- In this report, Arup provides an overview of the asset from a technical perspective, and a high-level analysis of the operational and capital expenditure projections.

Limitations of scope

- Arup notes that the opinions reflected in this report are not operational recommendations and correspond exclusively to our technical views based on the information made available for review.
- Arup's future yield assessment does not consider climate change effects on wind patterns or resource availability.

Sources of information

- We have reviewed Management's proprietary information made available in the data room and we have identified the documents most relevant to our review.
- This report comments on the Financial model dated May 31, 2021 ('2021.05.31 – ILAP Model (P50) HARCODED AMORT).xlsx').

Report Contents

1. Executive Summary: Key Findings

- Inversiones Latin America Power (ILAP, the Company) are the owner of two wind farms, which are located in central Chile. San Juan (193.2MW) began operations in March 2017 and Totoral (46.0MW) began operation in January 2010. San Juan was developed and constructed by LAP, while Totoral was acquired by the company in January 2013.
- Both projects use Vestas technology, who have been retained to provide a full-service O&M contract for all aspects of the turbine, including the tower and blades. The Balance of Plant and civil infrastructure is maintained by LAP through service agreements with its subsidiary, ILAP.
- The projects revenues are derived from long-term power purchase agreements (PPAs) with local Chilean Distribution Companies (DisCos) and medium-term contracts with various private and quasi-sovereign parties. The contracts currently in place, expire in 2033.
- The projects have benefited from high levels of availability and production compared to LAP budget expectations and performance has improved as the Company worked through minor ramp-up equipment issues, as would be expected in the early stages of these projects. Vestas contractually guarantees availability of the turbines at 97% for both sites. In 2021, this availability requirement will increase to 98% for San Juan. These levels of availability have consistently been achieved.
- The Projects have both encountered some losses, including grid curtailment, which would be expected in the early part of operations. Importantly, a new transmission line (Cardones-Polpaico 500 kV) was completed in 2019 and has reduced the level grid curtailment in 2020. Arup notes that no formal log of curtailment is provided from the grid. However, Arup recommends that LAP improve their method for quantifying and logging outages, which will help to isolate issues within the facility from true grid curtailment. Other minor breakdowns are considered by Arup to be isolated events, which management has rectified.
- Arup has undertaken an independent yield assessment for the two projects, using industry-standard approaches. For Totoral, historical operating information from the period 2017-2020 was used to develop a post-construction yield assessment. Our analysis indicates an average Net Yield of 81.4 GWh/ year (P50) and a 1-year P90 of 70.7 GWh.
- For San Juan, there has been a complicated ramp-up period: as new windfarms have been constructed between 2017 and 2020. Whilst our post-construction yield assessment takes these effects into account, the 'clean' operating period is relatively short. Arup considers there remain some uncertainties in the post-construction approach and so a blended pre-construction and post construction yield assessment has been used.
- Our analysis indicates an average Net Yield of 552.1 GWh/ year (P50) and a 1-year P90 of 478.6 GWh. These values take into consideration the likely wake-losses from nearby development, Cabo Leones III, which began operation in December 2020, Sarco (2018), and Cabo Leones I (2020).
- LAP has an appropriate O&M/asset management approach, with an in-house staff covering both wind farms and some central resources to support other LAP projects in the region. LAP benefits from a cloud-based maintenance management system and remote monitoring of the assets via SCADA to a control room situated in Santiago, Chile.
- There are opportunities for improvement to LAP's overall O&M approach, which LAP has indicated they intend to take, including better monitoring of production losses to help improve performance as well as a more robust inspection program, particularly for towers and foundations.
- Based on the information provided, the operating assets of the two projects appear to be operating satisfactorily and are well-maintained. For the wind turbines and towers, the Vestas O&M contract provides a high-quality service to monitor and maintain this equipment. There have been a few, minor operating defects since start of operations, which Vestas have resolved.
- The San Juan project suffered from a zig-zag transformer failure in July 2020, causing a partial outage for 36 days. This has been investigated and appeared to arise from combination of technical and operating factors. Measures are in place to ensure this issue be mitigated in future.
- The foundations for the wind farm are a key component in the overall project and the expected useful life of the asset. Should any problems arise during the operational phase, these can often be uneconomic to repair. The validation of an appropriate design and verification of construction quality are important to ensure that a useful life of more than 20 years for the foundations can be expected. Although no fundamental flaws have been identified with the design, a high-level review has shown that the fatigue analysis in the design phase was limited. Arup therefore recommends that LAP should undertake a fatigue analysis, which LAP management has indicated they intend to undertake. Arup recommends a downside sensitivity case to consider a 2% production curtailment from year 15 onwards to ensure that fatigue loads remain within the design-envelope of the foundations.
- Arup understands that LAP is discussing life-extension with Vestas for the tower and wind turbine generators once the existing contracts expire (Totoral, March 2029; San Juan, March 2037). This is a reasonable strategy. Considering the appropriate maintenance strategy in the meantime, Arup believes that from a commercial point of view, sufficient budget has been built in the financial model for the wind farms to operate for 30 years.

Report Contents

2. Business Overview

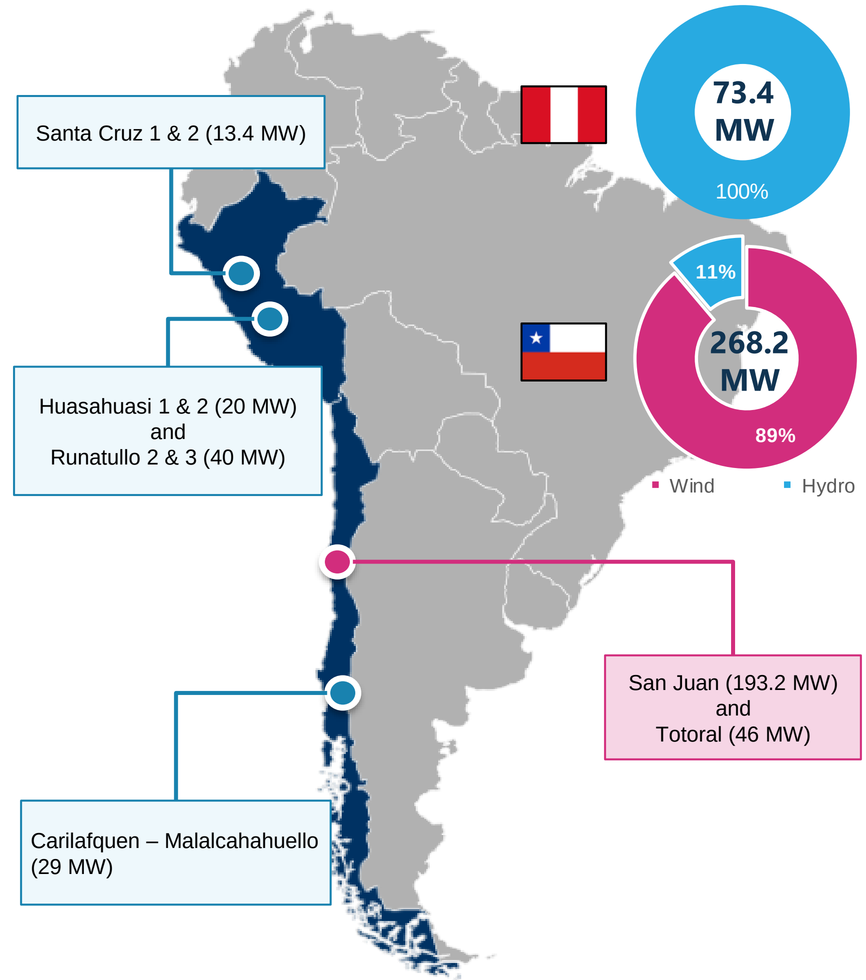
Latin America Power ("LAP") is a company focused on the development of renewable power generation in Latin American countries. It is owned by BTG Pactual, PátriaInvestimentos and GMREnergy.

Latin American Power

- Latin America Power Limitada (LAP) is looking to refinance two of its existing wind parks in the Atacama region of Chile: Totoral and San Juan.
- LAP is responsible for the development of multiple renewable power projects throughout Latin America. The Company's primary shareholders are BTG Pactual (45.85%), Patria Investimentos (45.85%), and GMREnergy (8.29%). The Company was founded in September 2011 as a renewable power developer - seeking to provide investments that improve the energy matrix in Chile and Peru.
  - **BTG Pactual**: Headquartered in Brazil and founded in 1983, they are a financial investment firm with experience in the Latin American renewable markets. BTG maintains over US$ 75 billion under management. They have presence on four continents: South America (Brazil, Colombia, Peru and Chile), North America (United States), Europe (UK) and Asia (China).
  - **Patria Investimentos**: In business for over 28 years, Patria is a leading alternative asset management company in Latin America. They maintain a diversified infrastructure portfolio including multiple renewable platforms, as well as telecom and logistics portfolio funds.
  - **GMR Holding**: This Group actively participates in the energy, forestry, construction and real estate sectors. GMR Energy is the subsidiary through which the group participates in the electricity market
- LAP operates 342 MW of installed capacity: six hydroelectric plants in Peru (73.4 MW), two hydro plants in Chile (29 MW), as well as Totoral (46 MW) and San Juan (193.2 MW).
- LAP fully owns Inversiones LAP Limitada (ILAP), which in turn owns 100% of Norvind S.A. (Totoral) and San Juan S.A. (San Juan), two special purpose vehicles which have responsibility to operate and maintain the Totoral and San Juan parks. The corporate organizational structure is presented in Appendix D.
- LAP began operations of Totoral in January 2010 and San Juan in March 2017. After successful start-up and historical operation of its facilities, the Company is looking to refinance the outstanding debt of these two assets. This Report provides a technical review of the assets, its historical performance, and a future view of the anticipated production based on the technical characteristics and resources assessments.

Figure 2.1. Map of LAP Operational Assets

Source: LAP



2. Business Overview – Windfarms Summary

LAP operates two windfarms within its portfolio. Totoral, a 46MW windfarm, began operations in January 2010. San Juan – a 193MW windfarm, began operations in March 2017.

- LAP operates two windfarms within its energy generation portfolio: Totoral and San Juan (the "Assets"). Each wind farm operates as a special purpose vehicle (SPV) owned by LAP through its fully owned subsidiary ILAP. Both assets are connected to the Chilean National Electric System (SEN). Both projects benefit from long-term O&M agreements with the Original Equipment Manufacturer (OEM) - Vestas, who themselves have an excellent history of supporting wind turbine manufacture, installation and operations across the world.
- The Totoral project benefits from over 10 years of operation with consistently positive performance against contractual requirements.
- The San Juan Project became operational in March 2017. The asset has broadly performed above contractual requirements. Three new neighboring plants have become operational since COD: Sarco, to the northeast the San Juan project and Cabo Leones I and Cabo Leones III, both to the south of the plant. Arup understands that an extension to Cabo Leones is in construction phase, which is due to commence operation during the next 12 months, according to reports from the developers, and which has been accounted for in the yield assessment.

Parameter	Totoral	San Juan
Project Company	Norvind S.A.	San Juan S.A.
Location	IV Region of Coquimbo, 290 km north of Santiago, Chile	III Region of Atacama, in the southern coastal area of the province of Vallenar, Chile
Installed power	46.0M W	193.2 MW
Turbines	23 x Vestas V90-2.0 MW	56 x Vestas V117-3.3 MW
Turbine height/ diameter	80.0m height / 90.0m rotor diameter	91.5m height/ 117.0m rotor diameter
Power system	National Electric System (SEN)	National Electric System (SEN)
Node	Las Palmas	Punta Colorada
Electrical interconnection	Medium voltage cables connect the wind turbines to the 23/66 kV substation located within the project boundary. A 7-km transmission line links the 23/66 kV substation to the SEN interconnection point.	The project has a 33/220 kV substation within the area and a 83.6km transmission line connecting with the existing Punta Colorada substation. Interconnection agreement is with Transelec.
Commercial Operations Date	Full Commercial Operation Date (COD) in January 2010	Full Commercial Operation Date in March 2017
Current performance	Since 2017, average annual sold generation was 80.1 GWh/yr; average total plant availability is 96.8% and average turbine availability is 98.3%.	From COD, average annual sold generation was 551.7 GWh/yr; average total plant availability is 96.3% and average turbine availability is 98.6%.

2. Business Overview – Key Project Participants

The Totoral and San Juan projects operate in Chile's diverse market. The projects are backed by long-term off takes and Vestas, a top turbine manufacturer, provides O&M services to both assets.

Overview

- LAP operates the Totoral and San Juan windfarms in Chile's diverse and mature energy market, which aims to be 70% renewable by 2050.
- LAP leverages its operating experience across the energy sector and takes a hands-on approach to managing its assets.
- In addition to LAP, key participants in LAP's business model are outlined in Figure 2.2. A brief description of each is provided below:

Vestas

- Vestas is a Danish manufacturer, seller, installer, and service provider of wind turbines. The Company was founded in 1945 and has a proven track record for delivering best-in-class wind turbines since 1979.
- As of 2019, Vestas has installed more over 66,000 turbines in over 80 countries, which account for more than 100 GW of installed wind power.
- In Chile, Vestas has a strong local track record: as of 2021, the company has supplied 443 turbines for projects in Chile, with a generating capacity of over 1.0 GW.

Transelec

- Transelec is the main electricity transmission company in Chile; it transports electricity to 98% of the population through its transmission lines that stretch for over 10,000km from North to South, with nearly sixty 500kV and 220kV substations.

Comisión Nacional de Energía (CNE)

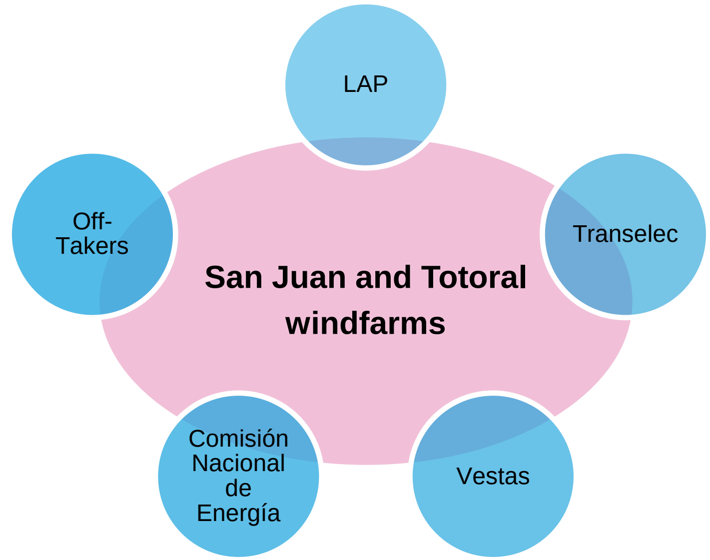
- CNE is the main state organization in charge of regulating the electricity sector. It designs and coordinates plans, policies and regulations for the function and development of the Chilean electricity grid.
- CNE analyses prices, tariffs, and technical standards to which companies must adhere.

Off-takers

- The Assets benefit from long-term power purchase agreements (PPAs) with 23 Chilean Distribution Companies as well as medium-term contracts with private parties.

Figure 2.2. Operating Environment and Key Project Participants

Source: Arup Analysis



2. Business Overview - Key Project Participants

Vestas has a total installed capacity of 122GW and has ranked 1st on BNEF's list of OEMs for several years in a row, making the company a Tier 1 supplier.

Vestas key facts and figures

- Vestas has installed wind turbine generators (WTGs) in 83 countries and is the only global energy company that is exclusively dedicated to wind energy. The company has over 40 years experience in engineering, transportation, construction, and operations and maintenance in the wind turbine industry. Total installed capacity worldwide is more than 132 GW.
- The company was ranked first in 2019 on the list of global onshore WTG Original Equipment Manufacturers (OEMs), according to commissioned capacity, by BloombergNEF (BNEF).
- Vestas has a strong global presence in terms of offices, production and assembly facilities around the world. Blade, nacelle, tower, control systems, and sales and service facilities are spread across 65 countries.
- The company has more than 25,000 employees as of 2020.

History

- Vestas began serial production of WTGs in 1980 and erected the first eighty 55 kW models.
- At the end of 1985 Vestas had sold 2,500 WTGs to the US market. The company also pioneered the first pitch-regulated WTGs.
- In 1995 the first Vestas WTG with a capacity of over a megawatt (the V63) was installed in Denmark. In 1997, the V47-660 kW and the V66-1.65 MW models were introduced.
- During 2002, the first 3 MW V90 prototype WTG was built in Germany. There are currently c. 3,400 (10.2 GW in total capacity) 3 MW V90 turbines installed around the world, and c. 1,700 (5.8 GW in total capacity) 3.3MW/3.45MW V117 turbines. The designs are well proven and implemented around the world.

Market Share

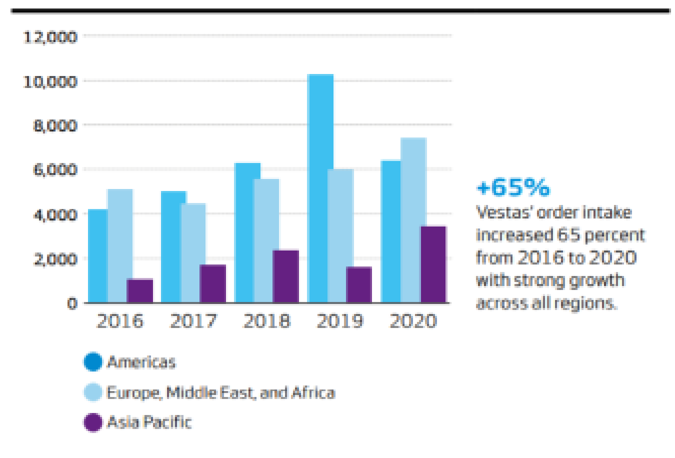
- Vestas market share in 2019 was 18% of the total installed onshore windfarms that year. In 2020, Vestas is reporting more than 17 GW delivered to customers, an increase of 34% from 2019.

Figure 2.3. Vestas global footprint

Source: Vestas annual report 2019

Figure 2.4. Vestas order intake (MW)

Source: Vestas annual report 2020



2. Business Overview – Chilean Energy Market

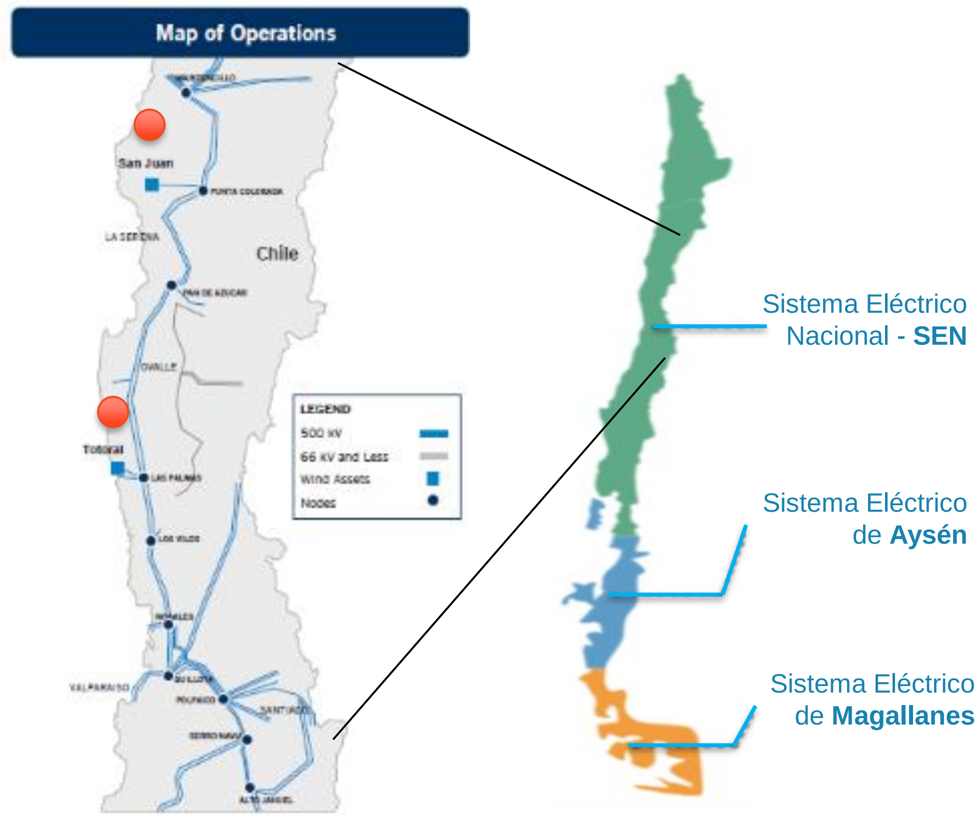
San Juan and Totoral windfarms are located in a key region within Chile's power market due to its close proximity to densely populated areas such as Santiago.

Chile Energy Market

- According to the International Energy Agency (IEA), the Chilean electricity generation market is currently dominated by thermoelectric (coal) generation (33%), followed by hydroelectric (26%) and natural gas generation (19%).
- According to the most recent publicly available data from the IEA, in 2019 Chile had 81.2 GW of installed electricity generation capacity (up from 75.4 GWh in 2015). Generation from renewable energy sources increased 11.2% from 2015-2019, with 36.5 GWh of total generation (45%). Its main sources were hydro (20.8 GWh), solar PV (6.3 GWh), wind (4.8 GWh) and biofuels (4.4 GWh). Wind and solar generation have seen the most growth in the past five years, with wind more than doubling in generation and solar increasing by 4x over this period.
- Energy demand in Chile is closely correlated with GDP since industrial activity accounts for approximately 60% of electricity consumption.
- Chile is a geographically narrow country from north to south. This creates challenges for the transmission network in transmitting power across large distances from sources of generation, to demand centres such as major cities. As such, new transmission legislation has been designed to foster network development, which directly benefits renewables which are often located in remote locations.
- The power grid in Chile is divided into three distinct power systems:
  - Sistema Eléctrico Nacional (SEN)
  - Sistema Eléctrico de Aysén.
  - Sistema Eléctrico de Magallanes.
- The SEN was previously divided into Sistema Interconectado Central (SIC) and Sistema Interconectado Central del Norte Grande (SING). These two systems were officially merged and integrated via the new Cardones-Polpaico 500 kV transmission line, which came online in March 2019.
- San Juan and Totoral windfarms are located in the SEN, and within close proximity to densely populated areas such as Santiago and account for an approximate combined generation capacity of 239.2 MW.

Figure 2.5. Overview of the Chilean electricity system

Source: Ministerio de Energía, Chile



The San Juan and Totoral windfarms are located in a key region within Chile's power market due to its close proximity to densely populated areas such as Santiago, the capital of the country.

Chile Energy Market (Cont.)

- Electricity demand in Chile has consistently grown at more than 4% per year since 2000 and is projected to continue growing with an anticipated doubling of both generation and consumption by 2050. The majority of this growth is expected to occur in the SEN system, owing to the large urban centres.
- After the 1982 Electricity Law, Chile became one of the first countries to introduce a liberalized electricity market which has undergone several regulatory changes since, including the introduction of the spot power market with marginal pricing that offers unique access to generators and opened the power sector to private investment.
- Chile introduced an ambitious National Energy Policy 2015, which was amended in 2019 when the original goals were already being surpassed. The amendments a roadmap to carbon neutrality by 2050, including 70% renewable penetration by 2030 and phasing out coal-powered electricity production by 2040.
- Chile has supported renewable growth by introducing policies, such as the 2016 Energy Law amendment and an innovative, technology neutral auction design, which lead to the increase of bidder participation and reduction of energy prices.
- Additionally, domestic electrical grid interconnections are actively pursued to support the integration of renewables. The development of the Cardones-Polpaico 500 kV transmission line in 2019 has enabled the renewable sources generated throughout northern Chile to be efficiently delivered to demand centres, such as Santiago.
- This new grid connection project had a positive impact on the performance of the San Juan and Totoral projects, owing to a more reliable grid since 2019 and reducing curtailment losses in recent years.

Figure 2.6. Chilean Power Map of Operations

Source: CNE Report, 2017, 2018

2. Business Overview – Power Purchase Agreements

Totoral and San Juan benefit from long-term PPA offtake agreements with Chilean Distribution Companies (DisCos), providing cash flow stability throughout the duration of the contracts.

Off-takers

- The Assets benefit from long-term PPA offtake agreements with 23 Chilean Distribution Companies (DisCos), providing cash flow stability throughout the duration of the contracts.
- The PPAs provide the Assets with cash flow stability due to the risk distribution amongst several independent regulated and non-regulated entities.
- Totoral has a diversified set of off-takers. Currently it has 38 PPAs with DisCos and Non-regulated clients. Non-regulated PPAs represent roughly 75% of the total contracted generation. 40 GWh/year of generation (just under half of contracted generation to non-regulated off-takers) is represented by its contract with Minera Cerro Negro.
- For San Juan, the majority of off-takers are DisCos, representing amost 60% of contracted generation in 2021. Aside from DisCos, San Juan only holds one non-regulated PPA with Enel for 180 GWh of generation in 2021-2023, and one PPA agreement with the Metro, which ends in 2033.

PPA Key Terms

- Capacity charges are passed through to the off-takers based on their usage during the 52 hours of highest annual demand by the Sistema Eléctrico Nacional, and then re-balanced based on a determination by the Coordinator Eléctrico Nacional (the Coordinator, or CEN).
- Payment is made in Chilean Pesos but pegged to the dollar using the exchange rate published by the Central Bank of Chile.
- Transmission costs incurred by the seller are passed through to the buyer.

Table 2.1. Overview of PPA Agreements

Source: Arup analysis of LAP information.

Client Type	Total PPAs	Contract End Year	Contracted Generation for 2021 (GWh)	PPA Awarded Prices (USD/MWh)
TOTORAL	**38**		**179.4**	
DisCos (with 23 DisCos)	23	2033	45.5	113.22
Non-Regulated	15	2022-2026	133.9	40.00 – 70.00
SAN JUAN	**70**		**641.3**	
DisCos (with 23 DisCos)	67	2033	381.5	100.65-103.22
Metro	1	2033	59.8	95.00
Non-Regulated (Enel, Cinergia)	2	2023-2025	200.0	41.00 – 48.00

Report Contents

3. Asset Performance: Data Overview

LAP has provided detailed performance data from 2016-2020 for Totoral and 2017-2020 for San Juan.

Data Overview

- This section summarizes both Totoral' s and San Juan's historical operational performance. Arup analysis emphasizes actual generation as well as turbine and Plant Availability. The metrics analyzed are summarized in the table below.
- Based on the SCADA data analysis, we present the sources of availability losses and we provide a summary of additional Electrical Losses that have occurred between the turbine and the meter at each facility.

Data Sources

- Monthly reports have been provided for both plants for the past five years of operations (2016-2020). These reports cover operational data such as Sold Production and availability against budgets.
- Additionally, Arup has reviewed the SCADA data made available by management, which provides operating information on 10-minute intervals and is essential in gaining a detailed understanding of any historical outages and the impact on past performance.

Data Point	Description
Production	
Budget production (GWh)	Calculated annually by LAP for the upcoming year. Their calculations are based on predicted windiness and availability and internal P50 estimates.
Sold Production (GWh	Sold Production is measured at the final meter of the plant and therefore inclusive of all losses. These figures are calculated on a monthly basis and have been provided to Arup for the period 2017-2020. Active Production is measured by SCADA at the turbine, and therefore Active Production does not include Balance of Plant (BoP) losses.
Arup's P50 (GWh)	The P50 Energy yield estimation is the output from our independent Yield Analysis and used in this section for comparison purposes.
Relative Production (index)	Sold Production over Budgeted Production
Relative Windiness (index)	Taken from the ERA5 dataset and standardized to reflect annual change in windiness from a long-term average (long term index =1.00).
Availability	
Turbine Availability (%)	Based on actual operating time of each turbine individually, compared to total possible, then averaged over the entire facility for each month. Each turbine is contractually considered "available" except during *Manufacturer Downtime* and *Unscheduled Maintenance*. This means that if a WTG is not operating for any other reason, including for example Scheduled Maintenance, Owner Downtime, or grid requested shutdowns, contractually it is still considered available. Determination of down time is based on SCADA Alarm codes. Initially, this is estimated by Vestas each month, for each turbine. Contractually, LAP has one month to review these figures, during which time they hold meetings with Vestas in order to sign-off on a contractually-binding availability figure. These may differ from those obtained directly from SCADA data.
Plant Availability (%)	A time-based availability measure based on the percentage of time that the plant as a whole is capable of producing. This includes all turbine and BoP related outages. Plant availability data is reported by management in their monthly O&M production reports, which has been the source for our analysis.

3. Asset Performance: Totoral – Generation

Based on monthly operational reports, Totoral's production has broadly exceeded the operational budget for the windfarm and is closely aligned with Arup's expected (P50) generation from the plant.

Overview

- LAP has provided monthly O&M reports for Totoral for the past five years. The reports summarize actual production, LAP's production budget, Turbine Availability and overall Park Availability.
- As shown in Figure 3.2, Relative Production over the last four years has followed a similar trend as the Relative Windiness (see Section 4 of this report for details on the long-term wind resource assessment).
- The average Sold Production for the past five years is only 1.5% below Arup's P50 estimate, indicating good alignment with expected generation.

Production Commentary

- On average, Totoral has achieved good levels of production. Generation has been broadly stable throughout Totoral's operations, averaging approximately 83.4 GWh of Active Power (measured at the turbine) and 80.1 GWh of Sold Production (measured at the substation meter).
- Relative production is the amount of Sold Power compared to the power LAP budgeted for each year, based on management predictions of resource levels, and Plant Availability.
- Overall, relative production has shown good alignment with relative wind levels, as seen in Figure 3.2. Appendix E contains more detailed information on wind resource at both plants. Since 2017, relative windiness has been relatively in line with long term trends.
- In 2020, average windiness was approximately 3.3% below the 20-year average, while generation was only 1.4% below average, indicating good performance even during this period of lower wind resource.
- During this period, availability remained high (see following pages), indicating that the decline in sold production can largely be attributed to the decline in Relative Windiness, rather than a lack of plant performance.

Figure 3.1. Historical Generation for Totoral (GWh)

Source: Arup Analysis of VDR Data

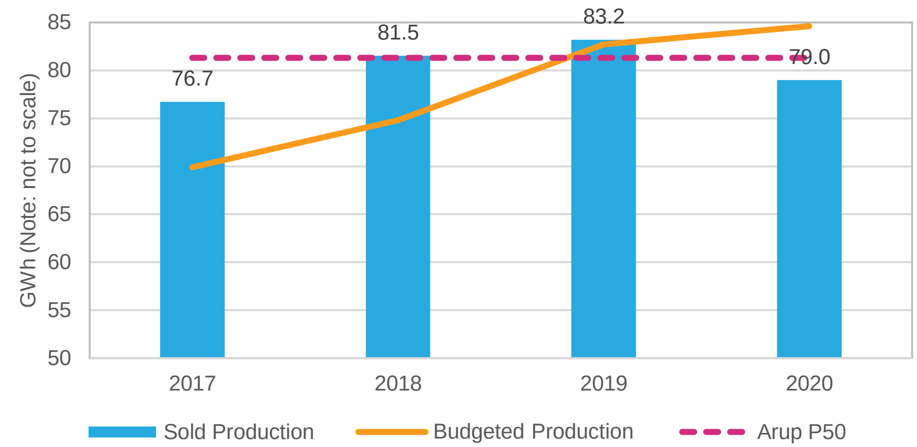
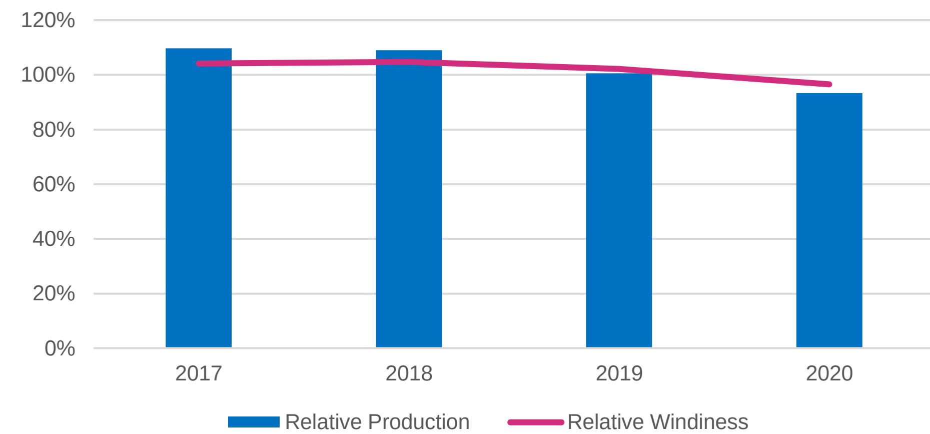


Figure 3.2. Historical Annual Availability for San Juan (Time-based %)

Source: Arup Analysis of VDR Data



3. Asset Performance: Totoral – Availability

Totoral's historical Turbine Availability has consistently exceeded the contractual requirement of 97%. Park Availability has remained stable and no historical concerns or repeated issues have been identified.

Availability Commentary

- LAP records two separate availability metrics in its O&M reports: Turbine Availability and overall Park Availability. According to the Vestas Services and Availability Agreement (SAA), Totoral's turbines are required to achieve an average annual availability of 97%.
- Arup did not receive official operational data prior to 2016; however, we understand that Totoral has exceeded the contractual availability obligation every year of operation (2010-2016). The average availability reported by LAP during these years was 98.8%.
- In the past five years of operation, Vestas has achieved an average 98.4% Turbine Availability at Totoral. This exceeds the contractual requirement of 97.0% and is indicative of adequate performance. Asset condition reviews (see Section 7) as well as historical performance suggest that Totoral should continue on a similar performance trend.
- The low Turbine Availability (97.0%) in 2017 was caused by problems in the oil filters of the turbines' gearboxes. An initial failure was triggered in May 2016. Though this failure was remedied, two more failures occurred in 2017, triggering a repair and replacement campaign that was conducted by Vestas in the first half of 2017. This was the lowest annual availability since the start of operation, and although marginally below contractual limit, LAP has not indicated that LDs were paid by Vestas. The facility has not seen evidence of ongoing issues of this type; however, Arup recommends the continued close monitoring and proactive maintenance scheme of the gearboxes.
- Overall, Park Availability has averaged 96.8% over the last five years. Park Availability considers time-based losses from turbines, balance of plant components, and the grid, and is therefore expected to be lower than the Turbine Availability, which only accounts for manufacturer downtime and unscheduled maintenance of the turbines. Arup views the difference between turbine and Plant Availability to be reasonable given the operating conditions. More discussion on losses and trends are discussed on the following page.

Figure 3.3. Historical Availability for Totoral (Time-base %)

Source: Arup Analysis of VDR Data

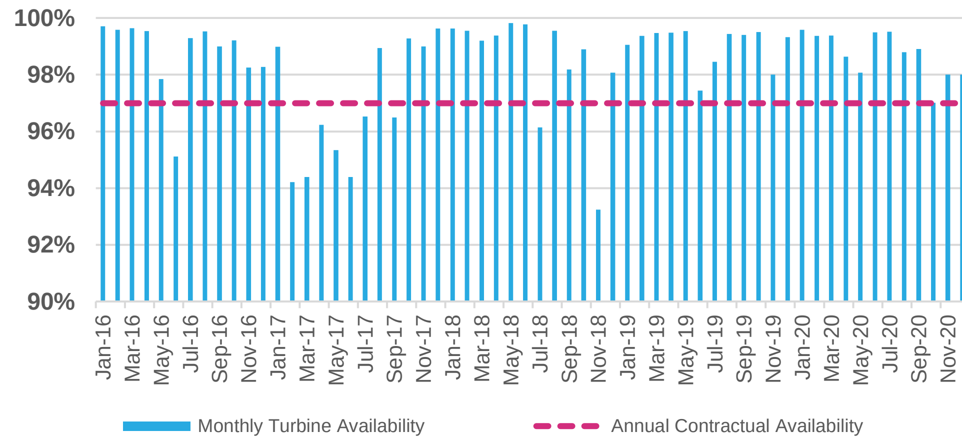
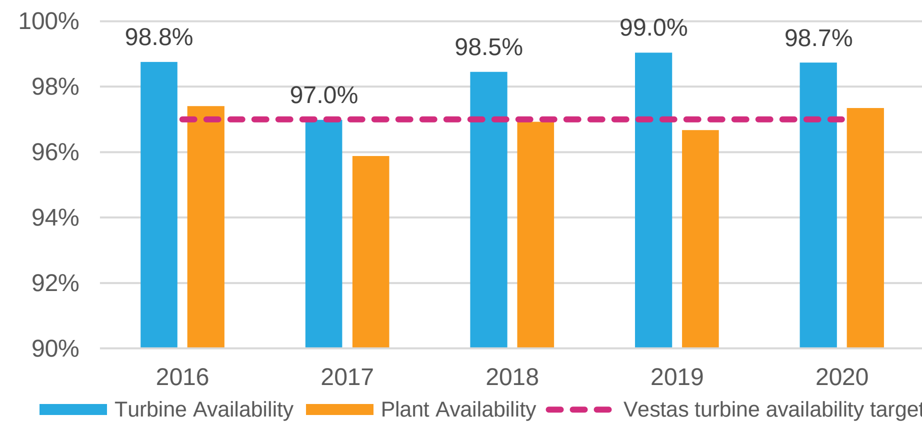


Figure 3.4. Historical Annual Availability for Totoral (Time-based %)

Source: Arup Analysis of VDR Data



3. Asset Performance: Totoral - Losses

Overall, production losses at Totoral have decreased over the last five years. This metric is indicative of LAP's management approach as well as overall improvements to the transmission network.

Production Loss Commentary

- As shown in the chart opposite (Figure 3.5), overall losses at Totoral have been decreasing over the last five years.
- In 2017, total losses at Totoral peaked (in the five-year period analyzed) at 8.46 GWh of lost generation. This corresponds to 9.9% of total Possible Production.
- In 2020, Totoral experienced only 3.11 GWh of lost generation, corresponding to 3.8% of total Possible Production.
- This improvement is driven largely by the reduction in Partial Performance losses and requested shutdowns. An average of c. 45% of the losses from 2017-2020 are classified as Partial Production Losses – that is, when a turbine is operating and generating power though not at the full capacity, given the prevailing wind conditions. A further 39% of these losses are attributed to Requested Shut-downs. Together, both types of losses saw a decline of ~70% from 2017 to 2020.
- LAP has indicated that before 2019, significant losses were due to grid curtailment. LAP attributes the improvement in the requested outages and Partial Performance losses to the implementation of the new Cardones-Polpaico 500 kV transmission line in 2019. In Arup's opinion, this is a reasonable explanation, and the park should anticipate less curtailment in the future – more in line with the 2020 level of performance.
- Electrical Losses (losses between turbine generation and export meter) have been relatively constant since 2017 at 3.7%.
  - Arup notes that this level of electrical loss is on the higher end of a typical range considering the configuration of the plant and the relatively short transmission distance to the export meter.
  - Arup recommends that a power flow study be conducted to understand the nature of these losses in order to make sure the equipment is not overheating. As well as contributing to energy losses, overheating may cause faster than anticipated wear on the system, although there is no evidence of this to date.

Figure 3.5. Annual Total Losses and Partial Production for Totoral (GWh)

Source: Arup Analysis from SCADA data and LAP budget

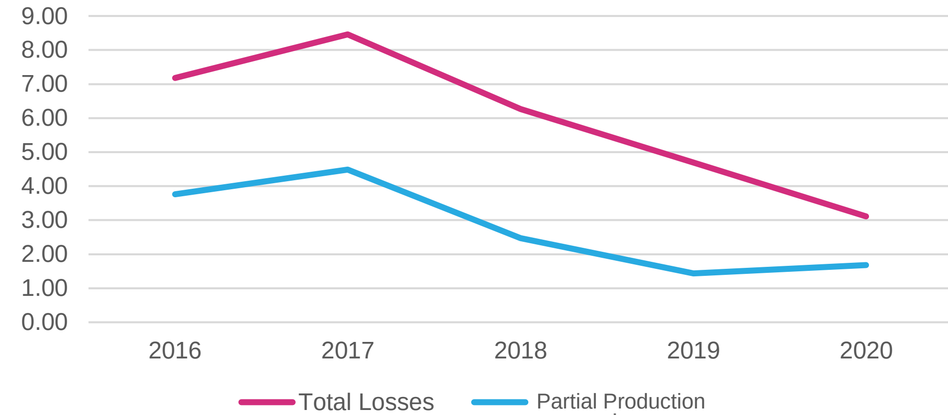
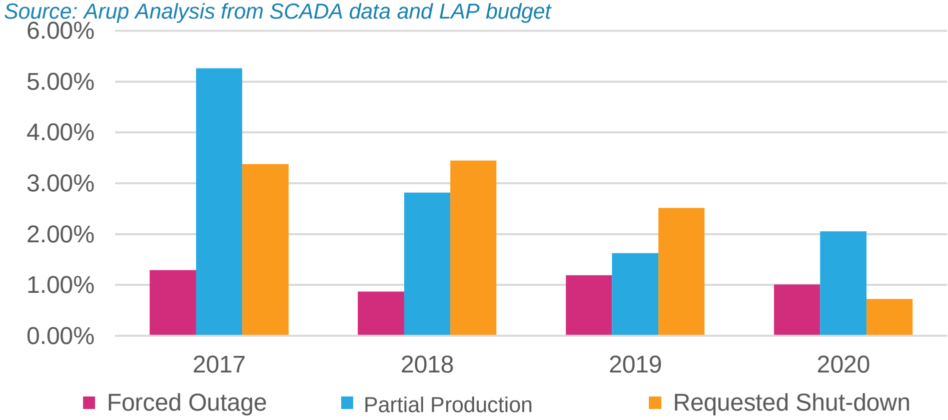


Figure 3.6. Loss categories by percent of Total Possible Generation for Totoral (%)

Source: Arup Analysis from SCADA data and LAP budget



3. Asset Performance: Totoral - Losses

The layout of the balance of plant (BoP) electrical infrastructure is considered standard. The project has developed a good operational track record since 2010 with no major operational issues.

Curtailment

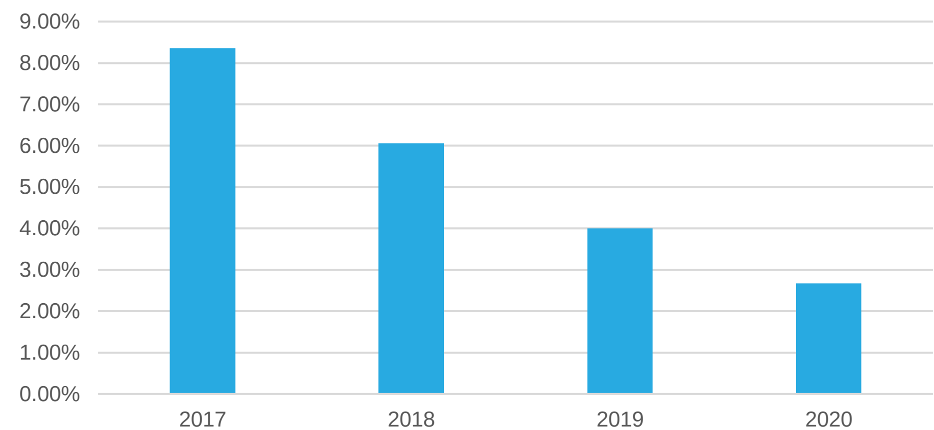
- Curtailment losses are not specifically captured by the SCADA system which does not differentiate among causes of Partial Performance.
- The point of delivery corresponds to Las Palmas switchyard which is located on the Los Vilos – Pan de Azucar 220 kV circuits belonging to SEN, the largest of the country's three distinct electricity grids.
- A relatively large number of wind energy projects are located in the vicinity of Totoral (Table 3.1) and transmit power on the same 220 kV circuits towards the same load center (Santiago).
- Arup understands that there was no grid code compliance requirement before construction of the Totoral plant, except for the need to conduct a power flow, short circuit and a harmonic study at the point of common coupling. These studies did not report any abnormal results.
- No formal log of curtailment is kept by LAP. Instead, LAP undertakes an analysis on a monthly basis, based on performance and maintenance losses. In absence of formal data, Arup has independently approximated curtailment losses as the combination of Partial Performance losses and Requested Shutdowns. These losses are presented as a percentage of total Possible Production, given the annual prevailing wind conditions in Figure 3.7 below.
- As evident in the chart, curtailment has declined over the past four years. LAP has stated that this is largely due to the addition of the 500 kV transmission line that completed the integration of the SING and SIC grids into the current SEN system.
- Arup notes that although significant improvements have been made, some level of curtailment has continued, and it will likely remain a contributor to future losses.

Table 3.1. Wind farms in the vicinity of the Project
Source : CNE

Wind Farm	COD	Capacity (MW)
Punta Colorada	2011	20
Monte Redondo	2010	48
Canela	2007	18.2
Canela II	2009	60
Talinay Poniente	2015	60.4
Punta Sierra	2019	82.6
El Arrayan	2014	115
Los Cururos	2014	109.4
Talinay Oriente	2013	90
Punta Palmeras	2014	45

Note: This table notes all wind farms in the Coquimbo region according to CNE. An additional 214 MW of solar energy is also installed in the region.

Figure 3.7. Approximate curtailment since 2017 (% Possible Production)
Source : Arup analysis of VDR data



3. Asset Performance: San Juan – Generation

San Juan has experienced high levels of production in line with expectations since the start of operations in 2017.

Overview

- LAP has provided monthly O&M reports for San Juan. The reports summarize actual production, LAP's monthly budget, Turbine Availability, and overall Park Availability.
- As shown in Figure 3.9, Relative Production over the last four years has followed a similar trend as the resource. Arup has performed a post-construction yield assessment, discussed further in Section 4 of this report, to provide an updated view of expected future yield.
- The average Sold Production for the past four years is 5.7% below Arup's P50 estimate, indicating good overall alignment with expected generation.
- As discussed on the next slide, San Juan's Turbine Availability has exceeded contractual requirements and overall park production has remained high.

Production Commentary

- Since San Juan's beginning of operation in March 2017, production has averaged 551.7 GWh per year. Since the beginning of operation, three neighboring plants surrounding San Juan have become operational. Potential wake effects are discussed further in Section 4. San Juan Neighboring plants, and their COD dates, are:
  - Cabo Leones I (CLI), southeast from the park. COD: July 2020
  - Sarco, northeast from the park. COD: June 2018
  - Cabo Leones III (CLIII), southwest from the park. COD: December 2020
- In 2020, the wind resource at San Juan was approximately 1.9% below the twenty-year average, while sold production was approximately 14% below budget. The drop in production was exacerbated by the following factors:
  - CLIII windfarm came online in 2020. Although it is too early to measure the impact of this windfarm, the wake impacts have been accounted for in Arup's independent yield forecast, as further explained in Section 4.
  - A 'Zig Zag' transformer failure event occurred in July 2020, rendering the plant only 50% operational for a period of over a month. The transformer has been repaired and Arup views this as a one-time event, which is unlikely to impact long-term production.

Figure 3.8. Historical Generation for San Juan (Annual GWh)

Source: Arup Analysis of VDR Data

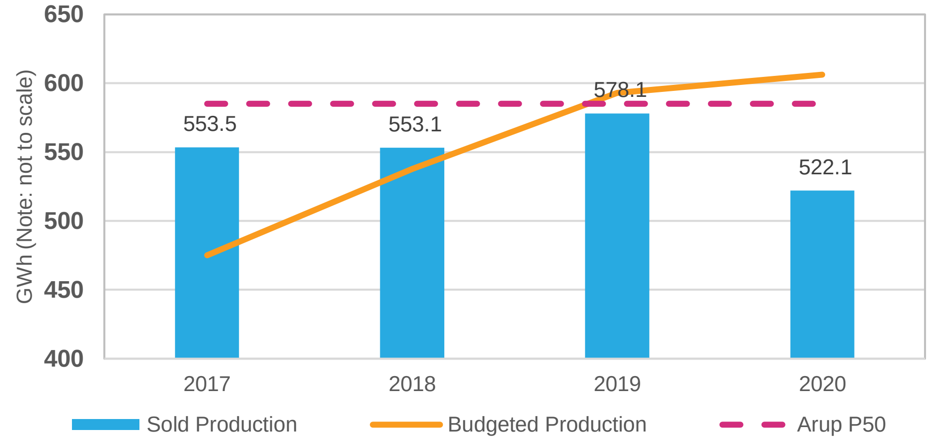
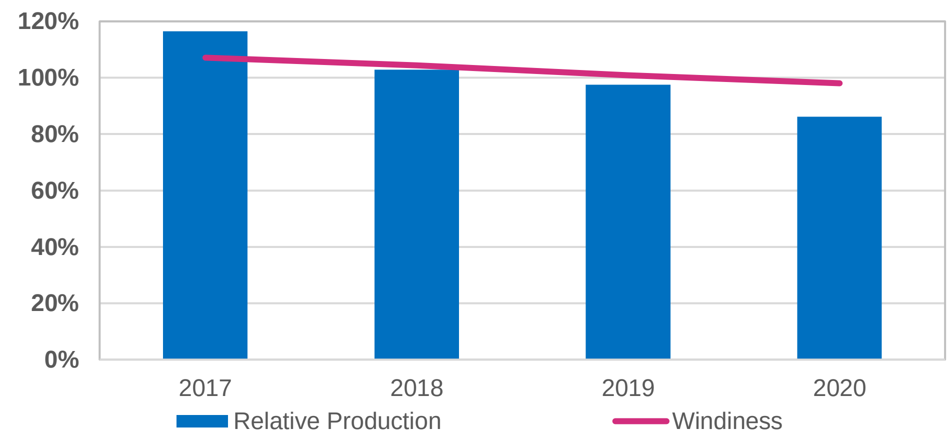


Figure 3.9. Relative Production versus Windiness Index

Source: Arup Analysis of VDR Data



3. Asset Performance: San Juan – Availability

San Juan has achieved high levels of availability every year of operations, surpassing its contractual obligations.

Availability Commentary

- According to the SAA, in the first year of operation at San Juan, the turbines were required to achieve an average availability of 95%. This escalated after contract amendments to 97% in years 2-4 and will increase 98% in year 5 for the remainder of operation. This step-wise increase in availability requirements is considered reasonable, as the early operational issues are resolved, and the plant settles into a more stable mode of operation.
- It should be noted that for San Juan, contractual annual turbine availably is calculated on a rolling 12-month basis from COD, which was March 2017.
- In the period 2017-2020, Vestas exceeded the contractual turbine availability requirement at San Juan in every year of operations; see Figure 3.11.
- Plant availability has averaged 95.1% since the beginning of operations, while Turbine Availability has averaged 98.6%.
- Plant availability has been lower than turbine-based availability as plant-based also accounts for any operational issues in the BoP that contribute to the overall availability of the windfarm to the grid. Overall, Arup views the difference between turbine and Plant Availability as reasonable.
- San Juan faced high levels of downtime in August and into September of 2020 due to failures in a zig-zag transformer. Plant and Turbine Availability were impacted in the months leading up to the failure (June – July). These issues have since been resolved and availability has returned to its high levels prior to the incident, as shown in Figure 3.10. Further details of this issue and the resolution are explained in Section 7.
- Arup notes that in 2021, the Vesta's contractual availability requirement for the turbines will increase to 98% measured on a rolling 24-month basis.
- Given San Juan's historical availability performance and the assed condition findings, Arup does not foresee challenges for Vestas to meet these new requirements.

Figure 3.10. Historical Availability for San Juan (Time-base %)

Source: Arup Analysis of VDR Data

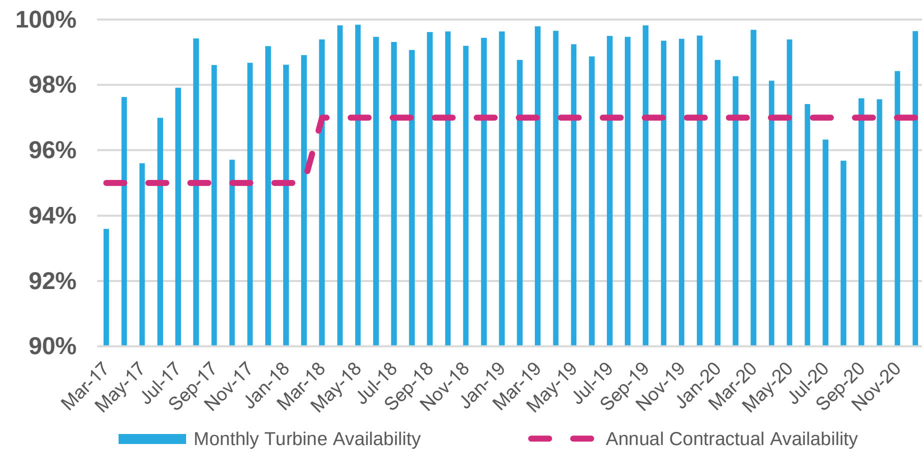
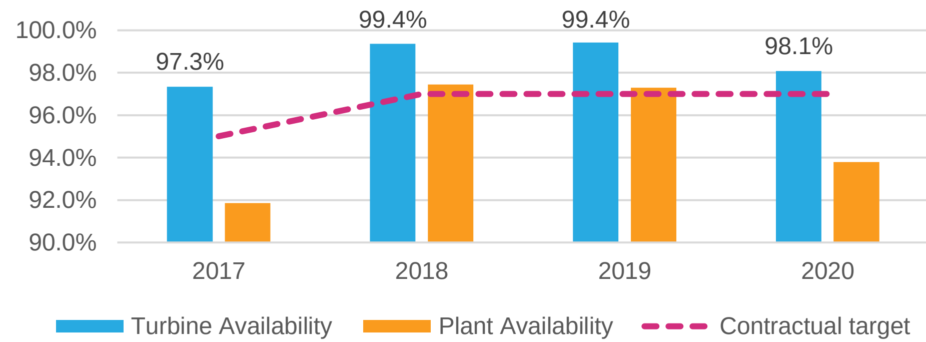


Figure 3.11. Historical Annual Availability for San Juan (Time-based %)

Source: Arup Analysis of VDR Data



Note: As an approximation, Arup has calculated the annual average availability from COD in March 2017. Each year is measured as March – February.

3. Asset Performance: San Juan - Losses

Overall losses at San Juan have been diminishing over the last five years, but increased slightly in 2020.

Production Loss Commentary

- At San Juan, total losses decreased during the first three years of operations, following start of operations in early 2017.
- In 2017, San Juan experienced 98.5 GWh of lost generation, which reduced to 20.1 GWh in 2019.
- This is expected, due to the improvement in performance following the initial ramp up of operations.
- An average of 64% of the losses from 2017-2019 are classified as Partial Production Losses – that is, when a turbine is operating and generating power though not at the full capacity given wind conditions. A further 14% is attributed to Requested Shut-downs. Together, both saw a decline of 82% from 2017 to 2019, although Partial Production losses did increase again in 2020.
- LAP has indicated that before 2019, significant losses were due to grid curtailment. LAP does not maintain a formal curtailment log, so our analysis is based on alarm losses presented in the SCADA data and Partial Performance due to curtailment cannot be explicitly isolated.
- As with Totoral, LAP attributes the decline in requested shut-downs and Partial Performance to the implementation of the new Cardones-Polpaico 500 kV transmission line in 2019. In Arup's opinion, this explanation is reasonable, and San Juan is likely to experience less curtailment losses in the future.
- Arup notes that a transformer breakdown occurred in 2020 which forced the wind farm to reduce generation by 50% for more than one month. Arup has included recommendations to ensure that the root causes of this breakdown have been addressed and the equipment can operate to its full potential. LAP assures Arup that these recommendations, aside from an energy quality study, are already in place.
- The losses noted above do not consider Electrical Losses; which are the energy losses realized between the turbines and the meter that arise as a consequence of the plant design and construction. For San Juan, Electrical Losses have averaged 3.1%. Such losses are challenging to reduce, once the plant is in operation, without significant redesign and new investment.

Figure 3.12. Annual Total Losses and Partial Production (GWh)

Source: Arup Analysis from SCADA data and LAP budget

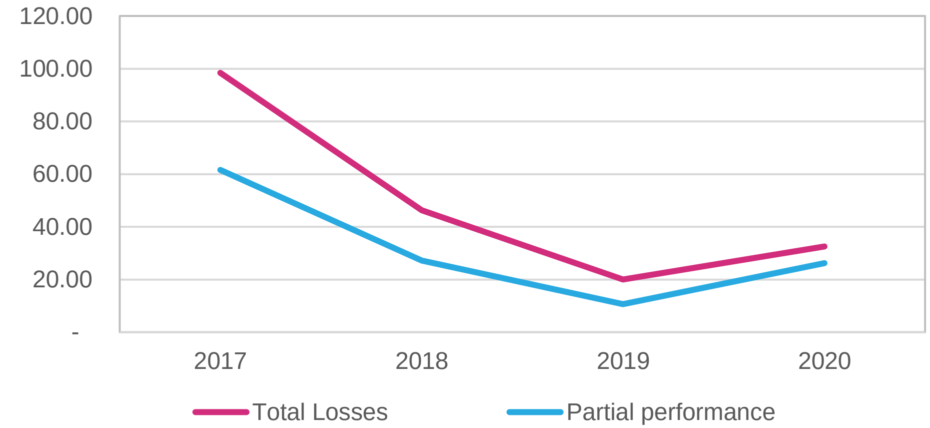
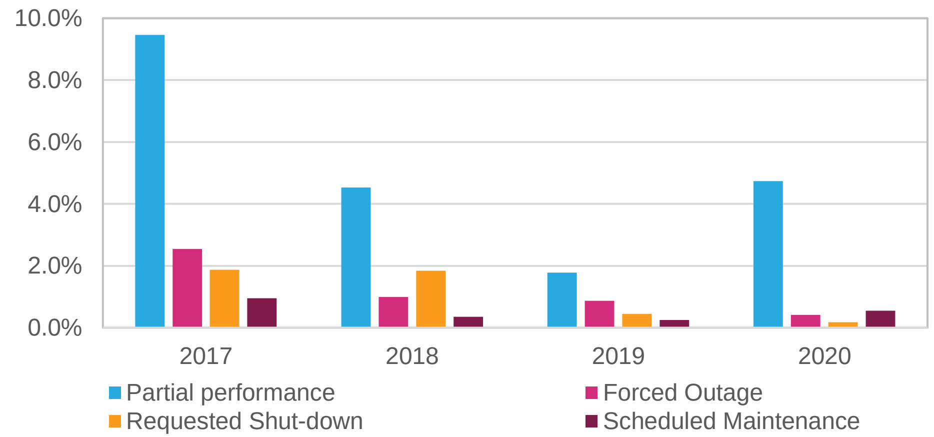


Figure 3.13. Loss categories (% of Total Possible Generation)

Source: Arup Analysis from SCADA data and LAP budget



3. Asset Performance: San Juan - Losses

The layout of the balance of plant (BoP) electrical infrastructure is considered standard. The project has developed a good operational track record since 2017 with no major operational issues.

Curtailment Losses

- Curtailment losses are not specifically captured by the SCADA system which does not differentiate among causes for Partial Performance.
- The point of delivery corresponds to Punta Colorada switchyard, which is located on the Pan de Asucar – Maitencillo 220 kV circuits belonging to SEN, the largest of the country's three distinct electricity grids.
- Although only a small number of wind farms are in the vicinity of San Juan (Table 3.2), they account for over 750 MW of capacity and all travel via SEN's 220 kV circuits towards the same load (Santiago).
- The previous Arup report noted that there was no grid code compliance requirement before construction, except for the need to conduct a power flow, short circuit and a harmonic study at the point of common coupling. These studies did not report any abnormal results.
- Arup has estimated historic curtailment based on the combination of information on Partial Performance losses and Requested Shutdowns. These losses are presented as a percentage of total Possible Production given wind conditions on an annual basis in Figure 3.14..
- As evident in Figure 3.14, curtailment has declined over the past four years. LAP has stated that this is largely due to the addition of the 500 kV transmission line that completed the integration of the SING and SIC grids into the current SEN system. Arup notes that although significant improvements have been made, curtailment has continued and will likely remain a contributor to future losses.
- For operational improvements, Arup recommends that LAP introduce more precise monitoring of curtailment at both Totoral and San Juan. Although there are limited options available to remedy high levels of curtailment, as they are a factor of the grid and outside the Operator's control, this information can provide insight into other internal issues within the windfarm, which might otherwise be falsely attributed to curtailment.

Table 3.2. Wind farm in the vicinity of the San Juan Wind Farm

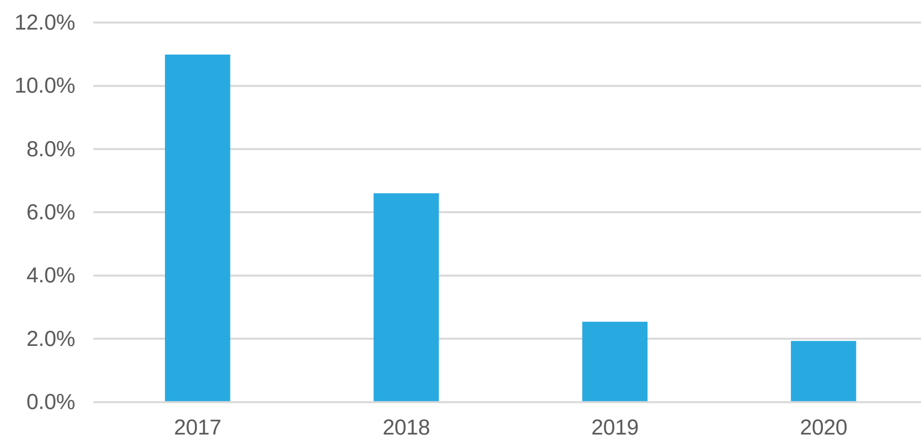
Source : CNE

Wind Farm	COD	Capacity (MW)
Sarco	2020	170.2
Cabo Leones II	2021	205.8
Cabo Leones I, III	2020	181.15

Note: This table notes all wind farms in the Atacama region according to CNE. An additional 960 MW of solar energy is also installed in the region.

Figure 3.14 San Juan approximate curtailment (% Possible Production)

Source: Arup Analysis of VDR Data



Note: Arup has excluded the months of July and August, 2020 from our estimates of curtailment. During this time, San Juan experienced high levels of Partial Performance losses due to the shortage in capacity of BoP components (see Section 7 for explanation of transformer failure). As such, Partial Performance was not a good indicator for curtailment at the time.

Report Contents

4. Yield Assessment: Summary

Arup has reviewed the operational information for Totoral and San Juan as the basis for our energy yield assessment.

Energy Yield Assessment Overview

- Arup has performed an independent energy yield assessment based on historic SCADA and alarm data for both Totoral an San Juan. As part of the original financing of the project in 2016, Arup performed a post-construction yield assessment for Totoral as well as a pre-construction assessment for San Juan, which was under construction at the time.
- Arup has used the available operating information in a post-construction yield assessment for both assets. LAP management have provided detailed information from the turbine SCADA system, including 10-minute internal information on power, wind speed, wind direction and other operating statistics, together with a log of wind farm alarms that identify periods when the system was unavailable or in curtailment.
- We also have historic information on 'sold energy volumes' at the settlement meter for each asset, which allows us to accurately assess the electrical efficiency of the assets in terms of any system losses between the turbine generator and the export meter.
- Accurate post-construction yield assessments are typically preferred over pre-construction assessments, as they can take into consideration the actual performance of the equipment on site: actual turbine efficiency, internal wake losses within the wind farm, and performance of the balance of plant. Whilst these can be estimated in a pre-construction phase, there are inherent uncertainties in this approach, which are reduced, once the plant is operating.
- However, this analysis can be more complicated, when there are new developments around the wind farms. These effects have been considered in our analysis, when new wind farms have been developed, close to the San Juan wind farm, in particular.
- For Totoral, there is a long period of stable operation from the asset with consistent exposure in terms of neighboring projects. On this basis, the post-construction yield assessment is considered to provide lower uncertainty than a pre-construction assessment and this has been used for the future yield assumption.

Table 4.1. Yield Predictions

Source: Arup Analysis

	Totoral	San Juan
Gross Yield GWh (including internal wake losses)	88.8	669.2
Wake loss factor from nearby operational assets	100.0%	87.6%[1]
Availability/Curtailment Losses	95.4%	97.2%
Electrical Efficiency	96.2%	96.9%
Degradation	100.0%	100%
Net Yield (GWh) P50	81.4	552.1
Net Yield (GWh) P90 (1 year)	70.7	478.6

*Note 1: Includes actual losses from Sarco, Cabo Leones I, and estimated wake losses from Cabo Leones III.

- For San Juan, there have been some inconsistencies in the operational period in terms of the ramp up period for the project and influences from three neighboring projects which have come online between December 2017 and July 2020.
- Whilst our post-construction yield assessment takes these effects into account, the 'clean' operating period is relatively short. As such, we consider there are also some uncertainties in the post-construction approach and so we have applied a blend of the two assessments as the basis for the future yield assessment.
- Our assessments are described in more detail on the following slides with a summary of the yield assumptions presented in Table 4.1 above.

4. Yield Assessment: Totoral Post-Construction Assessment

SCADA data has been analysed from 2017 – 2020. Moderate scatter is observed in the site power curves reflecting occasional underperformance of the plant.

SCADA Data

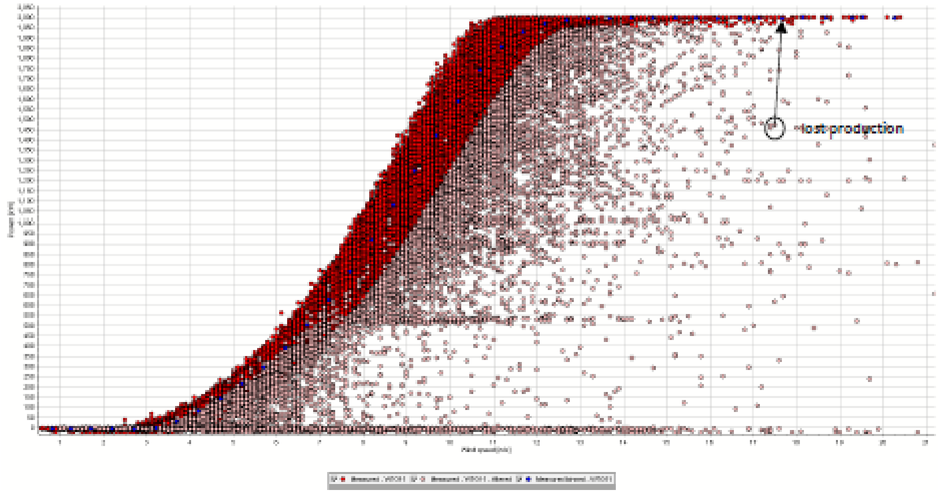
- For Totoral, SCADA data has been provided covering the period from January 2010 until December 2020 representing an 11-year period for review. Information provided includes 10-minute data (covering key performance metrics such as wind speed, wind direction and power output) and alarm logs indicating when the SCADA system identified an error or alarm which may impact performance.
- Arup has performed consistency checks on the data which indicate that similar long-term assumptions are reached regardless of how the data is analysed over time. However, there will have been changes to production over this period due to normal performance degradation and therefore the most-recent four-year period from 2017-2020 has been selected, as recent performance is more likely to be representative of future plant performance.
- The data has been compiled using the WindPRO software package and a baseline performance has been identified for all turbine locations to calculate the power curve that would be achieved under standard operating conditions.
- In the first step of the analysis, any historical downtime or curtailment events are analysed to provide a stable assessment of the gross energy generation potential of the plants at 100% availability and at standard operating conditions. Such losses, or downtime are added-back, later in the analysis.

Findings

- For Totoral, the available data is appropriate for a detailed Post Construction Yield Assessment (PCYA) and a four-year period provides sufficient data to provide a robust estimate based on operational data.
- The data review has identified some “noise” in the turbine power curves indicating occasional curtailment or underperformance events. These curtailments often occurred without an associated ‘error code’ and so our analysis allocated these events to a separate loss category for events with reduced energy production, of unknown cause. This noise is not uncommon for projects and the level of erroneous data without error codes is reasonable.

Figure 4.1. Totoral SCADA Power Curve Data

Source: Arup Analysis



- Across the operational period covered by SCADA data the average potential production was 90.5 GWh per annum if the project had performed at 100% availability and at standard operating conditions.
- The chart above shows Totoral’s power curve based on 10-min SCADA data.
- The power curve of a WTG is a graph that indicates how large the electrical output will be for the WTG at different wind speeds. Scatter points below the curve indicate Partial Performance of the turbine or other loss of production, for a given wind-speed (horizontal axis).
- It is also apparent from the power curve, that power generation is limited at high-windspeeds (see the flat top of the curve). This is a feature of the WTG design.

4. Yield Assessment: Totoral Post-Construction Assessment

Gross yield data for the operating period has been calibrated against the long-term, based on data from the EMD-WRF mesoscale dataset, with a high degree of correlation.

Long-term Correlation

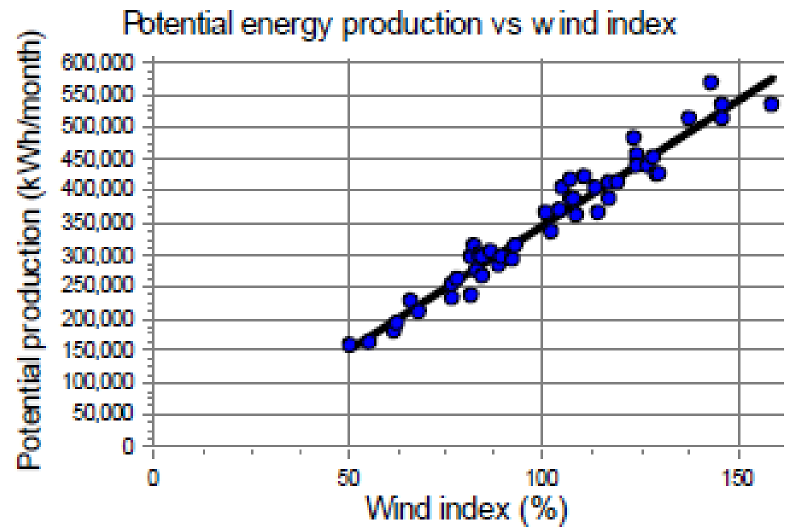
- The gross monthly yield figures calculated from the SCADA data provide a view of what the wind farm would have produced at 100% availability and standard operating conditions.
- However, wind conditions vary significantly from year to year, and so it is necessary to calibrate the wind resources from this 4-year period to the long term average – either calibrating the results upwards, in a year of low wind resource, or downwards, in a year with high wind resources.
- Arup used data from the EMD-WRF mesoscale dataset from January 2007 until December 2020 (a 14-year period). These have been correlated against the SCADA gross generation figures.
- The adjustment due to windiness of the concurrent period is 0.98, meaning that the period in our analysis (2017-2020) was ~2% less windy than a long-term average. The correlation has an R^2 of 0.93 – indicating a good relationship between these two datasets.

Project Findings

- In Arup's view, the EMD-WRF dataset is well validated in the region against other data sources and data availability for a 14-year period is sufficient to define the long-term wind climate.
- No adjustment has been made to account for any changes in future climate at this location (i.e. climate change has not been considered on this analysis).
- The resulting gross yield figure is 88.8 GWh per annum. This represents the estimated gross average (P50) yield for the future operational period. The gross capacity figure calculated is equivalent to a capacity factor of 22.0%, which is in line with our expectations for assets in this region.

Figure 4.2. Totoral Example Correlation (WTG11)

Source: Arup Analysis



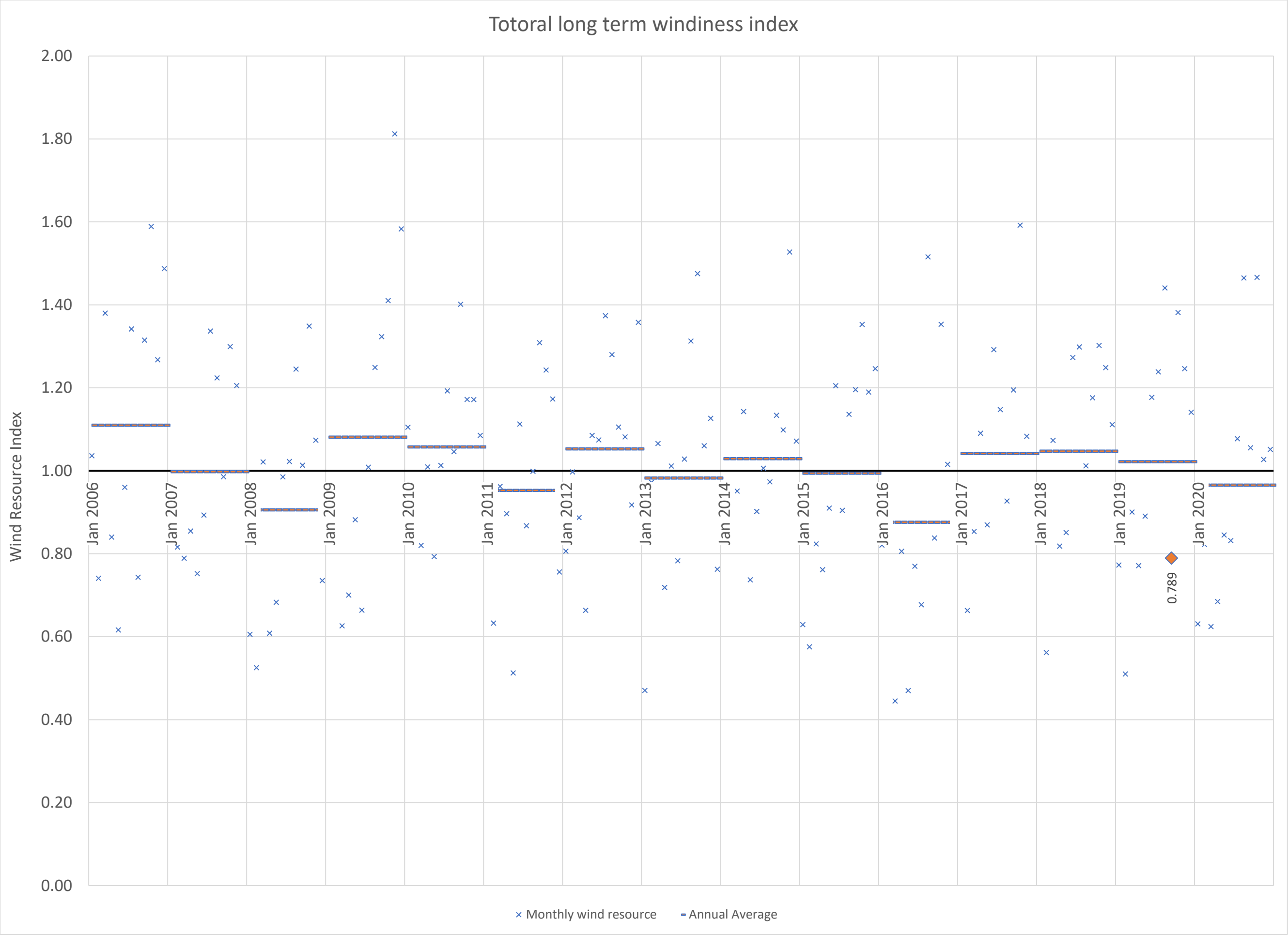
4. Yield Assessment: Totoral Post-Construction Assessment

For Totoral, the post construction yield assessment was derived from on-site SCADA information from 2017-2020, which was calibrated against the EMD-WRF mesoscale dataset from January 2006 onwards

- The chart opposite shows the monthly expected wind resource from the EMD-WRF model, which shows the variability in the wind resource on a month-to-month basis.
- This model was used to calibrate the actual output from the Totoral project, once adjusted to remove any outages or losses. i.e. the power production assuming performing at 100% availability under standard operating conditions.
- Once adjusted to remove any losses or unavailability, the power production will be influenced by the actual weather (Relative Windiness) during that month.
- Our modelling approach calibrates the actual gross energy yield, to the long-term average windiness, using this EMD-WRF dataset.
- For example, in September 2019 (see orange marker), the wind resource index for that month was 0.789, indicating a less-than-average wind resource month.
- So, the actual, measured gross energy yield for that month would be calibrated upwards based on the regression curve on the prior page, by a factor of approximately 0.211, in order to normalize the expected energy production to a long-term average.

Figure 4.3. Totoral Long-term wind resource (EMD-WRF dataset)

Source: EMD-WRF wind model



4. Yield Assessment: Totoral Post-Construction Assessment

Arup has compared historical losses identified in the SCADA data with known issues identified in our performance review to establish future loss assumptions.

Loss Assessment

- The gross yield assessment presented at the summary of this section assumes that the project performs at 100% availability with no future reductions or outages. It is also based on estimated power production at the turbine meters. As such it is necessary to apply further adjustments for the following:
  - Energy losses arising from plant, turbine or grid availability;
  - Any future performance degradation;
  - Electrical Losses between the turbine SCADA metering point and the settlement meter.

Project Findings

- The total historical losses, compared to the yield achieved under ideal situations, are 6.75% of production. These losses are split between curtailments (~3%), requested shutdowns (~3%) and Forced Outages (~1%).
- Losses were higher in 2017 and 2018, when high-levels of curtailment and shutdowns occurred. As explained in Section 3, there were problems with the Totoral turbines' gearboxes in 2017 which resulted in a large repair campaign with higher levels of unavailability in the first half of the year, as these repairs were completed. These issues are not expected to continue in future.
- Correcting for these losses and focusing on the period from 2019 and 2020 the remaining historical losses are 4.62% (~2% for curtailment, ~2% for requested shutdowns and ~1% for Forced Outages). It is also noted that these losses are consistent with the average for the period 2010-2020 (~4-5%).
- Given the length of successful operation, Arup expects limited future degradation losses and that these could be offset by improvements in the operation of the project.
- Based on historical data provided, internal Electrical Losses at the site have been 3.8%, which are assumed to continue in future. Both electrical losses and curtailment losses are accounted for in the final yield estimates.

Figure 4.4. Historical Lost Energy by Month (2017-2020)

Source: Arup Analysis

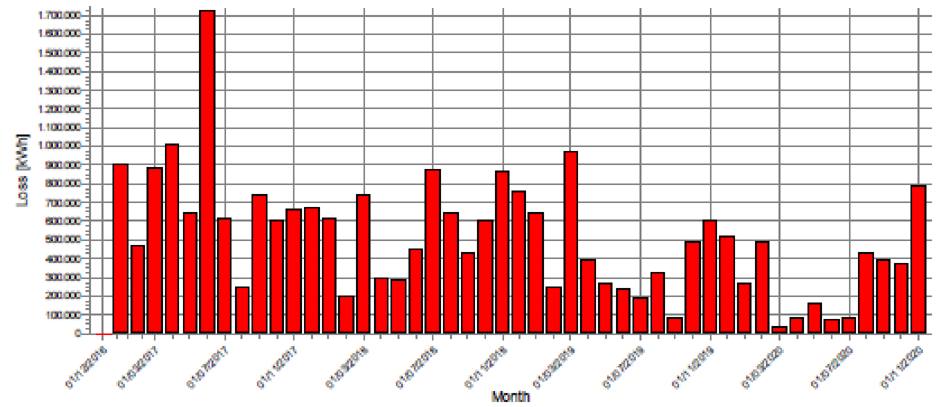
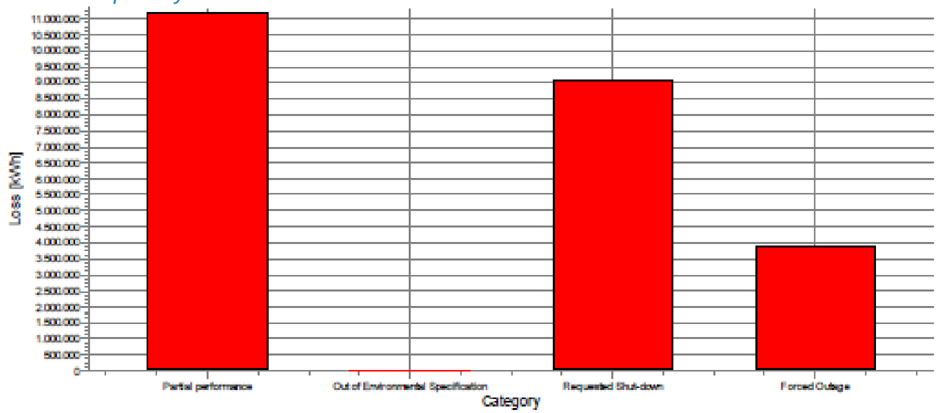


Figure 4.5. Historical Lost Category (2017-2020)

Source: Arup Analysis



4. Yield Assessment: Totoral Post-Construction Assessment

Using a Post Construction Yield Assessment, Arup estimates an annual P50 yield of 81.4GWh. For a downside case, we estimate a 1-year P90 of 70.7 GWh.

Loss Assessment

- Post Construction Yield Assessments (PCYA) studies reduce uncertainties compared to pre-construction assessments, as any pre-construction uncertainties in wake and flow modelling are captured in the operating data and uncertainties in wind measurements are removed.
- However, there are still some sources of uncertainty to be accounted for:
  - Data uncertainty for both the SCADA information and reference wind data.
  - Correlation scatter between SCADA derived monthly yield and wind speed data.
  - Representativeness of the historical wind speeds data for the future operations of the wind farm.
  - Uncertainty in the loss assumptions.

Totoral Findings

- For Totoral, the p.50 values represent the most-likely production that will occur during any particular year, with an equal probability of being higher or lower than this value. This estimated production value is 81.4GWh.
- As shown on the table opposite, within a single year, there is a 10% possibility (p90) that the production could be lower than 70.7 GWh.
- Over a longer period of 10 years, the p90 value increases to 74.6GWh, meaning that there is a 10% possibility that the average annual production could be lower than 74.6GWh p.a. within this period.
- Over a 20-year period, a similar, but smaller improvement in the annual average p90 production is shown: to 74.9GWh p.a.
- The 10-year P90/P50 ratio is within the range that Arup would typically expect for an onshore wind project, using the PCYA methodology with four years of operational data.

Table 4.2. Summary of PCYA Results

Source: Arup Analysis

	1 Year	10 Year	20 Year
Uncertainty (%)	10.3	6.5	6.2
P50 (GWh/year)		81.4	
P90 (GWh/year)	70.7	74.6	74.9
P99 (GWh/year)	61.9	69.1	69.7
P10 (GWh/year)	92.1	88.2	87.9

4. Yield Assessment: San Juan Pre-Construction Assessment

Arup completed a pre-construction yield assessment in 2016 based on data from five on-site masts. Together with new operating data from the project, a combined yield assessment is proposed.

Introduction

- For San Juan, there have been some inconsistencies in the operational period in terms of the ramp up period for the project and influences from three neighboring projects which have come online between December 2017 and July 2020.
- Whilst our post-construction yield assessment takes these effects into account, the 'clean' operating period is relatively short. As such, we consider there are also some uncertainties in the post-construction approach and so we have applied a blend of the two assessments as the basis for the future yield assessment.
- The following section first summarizes a notional 'pre-construction' assessment, before analyzing the operational data from the project in a post construction yield assessment. The corresponding, blended results are presented at the end of this section.

Assessment Summary

- Arup previously completed an assessment for the San Juan project in 2016 based on data collected by on-site meteorological masts.
- Since then, the Vestas 'Power Plus upgrade' has been installed and so this is incorporated into the base case for the project.
- The prior assessment included estimated wake effects from the neighbouring Cabo Leones I and Sarco projects, which are now operational.

On Site Measurements

- The measurement campaign on the San Juan site consisted of five meteorological masts ('Met Masts') named SJU 01 to SJU 05.
- The entire period of data availability covers a period of 67 months, or about 5½ years, of data. However, the winter months are underrepresented with two fewer winters than all other seasons.
- To ensure accurate representation across all seasons, the data used in the analysis is constrained to a full number of years. In this case, 4 years are selected from May 2012 to April 2016 with good availability of the data from these masts (98.9%).

Figure 4.6. San Juan Layout

Source: Arup Analysis

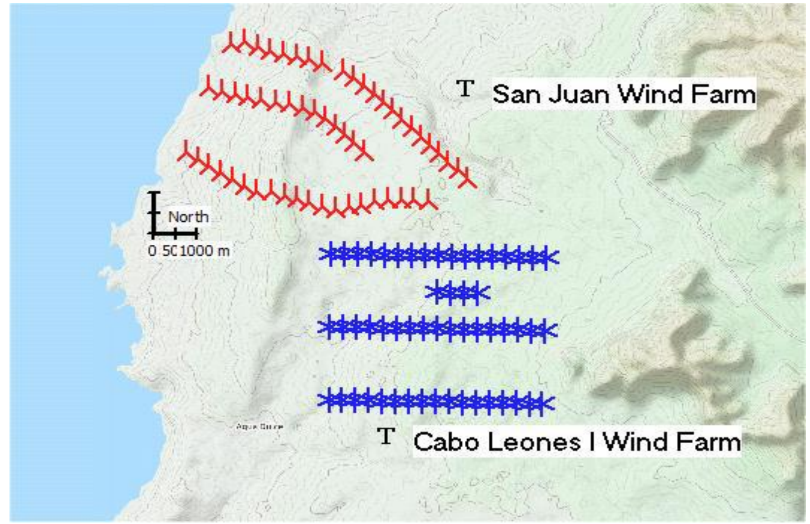


Table 4.3. Summary of Mast Data

Source: Arup Analysis

Mast	Main height	Measurement period (months)	Availability	Wind speed at 91.5 m over 4 years
SJU 01	81 m	67	98.9%	8.65 m/s
SJU 02	102 m	32	99.0%	7.87 m/s
SJU 03	102 m	40	98.9%	8.02 m/s
SJU 04	100 m	16	98.9%	7.49 m/s
SJU 05	102 m	17	98.9%	7.49 m/s

4. Yield Assessment: San Juan Pre-Construction Assessment

Four years of operating data from the project has been calibrated to the long-term based on reference data from the EMD-WRF mesoscale dataset.

Long Term Wind Resource

- Whilst four years of wind measurements from the Met Masts are available from the project, this needs to be calibrated to a long-term estimate of wind resource, in case the 4-year period is not representative of the longer-term climate.
- Based upon EMD-WRF as reference, the 20-year average wind speed is 2.4% lower than the 4 years of the measurement period.

Gross Energy Production

- The model that we have used, predicts the wind climate at each turbine in the layout. The WTG power curve, including the Power Plus function, is applied to estimate the gross annual output for each turbine.
- The gross yield and impact of the weather-bias adjustment are presented in the table opposite. The 2.4% reduction in wind speed (calibration to long-term average) is equivalent to a 3.2% reduction in energy yield.

Table 4.4. San Juan Pre-Construction Gross Yield Assessment

Source: Arup Analysis

San Juan	
Gross Yield (based on short-term site wind climate)	762.0 GWh
Adjustment for Long Term Windiness	96.8%
Gross Yield (based on long-term wind climate	737.6 GWh

4. Yield Assessment: San Juan Pre-Construction Assessment

Estimated losses were calculated for wake impacts internally and externally from the Sarco and Cabo Leones I project.

Loss Assessment

- Losses during the pre-construction assessment were assumed according to best practices and, when applicable, based on information provided by LAP at the time.
- The wake loss within the windfarm was calculated as 7.1%, without considering the now operational Cabo Leones III windfarm.
- Availability losses assumed at the time were as follows:
  - General availability loss, 3.0%
  - Grid availability, 0.5%
  - Balance of Plant, 0.5%
- The dataset was tested for high wind hysteresis losses and it was found to be negligible.
- Information from LAP management on Electrical Losses justified a value of 3.7% (i.e. factor 0.963 for Electrical Efficiency).
- The calculation assumed a 0.5% loss due to degradation.
- The resulting P50 yield assumption was 585.5 GWh per annum equivalent to a capacity factor of 34.6%.
- It should be noted that this does not include wake impacts from the Cabo Leones III project which at the time was not considered a firm project. Cabo Leones III is now operational. In the following slides we discuss the impact of the Cabo Leones III farm, as well as the potential expansion of the Cabo Leones I (Cabo Leones IV).

Table 4.5. San Juan Loss Factors

Source: Arup Analysis

San Juan	
Gross Yield (based on short-term site wind climate)	762.0 GWh
Adjustment for Long Term Windiness	96.8%
Gross Yield (based on long-term wind climate)	737.6 GWh
Internal Wake Loss	92.9%
External Wake Loss (Cabo Leones I and Sarco)[1]	93.0%
Turbine Availability	97.0%
Grid Availability	99.5%
BoP Availability	99.6%
Electrical Efficiency	96.3%
Performance Degradation	99.5%
Net P50 Yield (including Cabo Leones I and Sarco)	585.5 GWh

*Note that the external wakes and net yield values include the impacts of Cabo Leones I and Sarco but not the Cabo Leones III asset.

4. Yield Assessment: San Juan Pre-Construction Assessment

The ratio between a 10-year P90 and P50 is 0.88 which is typical for a pre construction yield assessment of an onshore windfarm.

Uncertainty Assessment

- Uncertainty is assessed as either uncertainty on wind speed or on production output. In case of wind speed uncertainty, the uncertainty is translated to production uncertainty using a sensitivity factor, which, in this case, is 1.3. This is a low sensitivity, largely due to the high wind speed on the site.
- Uncertainties relating to pre-construction yield estimates include:
  - Measurement uncertainty for both the on-site and reference wind data.
  - Correlation scatter between site and reference wind speed data.
  - Representativeness of the historical wind speeds data for the future operations of the wind farm.
  - Vertical extrapolation from measurement instruments to hub height.
  - Horizontal extrapolation from mast locations to the wind turbines.
  - Power curve performance.
  - Accuracy of wake models.
  - Uncertainty in the loss assumptions applied.

Project Findings

- The output of the notional Pre-Construction Yield Assessment for San Juan are shown in Table 4.6 opposite.
- The 10 year P90/P50 ratio is 0.88 which is typical for an onshore asset using the pre-construction methodology.
- It should be noted that the figures above include the operational Cabo Leones I project but not losses from Cabo Leones III.

Table 4.6. Summary of Pre-Construction Yield Assessment Results

Source: Arup Analysis

	1 Year	10 Year	20 Year
Uncertainty (%)	11.1	9.5	9.4
P50 (GWh/year)		585.5 [1]	
P75 (GWh/year)	541.8	548.1	548.5
P90 (GWh/year)	502.4	514.5	515.2
P90/P50	0.86	0.88	0.88

*Note that the external wakes and net yield values include the impacts of Cabo Leones I and Sarco but not the Cabo Leones III asset.

4. Yield Assessment: San Juan Post-Construction Assessment

For the Post-Construction Yield Assessment, SCADA data has been analysed from 2016 – 2020. Due to changes in the surrounding area, it has been necessary to analyse the data in shorter, consistent periods.

SCADA Data for San Juan (Post Construction Yield Assessment)

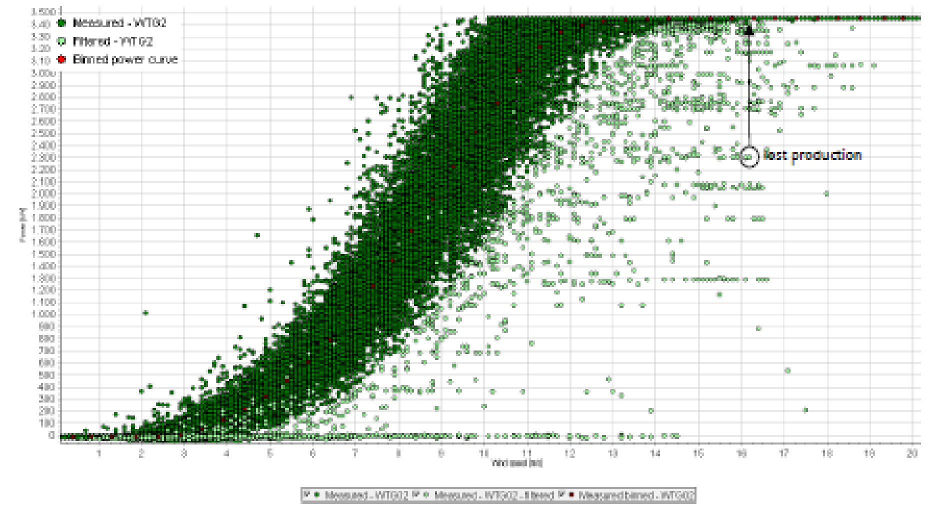
- For San Juan, SCADA data has been provided covering the period from December 2016 until December 2020 representing a 4-year period for review. Information provided includes 10-minute data (covering key performance metrics such as wind speed, wind direction and power output) and alarm logs indicating when the SCADA system identified an error or alarm which may impact performance.
- Arup performed consistency checks on the data which indicate that long term assumptions differ significantly depending on the short-term period of SCADA data selected.
- This is due to the staggered construction of neighboring projects (especially Cabo Leones I to the site) and the addition of the Power Plus function to the turbines during 2017. As such, our analysis has focused particularly on two periods of consistent data:
  - i) 2017 where the Power Plus function was installed and Cabo Leones I was not yet built and
  - ii) March 2019 – February 2020 when Cabo Leones I was fully operational, but construction had not begun on Cabo Leones III.
- The data has been compiled using the WindPRO software package and a baseline performance has been identified for all turbine locations to calculate the power curve which would be achieved under standard operating conditions. Any downtime or curtailment events have been assessed to calculate historical losses which may impact future generation.

Project Findings

- The data available is suitable to carry out a detailed PCYA; however, there is elevated uncertainty compared to a standard PCYA with four years of data due to the changes in the nearby projects described above, meaning that consistent periods are limited to one year. In general, the data coverage of the SCADA is good with limited periods of missing data.

Figure 4.7. San Juan SCADA Power Curve Data

Source: Arup Analysis



- The data review has identified some noise in the turbine power curves indicating occasional curtailment or underperformance events. These curtailments often occur without a defined error code associated and as such Arup has calculated separate loss categories for events with reduced production but no error code. This noise is not uncommon for projects and the level of erroneous data without error codes is reasonable.
- For the period with the Power Plus technology and without Cabo Leones I the average potential production was 707.0 GWh per annum if the project had performed at 100% availability and at standard operating conditions.
- For the period with Power Plus technology and Cabo Leones I operational the average potential production was 617.4 GWh per annum. During the latter period, total actual losses are low at ~3% with ~1% related to turbine curtailment events, ~1% related to Forced Outages, <1% related to each of scheduled maintenance, requested shutdowns and environmental conditions.

4. Yield Assessment: San Juan Post-Construction Assessment

Gross yields in the operating period have been calibrated to the long-term, based on the EMD-WRF mesoscale dataset.

Long-term Correlation

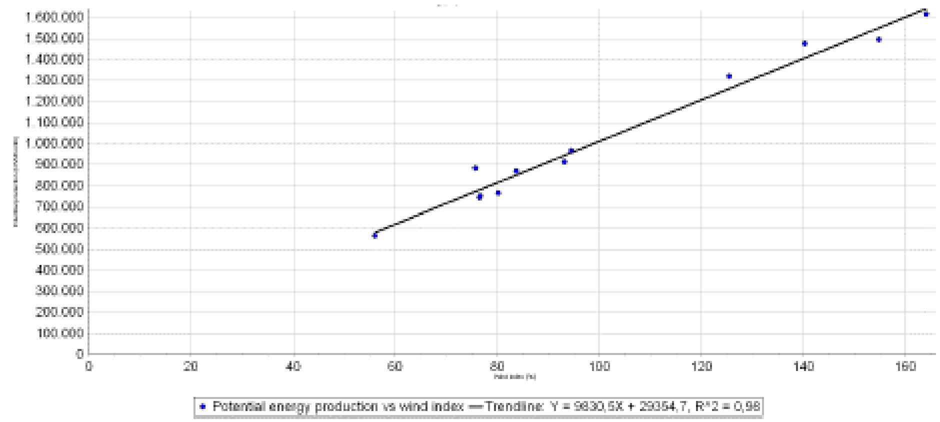
- The gross monthly yield figures calculated from the SCADA data provide a view of what the wind farm would have produced during each consistent period, assuming 100% availability and standard operating conditions.
- However, wind conditions vary significantly year-on-year and so it is necessary to calibrate these short-term values to a long-term average.
- Arup used data from the EMD-WRF mesoscale dataset from January 2006 until December 2020. These have been correlated against the operational gross generation figures for the same period.
- The adjustment due to windiness of the concurrent period for the consistent period of operations before the installation of Cabo Leones I is 0.928, which means that the period of analysis was ~7% less windy than the long-term average.
- The calibration due to windiness after the installation of Cabo Leones I is 0.983.

Project Findings

- The EMD-WRF dataset is well-validated in the region against other data sources and there is data available for a 15-year period, which is considered to be sufficient to define a long-term wind climate for this type of PCYA analysis.
- The resulting correlations are strong, which provides comfort around the reliability of the data source and the methodology applied to arrive at the gross monthly generation figures from the available SCADA data.
- Test correlations were also performed with a different mesoscale dataset (MERRA-2), which indicated a slightly greater level of adjustment, but with a poorer correlation. On this basis, the EMD-WRF dataset was applied.

Figure 4.8. San Juan Example Correlation (WTG5)

Source: Arup Analysis



- The resulting gross yield figure is 653.3 GWh per annum for the data before the construction of Cabo Leones I.
- For the period after the construction of Cabo Leones I, the gross yield figure is 611.2 GWh per annum.
- This difference, based on analysis of operational data, indicates a wake loss of 6.4% related to the Cabo Leones I project, which aligns well with the predictions from Arup’s pre-construction assessment.
- Note that the external wakes and net yield values include the impacts of Cabo Leones I and Sarco but not the Cabo Leones III asset, due to the time period used for the analysis, when CLIII was not operating.

4. Yield Assessment: San Juan Post-Construction Assessment

Arup has compared historical losses identified in the SCADA data to known issues identified in our performance review to establish future loss assumptions.

Loss Assessment

- The gross yield assessment presented at the start of this section assumes that the project performs at 100% availability with no reduction for future performance or outages and it is also based on data recorded at the turbine meters. As such it is necessary to apply further losses for:
  - Energy losses arising from plant, turbine or grid availability;
  - Any future performance degradation;
  - Electrical Losses between the turbine SCADA metering point and the settlement meter.

Project Findings

- The total historical losses for the period from March 2019-February 2020 amount to 2.73% of production. These losses are split between curtailments (~1%), Forced Outages (<1%), scheduled maintenance, requested shutdowns and environmental downtime (each < 1%). Losses were higher in earlier years as shown in Figure 4.9. Most of the losses that occurred in early years can be attributed to higher levels of curtailment, as well as ramp up outages.
- The zig-zag transformer failure in July 2020 led to significant losses in 2020. These issues are not expected to influence future availability. As such we assume that the 2.73% represents a reasonable future availability assessment for the project.
- Given the length of operation Arup would consider any additional degradation losses to be minimal. We have assumed that any future degradation losses could be offset by performance improvement measures by the Company.
- Gross energy production is measured at the turbine nacelle whereas payment is received based on values recorded at the settlement meter. Based on historical data analysed, electrical losses between these two points amount to 3.1%. This internal electrical loss is applied in the net yield assessment.
- The resulting P50 yield assumption is 572.7 GWh per annum equivalent to a capacity factor of approximately 34%. It should be noted that this does not include wake impacts from the Cabo Leones III, which became operational in December 2020.

Figure 4.9. Historical Lost Energy by Month (2017-2020)

Source: Arup Analysis

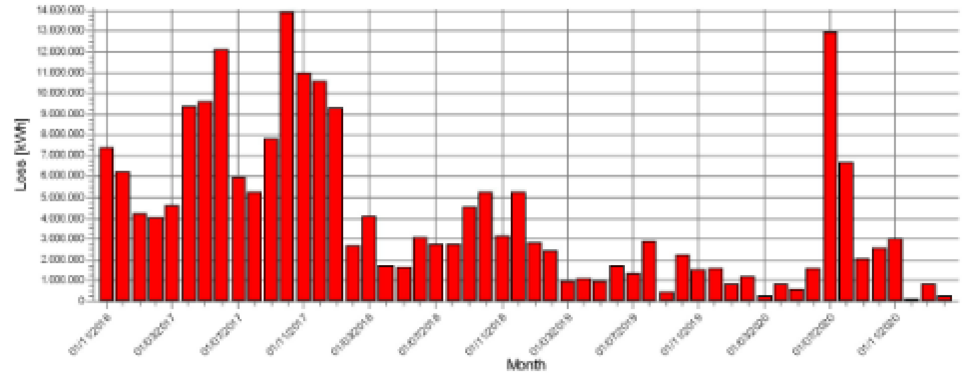
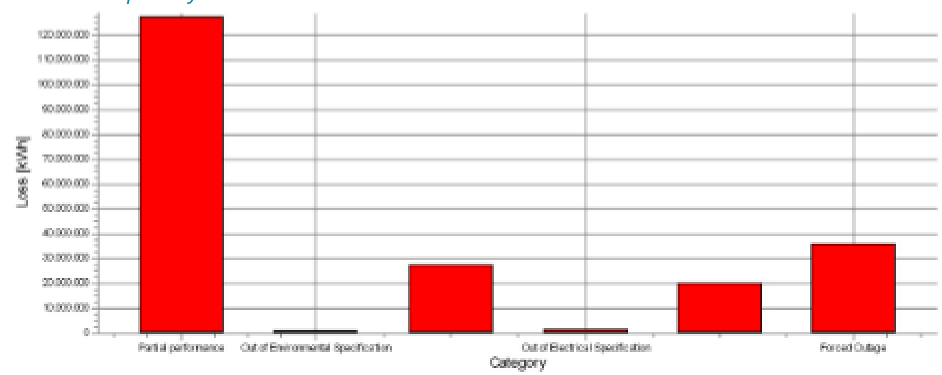


Figure 4.10. Historical Lost Category (2017-2020)

Source: Arup Analysis



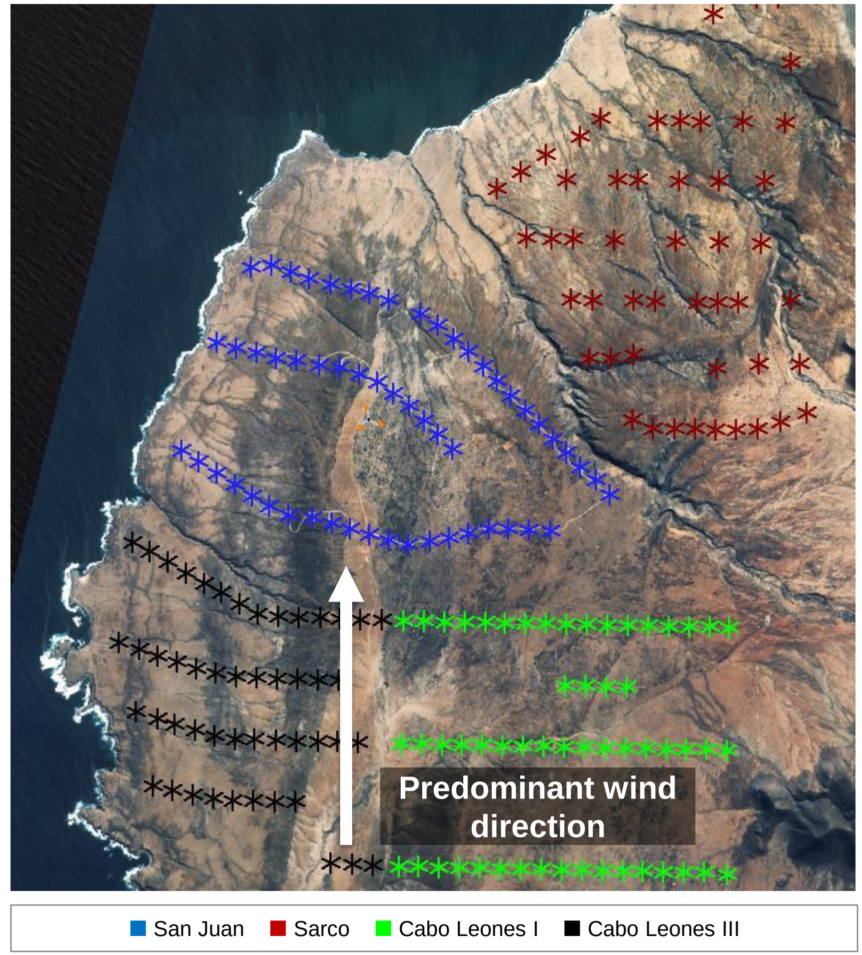
Our pre and post construction assessments do not consider the potential wake effects of the recently completed Cabo Leones III wind park, south of San Juan.

Cabo Leones III wake effects

- San Juan's layout is displayed in Figure 4.11. Cabo Leones I (green layout) began operations in December 2017. Sarco (red layout) began operations in March 2019. Finally, Cabo Leones III began operations in December 2020. Cabo Leones II (not shown in the figure), started operations in August 2020, south of Cabo Leones I. This project has limited influence on San Juan's production.
- As outlined in Arup's post-construction analysis of San Juan's SCADA data, the period analyzed between March 2019 and February 2020 did not capture the wake effects of Cabo Leones III, as this had yet to be constructed.
- Due to the recent start of operations of Cabo Leones III, constructed directly south of San Juan and along the main wind direction, Arup estimated the wake loss impact using a conventional wake modelling approach (as would be used in a pre-construction yield assessment) and the layout provided by LAP.
- The wake model suggests that a 6.0% wake loss will arise from the operation of the Cabo Leones III wind farm. Arup's wake model considers the potential future expansion of the existing Cabo Leones I, which entails the addition of 12 new units of Siemen's SG 5.0-145 to the existing park. Information of this expansion was publicly announced by Siemens in July 2020.

Figure 4.11. San Juan layout and neighboring projects

Source: LAP



4. Yield Assessment: San Juan Yield Assessment

There are uncertainties associated with both the pre-construction methodology and a post-construction yield assessment. We estimated future yield based on a combination of these approaches.

Pre- and Post-Construction Assessment Comparison and Conclusions

- Due to the impacts to the operational period from neighboring projects, there is additional uncertainty in the post-construction assessment for San Juan, compared to the Totoral project.
- Arup considers that the uncertainty associated with the pre-construction and post-construction assessments are similar and it is reasonable to use the average of these gross yield figures as the assumption for future yield.
- The losses indicated for wakes from Cabo Leones I are broadly aligned between the pre-construction model (7.0%) and the actual losses seen in operational data (6.4%). For the blended assessment, we have applied the post-construction value.
- Losses for availability and electrical efficiency are based on the actual values achieved in the operational period. Due to the operational period and the potential to implement performance improvements, we have assumed no future degradation losses.
- The resulting P50 yield assumption is 587.0 GWh per annum equivalent to a capacity factor of 34.5%. This is in line with the pre-construction net figure.

Conclusions

- Considering the points above and the additional 6.0% loss from the wake effects of Cabo Leones III, we present the conclusions of the PCYA analysis in Table 4.8.

Table 4.7. San Juan Yield Assessment Results (excl. Cabo Leones III)

Source: Arup Analysis

	Pre-Construction	Post-Construction	Blended Assessment
Yield including Internal Wake Effects GWh	685.2	653.2	Average → 669.2
External Wake Loss (Cabo Leones I and Sarco, only)	93.0%	93.6%	Post → 93.6%
Yield including External Wake Effects (Cabo Leones I and Sarco) GWh	637.3	611.2	626.4
Availability (WTG, BoP and Grid)	96.1%	97.2%	Post → 97.2%
Electrical Efficiency	96.3%	96.9%	Post → 96.9%
Performance Degradation	99.5%	100.0%	Post → 100.0%
Net P50 Yield GWh (including Cabo Leones I and Sarco wake effects)*	585.5	572.7	587.0

Table 4.8. San Juan Yield Assessment Results (incl. Cabo Leones III)

Source: Arup Analysis

	Blended Assessment
Yield including Internal Wake Effects GWh	669.2
External Wake Loss (Cabo Leones I, Sarco ***and*** Cabo Leones III)	87.6%
Yield including External Wake Effects GWh	586.2
Availability (WTG, BoP and Grid)	97.2%
Electrical Efficiency	96.9%
Performance Degradation	100.0%
Net P50 Yield GWh (GWh (including Cabo Leones I, Sarco and Cabo Leones III)	552.1

4. Yield Assessment: San Juan Assessment

Arup estimates an annual P50 yield for San Juan of 552.1GWh. For a downside case, we estimate a 1-year P90 of 478.6 GWh

Uncertainty Assessment

- PCYA studies reduce uncertainties compared to pre-construction assessments as wake and flow modelling is inherent in the results and uncertainties in wind measurements are removed. However, there are still sources of uncertainty to be accounted for:
  - Data uncertainty for both the SCADA information and reference wind data.
  - Correlation scatter between SCADA derived monthly yield and wind speed data.
  - Representativeness of the historical wind speeds data for the future operations of the wind farm.
  - Uncertainty in the loss assumptions applied.

Project Findings

- The combined uncertainties and yields for the Post Construction Yield Assessment are shown in Table 4.9 opposite.
- The figures presented consider the wake loss effects from all currently operational neighboring farms.

Table 4.9. Summary of PCYA Results

Source: Arup Analysis

	1 Year	10 Year	20 Year
Uncertainty (%)	10.4	7.6	7.4
P50 (GWh/year)		552.1	
P90 (GWh/year)	478.6	498.5	499.8
P99 (GWh/year)	418.6	454.7	457.1
P10 (GWh/year)	625.6	605.7	604.4

Report Contents

5. Financial Model Review – Totoral

O&M services for the tower and wind turbine generators are outsourced to Vestas. Contract extension will confirm these prices in the long-term, which appear reasonable to achieve a 30-year operating life.

Overview

- Arup reviewed the Financial Model (May 28,2021) inputs for Totoral which provides projections for 2021-2040 with a focus on future operating costs. Arup has not reviewed the projections for transmission wheeling, capacity, balancing costs as these items are outside the LTA's scope of work.
- The charts to the right summarise Management's assumptions with respect to the build up of operating costs over the expected 30-year operating period. Excluding WTG maintenance and maintenance of foundations, the likelihood of significant changes to annual cost assumptions is considered low. Review of the financial model inputs are summarized in Appendix F.

WTG Maintenance (Vestas Contract)

- Vestas O&M costs are assumed as USD $961k for 2021, which corresponds to approximately USD $42k per WTG / year indexed at a US CPI of ~2%. This assumption is slightly below the contract value. The financial model also assumes a one-time cost of USD $491k in 2025 to facilitate the life extension of the project. Overall, Arup considers these assumptions to be well aligned with Arup's expectations and benchmarks.
- In Arup's view, it is appropriate that O&M costs remain constant in real terms. Arup does not expect prices to increase significantly over time given that Vestas has an aligned interest to maintain the turbines per their contractual requirements and a long-term interest in maintaining and O&M contract with LAP.
- LAP has expressed interest to retain Vestas as the O&M provider for the lifetime of the project. The Company may benefit from negotiating an early renewal with Vestas.

Operations & Maintenance (BoP and other costs)

- LAP are responsible for the Balance of Plant (BOP) that is outside of the scope of the Vestas O&M contract. This covers items such as transformers, cabling, SCADA, civil infrastructure (fencing, roadways, drainage etc.). These average $760k per annum (real), or $33k per WTG/ year. In Arup view, this is a reasonable assumption, considering these components are not expected to require significant maintenance or replacement in the forecast period. It is assumed that the foundations would not require significant rehabilitation to ensure a 30-year operating life. It is assumed that this risk would be mitigated through a reduction in output of the turbines, if fatigue of the foundations was a concern in future.

Figure 5.1. Totoral - Typical Opex Breakdown (2021F)

Source: 2021.05.31 – ILAP Model (P50) HARCODED AMORT

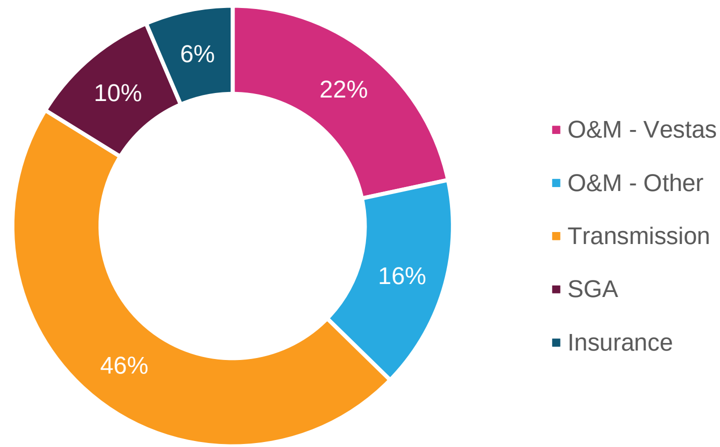
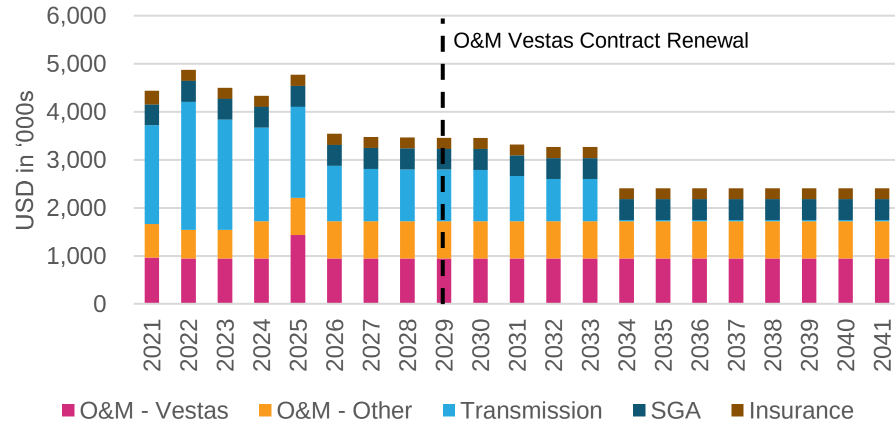


Figure 5.2. Totoral Opex Projections (USD Real 2021)

Source: 2021.05.31 – ILAP Model (P50) HARCODED AMORT



5. Financial Model Review – San Juan

O&M services for the tower and wind turbine generators are outsourced to Vestas. Contract extension will confirm these prices in the long-term, which appear reasonable to achieve a 30-year operating life.

Overview

- Arup reviewed the Financial Model (May 28,2021) inputs for San Juan which provides projections for 2021-2040 with a focus on future operating costs. Arup has not reviewed the projections for transmission wheeling, capacity and balancing costs as these items are outside the LTA's scope of work.
- The chart to the right summarises Management's assumptions with respect to the build up of operating costs over the expected 30-year operating period. Excluding WTG maintenance and maintenance of foundations, the likelihood of significant changes to annual cost assumptions is considered low. Review of the financial model inputs are summarized in Appendix F.

WTG Maintenance (Vestas contract)

- Vestas O&M costs are assumed as $3,517 million for 2021, which corresponds to USD $63k / WTG per year indexed at a US CPI of around 2% for the given period. Arup notes that the financial model also assumes a one-time cost of USD $1,196k in 2032 to facilitate the life extension of the project. Overall, Arup considers these assumptions to be well aligned with the SMA and Arup's benchmarks.
- In Arup's view, it is appropriate that O&M costs remain constant in real terms. Arup does not expect prices to increase significantly over time given that Vestas has an aligned interest to maintain the turbines per their contractual requirements and a long-term interest in maintaining and O&M contract with LAP. LAP has expressed interest to retain Vestas as the O&M provider for the lifetime of the project. The Company may benefit from negotiating an early renewal with Vestas.

Operations & Maintenance (BoP and other costs)

- LAP are responsible for the Balance of Plant (BOP) that is outside of the scope of the Vestas O&M contract. This covers items such as transformers, cabling, SCADA, civil infrastructure (fencing, roadways, drainage etc.). These average $1,263k per annum (real), or $23k per WTG/ year. In Arup view, this is a reasonable assumption, considering these components are not expected to require significant maintenance or replacement in the forecast period. It is assumed that the foundations would not require significant rehabilitation to ensure a 30-year operating life. It is assumed that this risk would be mitigated through a reduction in output of the turbines, if fatigue of the foundations was a concern in future.

Figure 5.3. San Juan - Typical Opex Breakdown (2021F)

Source: 2021.05.31 – LAP Model (P50) HARDCODED AMORT

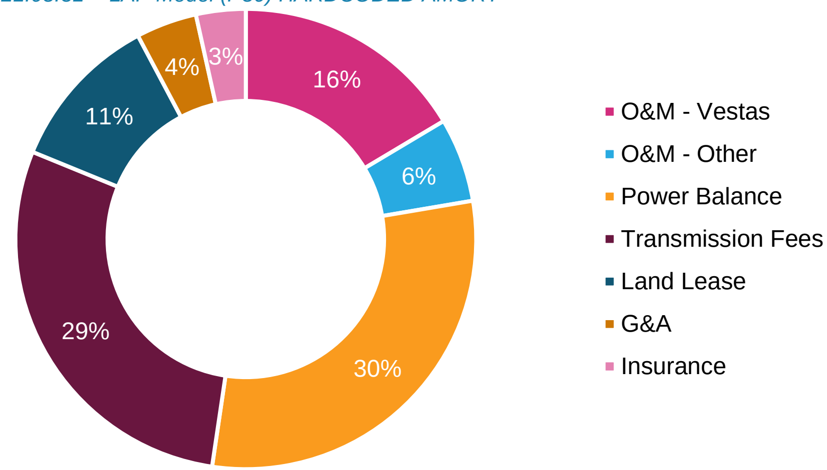
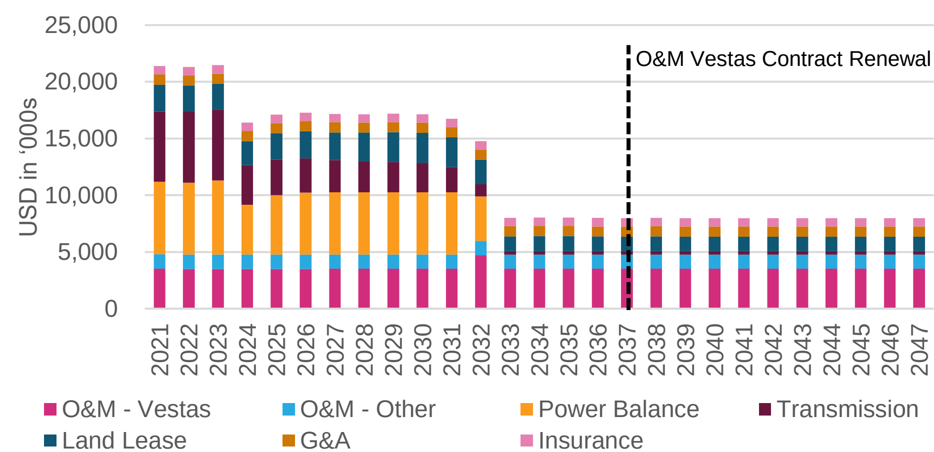


Figure 5.4. San Juan Opex Projections (USD Real 2021)

Source: 2021.05.31 – LAP Model (P50) HARDCODED AMORT



5. Financial Model Review – Benchmarking

Arup has generated a benchmarking of the WTG O&M costs using historical data from fleets around the global and proprietary projections.

WTG OpEx Benchmarking

- As we discuss later in Section 6, LAP's O&M strategy is built around a fully wrapped OEM maintenance solution for the wind turbines. Therefore, the OEM costs represent the core of future technical O&M costs for the project.
- To gain comfort around the reasonableness of the O&M projections, Arup has made an independent, component-based estimate of the O&M contract, to compare with the Vestas O&M prices that are included in the financial model.
  - Our analysis considers the major turbine components, their anticipated replacement rates over the next 20 years, as well as the labor, equipment, and spare part costs associated with these items. Our analysis also incorporates an estimate of Vesta's margin on this contract.
  - Our analysis also considers ongoing maintenance costs to maintain the turbines per the scope included in the SAA agreements.
  - Based on these assumptions, and using San Juan as the basis for calculation, we estimate the direct maintenance cost is equivalent to approximately $13.24 million over a 20-year period for the 56 turbines at San Juan.
  - Including an additional 20% cost allowance for consumables, 15% for tools and an estimated 40% profit margin for Vestas, we estimate the total cost per WTG at approximately $22,000 for San Juan.
  - This figure is lower than the 2021 contractual rates of $42k/ WTG/ year and $63k WTG/ year for Totoral and San Juan respectively, which form the basis of the long-term projections included in the financial model.
- Arup's analysis suggest that both SAAs have sufficient margin for Vestas to continue making an ample profit, even if failure rates for different components were to increase in future periods.
- Arup also notes that in recent years, other wind farms in the vicinity of the Assets were constructed and are supplied by Vestas. Economies of scale are beneficial to Vestas and should favor prices to customers such as LAP in the long term.
- From this analysis, Arup believes that the SAA costs per WTG are reasonable Also, from a commercial and market perspective, Vestas is well incentivized to ensure the long-term reliable operation of both wind farms.

Table 5.1. Summary of Estimated Maintenance Cost by Component
Source: Arup Analysis

Component	Total 20-year Cost (USD Million)		
	Routine Maintenance	Major Maintenance	Total
Rotor	2.56	0.25	2.81
Gearbox and Lubrication	0.17	2.90	3.06
Generator and Cooling	0.35	0.59	0.94
Brakes & Hydraulics	0.80	0.00	0.80
Yaw System	0.90	0.00	0.90
Control System	4.15	0.00	4.15
Electrical and Grid	0.28	0.00	0.28
Misc. (All others)	0.29	0.00	0.29
Total	**9.50**	**3.75**	**13.24**

Table 5.2. WTG Estimated Maintenance Cost Comparison to Vestas O&M
Source: Arup Analysis

Item	Addition %	Amount (USD Million)	Total (USD Million)
Direct Cost per Table 5.1	n/a	n/a	13.24
Tools and Consumables	35%	4.63	17.88
Estimated Vestas Margin	40%	7.15	25.03
Total Cost Per Year (20 years)			1.25
Comparison			
Cost per WTG – Arup estimate (San Juan, 56 WTGs)			~$22,000
Cost per WTG – SAA (Vestas contract, San Juan)			$63,000

Report Contents

6. Operations & Maintenance Strategy

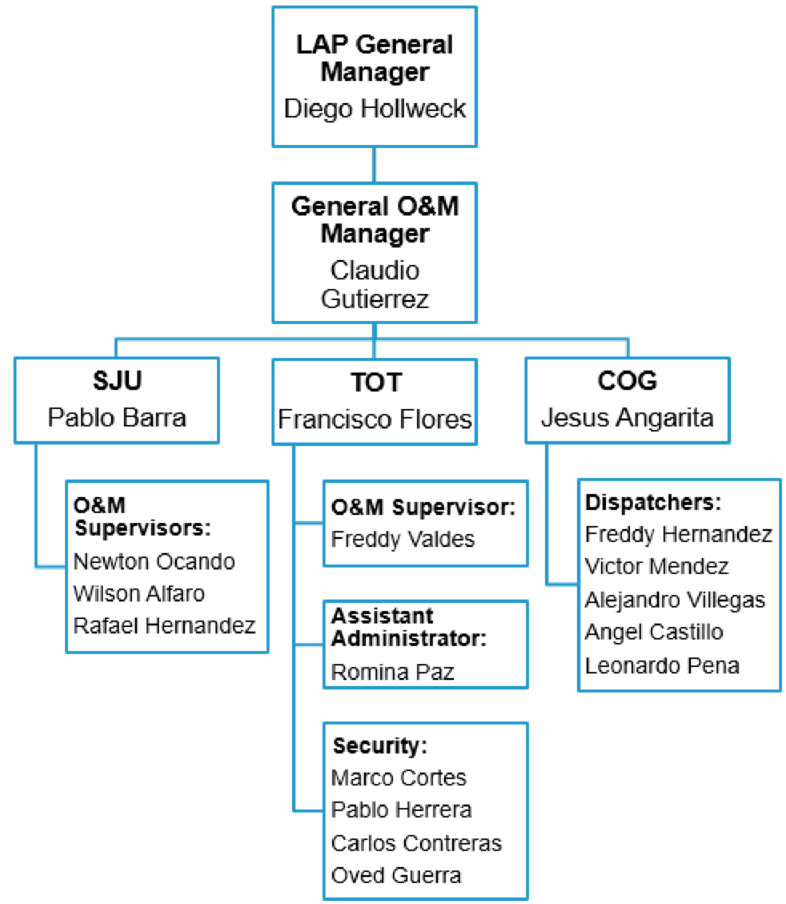
The organisational structure includes experienced personnel who are dedicated to the operations and maintenance of the two facilities.

O&M Strategy

- The O&M strategy for the Assets is built around fully wrapped OEM maintenance solution for the wind turbines.
- LAP, through each Project Company, has entered into individual Services and Availability Agreements (SAA) with Vestas, the original equipment manufacturer (OEM).
- This form of contract accounts for most controllable O&M costs and effectively transfers a substantial portion of the maintenance risk to Vestas, who are technically well placed to manage this scope effectively. This strategy is a common industry approach and is considered appropriate for a portfolio such as LAP's.
- For the operation and maintenance of the balance of plant, LAP operates an outsourced solution where local contractors are used to maintain lower-risk items such as buildings, management of the estate and substation maintenance. These local arrangements are overseen by an experienced local team of LAP employees.
- LAP O&M personnel responsibilities include the following:
  - Plan, authorize and supervise all maintenance services in the windfarms;
  - Carry out periodic independent inspections of all windfarm components;
  - Develop and execute the scheduled maintenance program;
  - Manage all resources needed to operate and maintain the windfarms
- The adjacent organizational chart shows that LAP utilizes specialized personnel from the wider LAP business as well as dedicated employees to manage San Juan and Totoral Windfarms.
- Each windfarm project company holds a balance of plant (BoP) maintenance agreement with LAP. All O&M personnel are employed by LAP – as the SPV's themselves do not have any employees.
- LAP is able to monitor the performance of their generators in real time from the generation control centre in Santiago, Chile. This operates 24/7 and 365 days per year. The Operations and Control Centre maintains a dedicated UPS and auxiliary power generator, redundant communications to both windfarms, and local operations facilities at both plants.

Figure 6.1. LAP Internal O&M organization for relevant sectors*

Source: Arup analysis of LAP information



6. Operations and Maintenance: Service and Availability Agreements

LAP maintains "Full Scope" Service and Availability Agreements with Vestas for both Totoral and San Juan.

SAA Overview

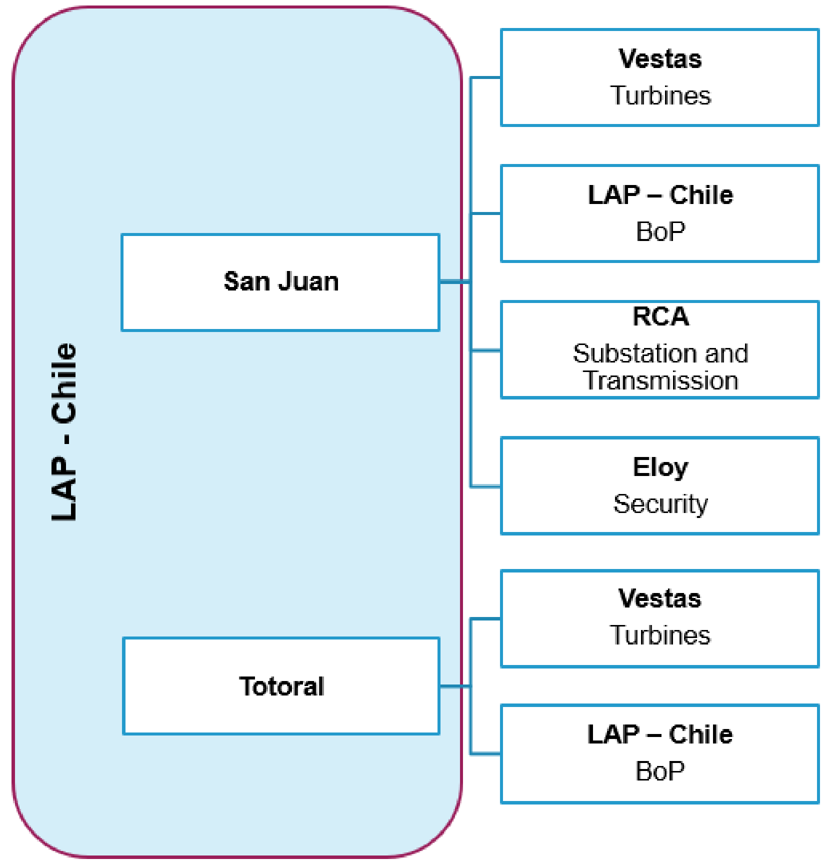
- Vestas provides Operations Services, Scheduled Maintenance, Unscheduled Maintenance, consumables, spare parts, tools and equipment for both facilities. The scope includes WTGs “Tower to top”, excluding the foundations.
- In addition, Vestas also provides 24/7 real-time monitoring, control and operation of the WTGs, including monitoring operational errors.
- The Service and Availability Agreement (SAA) with Vestas warrants an average 12-month availability of 97% for Totoral and 98% for San Juan. Should Vestas fail in providing this level of availability, liquidated damages are determined according to actual annual power output, actual energy price received, and the difference between actual and warranted availability. Vestas is incentivized through a similarly calculated bonus payment, if availability exceeds the contractual limit.

Vestas

- Vestas has a proven track record for delivering best-in-class wind turbines for more than 35 years. They have installed more than 77,000 V90 and V117 turbines, which account for more than 130 GW of installed wind power around the World. Vestas has supplied 285 turbines for projects in Chile, with a combined generating capacity of more than 580 MW.
- Vestas has maintenance contracts for more than 122 GW around the world. They maintain a global strategy of spare parts production and availability, with more than 1,000 warehouses and 21 central warehouses worldwide (One of them in Santiago, Chile). They produce turbine components such as blades, nacelles, towers, generators, controllers, as well as spare minor and assembly parts in 28 production facilities, located in strategic locations in Europe, Asia, North America, and Latin America.
- It is Arup’s view that Vestas maintains a robust supply of spare parts and are suitably experienced to manage their scope of inspections and maintenance works, as per the SAA.

Figure 6.2. Contractual Structure

Source: Arup analysis of LAP information



6. Operations and Maintenance: Service and Availability Agreements

LAP maintains "Full Scope" Service and Availability Agreements with Vestas for both Totoral and San Juan.

O&M Contract Review

- Arup has reviewed the executed O&M agreements for Totoral and San Juan. A summary of key terms is shown on the table to the right. Our review of the O&M contracts with Vestas suggests that these agreements are in line with what we would expect to see from the market for a “fully wrapped” WTG O&M agreement.
- While the agreements substantially transfers O&M risk to Vestas, both in terms of maintenance cost and availability/ performance, it is noted that there are certain exclusions which are broadly typical for the market. Key points from our review are highlighted in the following slides. For a more detailed commentary please refer to Appendix B.
- The agreement for Totoral runs until 2029. This contract does not currently extend up to the expected debt repayment in 2033, however LAP intends to extend the current contract strategy throughout the remaining asset life. This seems an appropriate and realistic strategy.
- Arup would anticipate that up to year 20 of the original design life, a scope that covers O&M contracts will be readily offered by the O&M service provider.
- Beyond the 20 years’ original design life, there is less certainty as to the affordability of full scope contracts, as this will typically depend on the historical operational performance of each windfarm. Normally, windfarms which have experienced higher than average maintenance issues and failure rates will be less attractive for provision of full scope contracts.
- The financial model currently assumes ‘life extension’ capex for Totoral in 2025 and for San Juan, in 2032 (5 years before contract expiry). This is an appropriate provision.
- To date, Totoral and San Juan have not had higher than average maintenance issues or failure rates and therefore, performance to date is considered to be in-line with normal operations and we understand that Vestas indicative pricing has been made on this basis.
- We expect that beyond the year 20 original design life, full scope contracts may be offered on reduced terms in comparison to pre-year 20 contract (e.g. 5 year terms) to enable service providers to manage their cost risk exposure (i.e., some equipment components may become excluded from the full O&M scope).

Table 6.1. WTG O&M Contract Key Terms

Source: LAP/ Arup analysis

	Totoral	San Juan
Scope	WTGs and towers (including foundation bolts)	
Term	Through March 2029 (20 years from COD)	Through March 2037 (20 years from COD)
Availability Guarantee(s)	97%	95% Year 1 97% Years 2 - 4 98% Years 5 to 20
Key activities carried out by O&M Contractor	Operation services, scheduled and unscheduled maintenance, monthly reporting, software updates, remote surveillance and spares.	

ARUP

6. Operations and Maintenance: Service and Availability Agreements

The O&M agreements for both wind parks are broadly in line with industry standards. Through these agreement, LAP is able to transfer O&M risk to a robust service provider.

Scope

- The scope of the contracts is considered comprehensive and reasonable.

Term

- The terms of the contracts were recently extended:
  - The Totoral agreement has been extended through March 2029
  - The San Juan agreement has been extended through March 2037.

Fees

- The fees are generally levied at a fixed price, per turbine basis. The tables to the right summarize the cost per WTG for different time periods for both Totoral and San Juan. Over the life of the contract, the proposed costs are considered in line with industry benchmarks. See Section 4.

Availability Guarantee

- Both contracts guarantee availability of 97% which is considered in line with the market. The San Juan agreement was amended in January 2021 to reflect an increase availability requirement of 98% from year 5 onward (March 2022).
- The contracts also feature an incentive system that pays or penalizes Vestas for outperformance or underperformance. For failure to meet the guarantee Vestas must compensate the project.
  - Arup notes that the guarantee for Totoral is based on Turbine Availability only, and not production or revenue from the project.
  - The guarantee for SJU is based on both. Arup notes that the project takes the risk for Power Curve (the actual efficiency of the turbine). This is a common arrangement in the industry.

Liability Caps

- Liability is capped under the contract at 50% of the fee paid annually for Totoral this is at the low end of what we would consider typical in the market, with liabilities up to 100% of fees paid.
- San Juan Liability cap is 100% of 5 years O&M fee. Arup believes this is a reasonable liability cap.

Table 6.2. Totoral O&M fixed fees

Source: Arup analysis of LAP information

Applicable Period	Annual Base Fee (USD $/WTG nominal)
2016-2019	26,000
2020-2024	42,500
2025-2029	45,600

Table 6.3. San Juan O&M fixed fees

Source: Arup analysis of LAP information

Applicable Period	Annual Base Fee (USD $/WTG nominal)
Year 1 to 5	63,000
Year 5 to 10	64,900
Year 10 to 15	71,900
Year 15 to 20	82,900

Exclusions

- Both agreements include industry-standard exclusions from the O&M contractor's scope and responsibility. Typically these are associated with low risk or insured events, but could mean that repair costs under some circumstances is not included under the contract. Some of the exclusion are:
  - Damage from dust storms, hail or lightning
  - Ordinary wear and tear from environmental conditions
  - Maltreatment by others
  - Force Majeure

LAP has implemented best-in-class management systems to schedule, monitor, and sign-off on maintenance activities. Key performance indicators (KPIs) are tracked and reported at various levels of the organization.

Asset Management Systems and Reporting

- LAP utilizes a cloud-based maintenance management software, *Fracttal*, to manage and monitor the maintenance of assets across all plants in Chile and Peru.
- All assets are registered in the system. Maintenance plans are input with defined activities and frequencies, along with the personnel responsible for carrying out the maintenance activities. LAP tracks and manages the activities and responsibilities of suppliers, contractors (including Vestas and RCA), customers, and internal employees using this software.
- The system generates a calendar with the programmed activities and tasks. Work Orders are then created and executed according to the predetermined schedule. LAP has indicated that they continuously monitor this program in order to ensure that all tasks are completed by the assigned parties.
- The system allows to assign responsibilities to different members of the team, as well as criticality of the activity. This provides LAP and the OEM with visibility over the most urgent tasks.
- The cloud-based system allows LAP and the OEM to collaborate in real time, scheduling, reviewing, and signing off on maintenance works. From a governance standpoint, LAP's O&M team has the ultimate responsibility to review, approve, and sign-off on maintenance activities carried out by third parties.
- The system also provides the capability to track the costs associated with maintenance.
- LAP has developed a management dashboard to track and report at the portfolio level the overall performance of the maintenance program.
- Arup views the system as satisfactory as an asset management program and a useful tool for tracking maintenance and inspection activities.

Figure 6.3. Image capture of KPI tracking via Fracttal

Source: LAP Presentation

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6. Operations and Maintenance: Asset Management Program

LAP uses a cloud-based maintenance management software to ensure that all components are inspected on a regular basis. SCADA is employed to monitor turbine activity and performance.

Overview of Maintenance Program

- LAP follows an 80/20 routine maintenance plan described as 80% predictive maintenance (scheduled) and 20% reactive maintenance (corrective).
- The maintenance activities include those carried by the OEM, local contractors, and LAP's in-house personnel.
- The table to the right shows the frequency and responsibility of routine maintenance activities performed across both windfarms. Based on this schedule, LAP has developed a short-term maintenance program.
- In Arup's opinion, LAP's maintenance strategy, program, and capabilities are considered adequate.

Operational Monitoring: SCADA Systems

- LAP's Operational Control Center is located in Santiago and provides 24/7 real time control and monitoring for all generating units. The Center is operated by the COG team consisting of five dispatchers and one manager. This team is in continuous contact with the windfarms and the Chilean energy grid, to ensure compliance with regulation and standards.
- Operational data is provided in real time, through SCADA, which records wind speeds, directions, active power, and possible power continuously in ten-minute increments.
- The WTGs have remote monitoring sensors in order to quickly identify any potential defects or abnormalities such as temperature, speed, loss of generation, oil pressure, etc.
- Since 2019, the WTG's are also equipped with real time vibration sensors. Incidents of outages, date, time, duration, and alarm code, are logged through the SCADA system.
- SCADA systems are considered best practice and utilized extensively throughout the industry for tracking WTG performance.

Table 6.4. Summary of regular maintenance and inspection activities

Source: Arup analysis of LAP information

Activity	Frequency	Party Responsible
WTG		
Drone inspection of blades	Annual	Vestas
Flange and Bolt Inspections of WTGs	Bi-monthly	Vestas
Service Maintenance of Turbines	6 months	Vestas
Post Service Inspection of Turbines	6 months	LAP
BoP		
Substation Inspections	Monthly	LAP,
Auxiliary Generator Inspection	Monthly	LAP,
Battery Bank Maintenance	6 months	LAP, Contractor
GIS 220kV Switchgear Equipment inspection	6 months	LAP,
Switch Inspections	Annual	LAP,
Transformer Inspections	Annual	LAP,
Zigzag Grounding Transformer Inspection*	Annual	LAP,
Electrical Building HVAC Equipment Maintenance	Annual	LAP, Contractor
Battery Charger Maintenance	Annual	LAP - Contractor
Disconnector Inspection	Annual	LAP,
Electric Building Boiler maintenance	Annual	LAP
Transmission Line Inspection	Annual	LAP,
General Park		
General Inspection of Park Facilities	Annually	LAP
Removal of hazardous and domestic waste	Semi-Annually	LAP – Contractor
Certification and Inspection of Elevators, Ladders, and Rails	Annually	Vestas – Contractor
Inspection of Warehouses and Inventory	Monthly	LAP
Monitoring of Bird and Bat Collisions	6 months	LAP – Contractor
Inspection and Maintenance of WTG extinguishers	Quarterly	LAP

Report Contents

7. Asset Condition: Totoral Design and Condition Overview

The 46 MW Totoral facility began commercial operations in January 2010 and is expected to continue operating until 2040.

General Design

- The Totoral farm is located in the IV Region of Coquimbo, Canela, Chile which is 295 km north of Santiago, between Pan Americana Highway and Pacific Ocean. The short distance to Santiago is considered favourable to the project as most of the country's electrical load is located around Santiago.
- The key components of the Project include:
  - 23 x Vestas V90-2.0 MW HH 80m wind turbine generators (WTGs)
  - 1 x 23/66 kV single bus bar collection substation and 50 MVA transformer
  - 1 x 66/220 kV export substation and 7km of 66 kV tap-line between the collection and the export substations
- The project uses reliable and proven technology, based on the Vestas V90 platform, who provide maintenance of the wind turbines under a fully-wrapped O&M contract which is set to expire in 2029.

Condition Summary and Life Extension

- The project experienced a number of technical issues since the start of operations. These were largely 'ramp-up' issues that now appear to have been resolved. They are not anticipated to re-occur if the Company continues to follow the maintenance practices observed to date.
  - **WTGs**: Arup has not seen any indication that the core components of the WTGs and equipment's lifetime will not be able to operate beyond 30 years. The WTGs appear to be properly maintained under the Vestas SMA contract. Arup recommends that Vestas conduct a Life Extension Program in the coming years in order to accurately assess the wear and tear on some of the main components (e.g. gearboxes). Provision for this life-extension capex is included in the financial model.
  - **Foundations:** Available inspection data for the towers, including recent 10-year inspections completed in 2020, did not highlight any major concerns. Fatigue under cyclic loading is a potential risk for the foundations. A detailed fatigue study is recommended with the next year to confirm the useful life of the foundations, along with more rigorous monitoring and inspections as noted later in this report.
  - **Balance of Plant (BOP):** Available condition data for the BoP did not highlight any major concerns.

Figure 7.1 Single Line Diagram of Totoral Wind Farm

Source: LAP

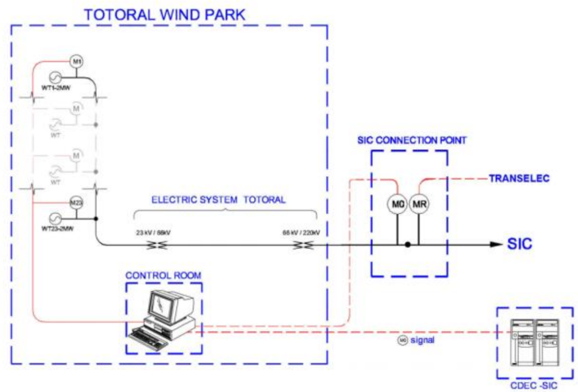


Figure 7.2. Totoral Windfarm

Source: LAP

7. Asset Condition: Totoral WTG Design (V90)

First introduced in 2000, the Vestas V90 2.0 MW turbines are designed for medium to low-wind sites with high turbulence. The V90 platform has now more than 20,500+ units installed globally.

The V90 Turbine Technical Specifications

- The adjacent diagram shows the main components of the V90-2.0 MW wind turbine generator (WTG) and the table below summarizes the main technical specifications. Arup considers the V90 platform proven and does not consider the design to be an issue.
- The turbine utilizes a microprocessor pitch control system called OptiTip and the OptiSpeedTM (variable speed). With these features, the wind turbine is able to operate the rotor at variable speed (rpm), helping to maintain the output at or near rated power. The WTG is also equipped with fault-ride through which should help with voltage stability on the grid.

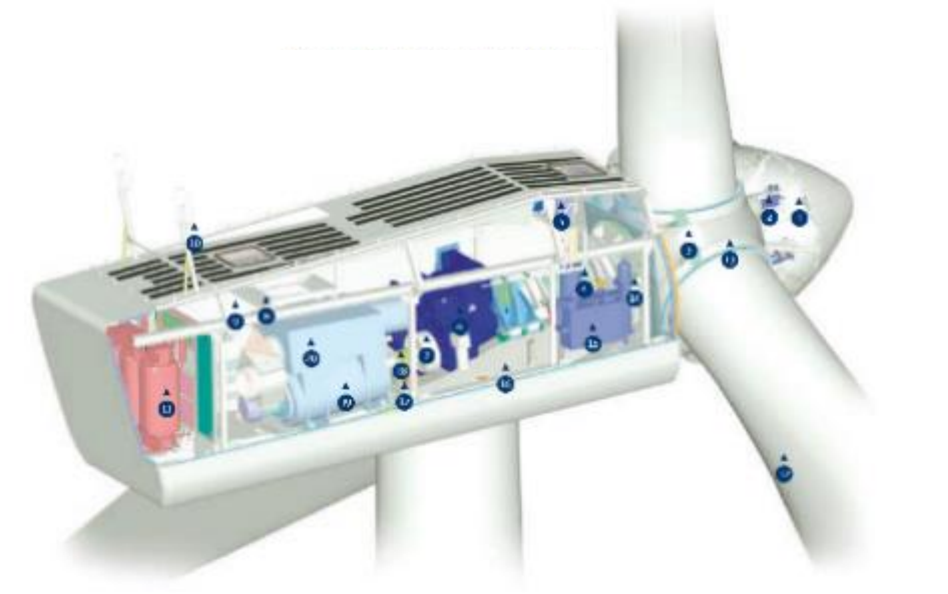
Table 7.1. Vestas V90-1.8/2.0 MW key technical specifications

Source: Vestas

Item	V90 2.0 MW IIA
Generator type	Asynchronous generator with wound rotor, slip rings and power converter (50 Hz)
Rated Power	2.0 MW / 2.2 MW (with power boost)
Converter	Partial Scale Converter (214 kW)
Blade length	44 m
Gearbox	3-stage planetary/helical
Power regulation	Pitch regulated (OptiTip/OptiSpeed)
Hub height	90.5m
Nacelle weight	68,000 kg
Rotor weight	38,000 kg
Cut-in wind speed Cut-out wind speed	4 m/s 25 m/s
Rated wind speed	12 m/s

Figure 7.3. Vestas V90-1.8/2.0 MW Components

Source: Vestas



1. Hub controller	**8.** Service crane	**15.** Hydraulic unit
2. Pitch cylinders	**9.** VMP-Top controller with converter	**16.** Machine foundation
3. Blade hub	**10.** Ultrasonic wind sensors	**17.** Yaw gears
4. Main Shaft	**11.** High voltage transformer	**18.** Composite disc coupling
5. Oil cooler	**12.** Blade	**19.** OptiSpeed generator
6. Gearbox	**13.** Blade bearing	**20.** Air cooler for generator
7. Mechanical disc brake	**14.** Rotor lock system	

7. Asset Condition: Totoral WTG Condition Assessment

LAP has provided inspection and operating reports for the wind turbine generator components. No significant issues have been seen, arising from these reports.

Methodology

- In order to assess the conditions of the WTGs, the following sets of operational documentation were provided for review:
  - 10-year inspection service report for each WTG (2020)
  - Inspection and Repairs Reports for Totoral prepared by Vestas (upon component failures between 2012 to 2019)
  - Monthly Operational Reports from 2015 to 2016 (provided by LAP)
  - Annual Operational Reports (2016 only)
- LAP reports that the aforementioned documents discuss all material repairs conducted on the plan since the beginning of operation.

Key Findings

Blades

- From the inspection reports, Minor erosion damages were noted on most turbines throughout the years.
- These damages are the result of surface erosion on the blades and required cosmetic repairs which did not appear to have had material impact on the performance of the turbines. Minor erosion on the blade is considered normal, but if left unchecked can evolve into more serious issues. Under the SMA, upon observing erosion damages, Vestas has discretion in determining if/when repairs must be conducted as these are deemed normal wear and tear. Arup considers this standard practice in the industry and does not note any issue although immediate repairs could be desirable.
- Lightning damages occurred on WTG 04 on November 2019 and necessitated significant repairs. Some regions of the world are prone to high lightning occurrences, and this can pose a significant threat to the assets. Arup did not note any indication that the site is at higher risk of lightning damages than average and no other blade seems to have experienced lightning damages. As such, Arup considers the issue closed.
- Major erosion damages were noted on various turbine blades (2, 12, 13, 14 & 18) around June 2019.
- Nine blades were dismounted and repaired on the ground, which resulted in substantial downtime during the repair period. Arup does not note any issue with respect to the workmanship around the repairs and note that DNV GL was hired to supervise Vestas' crew during the repairs which is considered good practice.
- Arup reviewed the DNV GL report that provides a comprehensive root cause analysis of the damage. It was concluded that the issue occurred due to a condition of "edgewise vibration" which is caused by the inability of the yaw system to yaw the blades against the wind direction when the turbine is at a full stop.
- LAP indicated that during that year, it experienced significant grid outages and the electrical equipment could not be operated during these outages. Where sudden wind gusts took place and the yaw system failed, the blades would experience edgewise vibrations and would ultimately result in significant lamination damages.
- Management indicated that they now have a back-up generator available on site which they intend to use to operate the WTG yaw systems during any future outage. Arup requested and did not receive management's clarification regarding the sufficiency of only one back-up for the entire project.

7. Asset Condition: Totoral WTG Condition Assessment (Cont.)

LAP management have provided inspection and operating reports for the wind turbine generator components. No significant issues have been seen, arising from these reports.

Gearbox

- Critical failures on WTG 01 (January 11, 2017) and WTG 16 (May 12, 2016) were observed following an alarm and subsequent inspections:
  - *WTG 01* experienced a bearing failure on the outer ring of the third bearing and had to be completely replaced. Early signs of failure were observed on January 29th 2014 based on the vibration analysis. At that time, Vestas concluded that there was a misalignment between the intermediate and high speed shaft and recommended more frequent inspections. It is unknown whether the recommendation was implemented until two years later when the catastrophic failure took place.
  - *WTG 16* had experienced a number of such alarm events in the previous months and high content of magnetic particles were detected after analysis of the oil sample. Preventative gearbox inspections were then requested in all other turbines which Arup considers commendable practice. The gearbox had to be replaced and the WTG lost more than (6) months of production.
- Early signs of potential failure were detected on WTG 19 (December 27th 2016) after an alarm was trigged for high PQ index in the gear lubricant. Micro-pitting was observed. Vestas classified the defect as normal wear and tear and that it would not affect the operational of the WTG and recommended that the gearbox be inspected every two months. It is unclear if these practices were implemented by LAP in the long term; however, after the series of incidents and failures in late 2016 and early 2017, LAP did implement a major inspection and repair campaign across all turbines in 2017.
- Gearboxes are critical and expected to last for at least 20 years. The failures that were experienced after less than 6 years of operation are not desirable, but Arup considers that Vestas displayed proactiveness by ordering a preventive inspection on all gearboxes following the failure on WTG 16 in 2016. Under the SMA contract, Vestas are incentivized to monitor the condition of the gearboxes in a way that should ensure continued operation of the gearboxes during the remaining contract period. The successful operation of the gearboxes since indicates no serious manufacturing defects.
- Nonetheless, Arup would consider it prudent to conduct a borescope inspection on a reasonable sample (c. 10%) of the WTGs to ensure that the condition of the gearboxes are within the normal wear and tear that is expected at this stage in life.

Yaw Gear

- Critical failures on WTG 07 (September 2013), WTG 08 (August 24th 2015) and WTG 21 (September 21st 2013) were observed and the yaw gears had to be replaced. Insufficient oil lubrication was deemed the root cause of the failure and maintenance practices were corrected. According to the information Arup has received, there have been no subsequent major issues with yaw gear.

Generators

- Minor defects were observed occurred on WTG 04 and WTG 09 where slip rings brushes were replaced or simply cleaned.
- Arup did not note any other repairs associated with the generators and based on the documentation provided, the generators appear in good condition and maintenance practices correctly followed.

Transformer Repairs

- Partial discharge defects were observed on WTG 08, 11, 14, 17, 18, 20 and 23 around September to October 2013. The transformers had been affected by electricity treeing discharge and the dielectric on the transformer windings had to be replaced. The WTGs lost one day of production due to these repairs and Vestas adjusted its maintenance practice to monitor the condition of the dry transformers every 9 months. It was concluded that the failures were due to high concentration of sea salt and humidity. Vestas recommended to improve the closure of the nacelle in order to limit salt incursions.
- Arup has not received evidence that these closures were implemented and recommends this action take place, if not already.
- Arup requests confirmation that the humidity in the nacelle is now maintained within the proper range and that no further discharge issues have been noted since.

7. Asset Condition: Totoral WTG Towers

Industry-standard Vestas tubular-steel towers have been used, which have a certified life of at least 20 years. They are typically imported and transported to the site from the nearest Vestas' certified vendor.

Towers – Design Review

- The WTGs and their supporting structures are designed to operate in a wind climate equivalent to their respective IEC class, in line with the design standard: IEC 61400-1. This classification is appropriate, in terms of structural loading, for the expected site conditions.
- Although the details of the tower design and the supporting calculations are proprietary information of Vestas and are not available for review, Vestas will have performed exhaustive fatigue-load analyses on the blades, nacelle and tower structures. These fatigue-load analyses and assumptions have been independently certified by DNV-GL.
- If life extension beyond the original design life (20 years) is anticipated, Vestas offers a life extension programme as part of their standard operation and maintenance service:
  - Vestas offers this option at any time, but it becomes more relevant near the end of life of the project (i.e. around 15-20 years of operation).
  - The life extension programme consists of a thorough assessment of the turbines' condition, including an analysis based on historical operational data (site-based fatigue assessment) and a review of maintenance logs and design specifications. This enables the expected remaining lifetime of the turbine to be determined and any additional maintenance investment to be undertaken.
  - If no problems are identified during the assessment, a report is provided to the asset owner, confirming safe continued operations. Otherwise, a list of remedial works are provided to the owner for their action.
- LAP are discussing with Vestas to purchase the life extension programme for up to 30 years for the Totoral WTGs. At the time of this report, this assessment has not yet been started and will begin in 2025 as mentioned in Section 5.

Towers – Condition Assessment

- Available inspection data for the towers, including recent 10-year inspections completed in 2020, did not highlight any major concerns.
- The primary maintenance work on the towers has consisted of coating repairs at the base of the tower, which was completed in 2019-2020.

Figure 7.4. tower internals from inspection report

Reporte Fotografico Post Teremoto WTG04, 2015

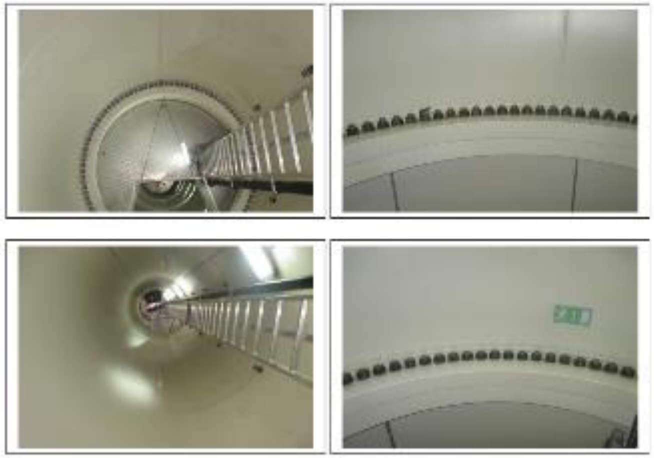


Figure 7.5. Example coating repairs (2019)

Informe de reparacion bases de aerogeneradores ano 2020

7. Asset Condition: Totoral WTG Foundations

Gravity based concrete foundations are used for Totoral which is typical within the industry. The connection to the tower is formed by the commonly used 'Insert Can' connection.

Foundations – Design Review

- The structural foundations of each wind turbine are a critical part of the overall structure, providing stability for the wind turbine generator, through the tower.
- The rotation of the wind turbine and the varying stresses caused by the wind direction, gusting and turbulence, mean that the foundation structure receives significant cyclic loading, and fatigue is a key consideration in the assessment of the useful life of the wind farm.
- The design of the foundations was completed by Ogup y Asociados Ingeniería Estructural ltda, who are a local Chilean engineering firm; now part of the larger Spanish group: FHECOR.
- The WTG is designed for a certain wind regime (e.g. Wind Class: IEC IIIA). The turbine manufacturer provides the resulting ultimate and fatigue loads acting on the foundation for use by the foundation designer.
- Typically, WTG foundations are fatigue-constrained in their design. That is, they are designed for a specified number of stress cycles over their lifetime, before there is naturally an increased risk of structural failure of the foundations, as the foundations and the WTG get older.
- The Totoral foundations are gravity based (i.e. weight of the foundation and backfill is used to prevent uplift) and they are fabricated from cast-in-place reinforced concrete. The foundations are square on plan, with a length of 14.5m
- The connection to the tower is formed using an insert-can, which is a typical connection detail. An insert can is a short section of tower that is cast into the concrete foundation.
  - Above the concrete, the insert can has a top flange for connection to the wind turbine tower. Embedded in the concrete at the bottom, there is a flange to provide restraint within the concrete.
  - Most load is transferred to the foundation through compression above and below the flange.
- Ground or rock anchors are used to reduce the overall foundation size and help prevent uplift. These are commonly used details.

Figure 7.6. Plan drawing of foundation

0028-01-H-PL-0101-AB

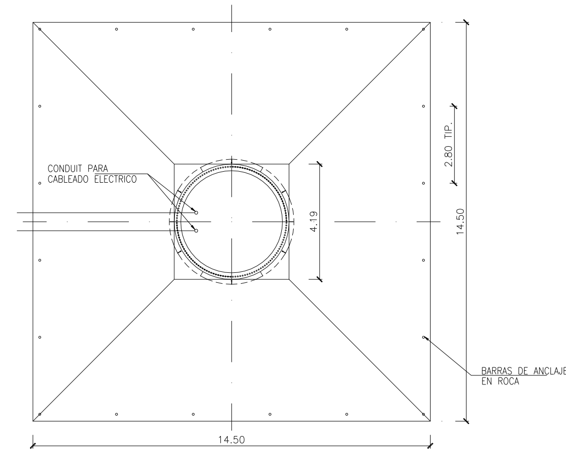
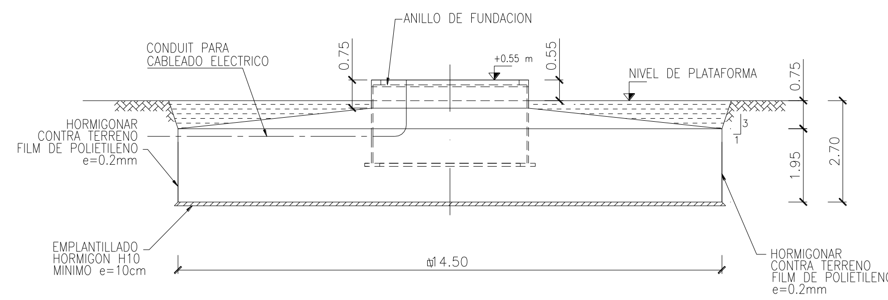


Figure 7.7. Elevation drawing of foundation

0028-01-H-PL-0101-AB



7. Asset Condition: Totoral WTG Foundations (Cont.)

WTG foundations are subjected to cyclic stress loading induced by wind. A detailed life extension study is recommended to confirm the useful life of the foundations, along with rigorous monitoring and inspections.

Foundations – Design Review (Cont.)

- The foundations for the WTG are a key component in the overall wind park and the projected life of the asset. Should any problems arise during the operational phase, these can often be uneconomic to repair.
- On this basis, the validation of an appropriate design and verification of construction quality are important to ensure that a useful life of more than 20 years for the foundations can be expected.
- As noted earlier, for Totoral, the design solution applied for the foundations are gravity foundations with rock anchors and an insert-can connection detail. In Arup's experience, these details have been prone to problems in other wind farms, although the designs for Totoral have been adapted to minimize these problems.
- Arup has not completed an in-depth design review of the foundation design or independent fatigue calculations as part of our scope of work. Although no fundamental flaws have been identified with the design, a high-level review of the documentation available reveals that the fatigue analysis completed during the design was limited.
- An independent review of the foundations was completed in 2016 by a third-party consultant, which indicated the foundations were acceptable for 30 years of operation; however, the fatigue analysis presented in this report is also limited. Arup recommends LAP conduct a detailed assessment, following industry-accepted standards such DNVGL-ST-C502 (the standard for reinforced fatigue design in the wind energy industry) to properly quantify the risk of fatigue damage. We recommend that LAP completes this study within the next year.
- Management has indicated that they intend to follow this recommendation with respect to this analysis.
- Until this study is conducted, Arup recommends to conduct a sensitivity analysis where the project would experience a production loss of 2% from year 15 due to active power management. Active power management could be necessary in order to ensure that fatigue loads stay within the design envelope.

Foundations – Condition Assessment

- From the maintenance documentation available, it is not evident that regular monitoring of the foundation beyond visual inspections is being completed – for example monitoring potential concrete cracking, backfill erosion, foundation settlement, and importantly, any changes in tower verticality.
- In Arup's view, it would be prudent to undertake more rigorous ongoing monitoring of the foundations. This should include monitoring of tower verticality, regular concrete inspections, checking for signs of deterioration at the insert can interface and monitoring of backfill cover. Whilst preventative maintenance may be difficult due to lack of access to the reinforcement bars and rock anchors – rigorous monitoring will allow LAP to better asses the signs of fatigue and risks of foundation deterioration, and take corrective operating actions such as reducing turbine output, etc. Management has indicated that they intend to follow this recommendation with respect to monitoring.

Figure 7.8. WTG 3 Foundation showing backfill

10.2.1.4 130204_TOT_Inproin_INFORME DE REVISION TECNICA DE FUNCIONAMIENTO

7. Asset Condition: Totoral BoP

The layout of the balance of plant (BoP) electrical infrastructure is considered standard. The project has developed a good operational track record since 2010 with no major operational issues.

Totoral BoP Design

- The BoP contractor was Skanska and the electrical engineer of record was Ogup. The wind farm was developed by SN Power (Statkfraft) – a Norwegian company that owns and operates hydroelectric assets in Chile and established in 2002 . SN Power developed and helped finance the wind farm together with IFC.
- As per the single line diagram prepared by NorVind, the BoP is mainly comprised of :
  - (1) 23/66kV wind farm collection substation ;
  - (1) 66/220kV export substation ;
  - 7 km of 66kV overhead between the collection and the export substation
  - 0.3 km tap-line from the export substation to switchyard (Las Palmas)

BoP – Overall Condition Assessment

- The project was co-financed by IFC which requires a suitable EPC contractor to undertake the BoP scope Skanska and Ogup are relatively experienced in the construction of large infrastructure projects and using primary products from internationally recognized OEMs
- Continuous performance monitoring, routine schedule maintenance, inspection, condition monitoring, and testing are all used to detect deterioration of condition or degradation of performance of BoP
- Arup recommends to add the cable inspection (cables between wind turbines and BoP facility) into the routine maintenance program
- Available inspection records for the BoP did not highlight any major concern, although substantial curtailment occurrences were observed (see next slide) which Arup deems addressable through sensitivity analyses in the financial model.

Figure 7.9. Diagram of windfarm BoP

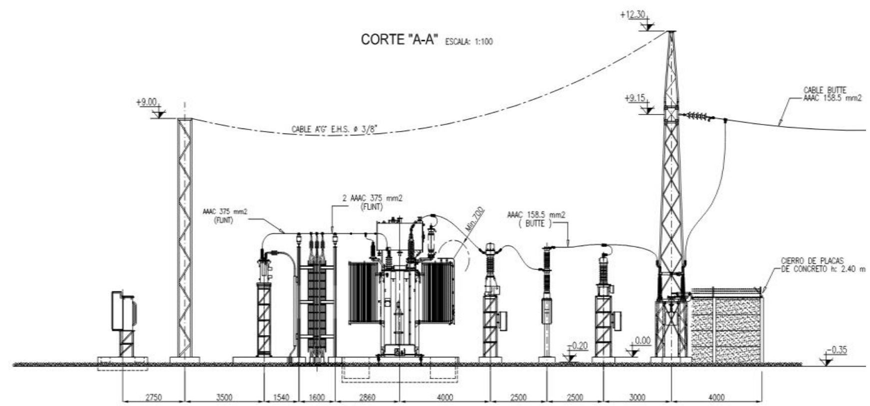


Figure 7.10. 23/66kV Substation Equipment Layout

Source: LAP | 0028-600-E-PL-1001-AB

7. Asset Condition: San Juan Design and Condition Overview

The 193.2 MW San Juan facility began commercial operations in early 2017. The project comprises 56 x V117-3.3 MW wind turbine generators (WTGs).

Overview of the San Juan facility

- San Juan is a 193.2 MW onshore windfarm, located in the III Region of Atacama, in the southern coastal area of the province of Vallenar, Chile.
- The key components of the Project comprise of:
  - 56 x V117-3.3 MW wind turbine generators (WTG), with a hub height of 91.5m, installed on shallow depth concrete gravity foundations (spread footings).
  - San Juan 33/220 kV substation (SJS) -collects the electricity generated by the turbines and increases the voltage for export to the transmission system. SJS is equipped with (2) 220/33 kV 80/110 MVA transformers and 31 x 1% +/-15% tap changers
  - Medium-voltage (MV) collection systems of twelve 33 kV circuits connect the WTGs to the substation.
  - The Project is connected to the Punta Colorada substation through an 83.6km, 220 kV, single circuit overhead line (OHL) with possibility to carry a second circuit.
  - WTGs are equipped with PowerBoost which uprates the WTGs from 3.30 MW to 3.45 MW each.
- The project already has developed a good operational track record since 2017, demonstrating above-required availability.
- The project utilizes reliable and proven technology - largely based on robust V117 technology from Vestas, who are also providing a full wrap O&M contract for the maintenance of the wind turbines.

Condition Summary and Life Extension

- Similar to Totoral, San Juan has experienced a number of technical issues since the start of operations. These have been mostly ramp-up issues that now appear to have been largely resolved. They are not anticipated to re-occur if the Company continues to follow the maintenance practices observed to date.

Figure 7.11. San Juan Situation Photo

Source: www.parquesanjuan.com/

- **WTGs:** Arup has not seen any indication that the core components of the WTGs and equipment's lifetime will not be able to operate beyond 30 years. WTGs appear to be properly maintained under the Vestas SMA contract. Arup recommends that Vestas conduct a Life Extension Program in the coming year in order to accurately assess the wear and tear on some of the main components (e.g. gearboxes).
- **Foundations:** Available inspection data for the towers and foundations, including recent 3-year inspections completed in 2019, did not highlight any major concerns. As with Totoral, a detailed fatigue study is recommended within a year to confirm the useful life of the foundations, along with more rigorous monitoring and inspections going forward.
- **BOP:** Available inspection data for the BoP did not highlight any major concerns (A transformer failure event appears to a cable arrangement and equipment issue but not an operating issue – see BOP section for San Juan for additional details).

7. Asset Condition: San Juan WTG Design (V117)

The V117 is built on the legacy of the V112-3.3 MW platform which was released in 2010 and has more than 5000 units installed globally. The V117 was first installed in H1 2016 and is rated IEC IIA.

The V117 Turbine Technical Specifications

- The table below summarizes the main technical specifications.
- The turbine utilizes a microprocessor pitch control system called OptiTip and the OptiSpeedTM (variable speed) feature. With these features, the wind turbine is able to operate the rotor at variable speed (rpm), helping to maintain the output at or near rated power.
- The WTG SCADA system is upgraded with PowerBoost and therefore uprated from 3.3 MW to 3.45 MW
- **Arup considers the V117 (V112) platform proven and does not consider the design to be an issue.**

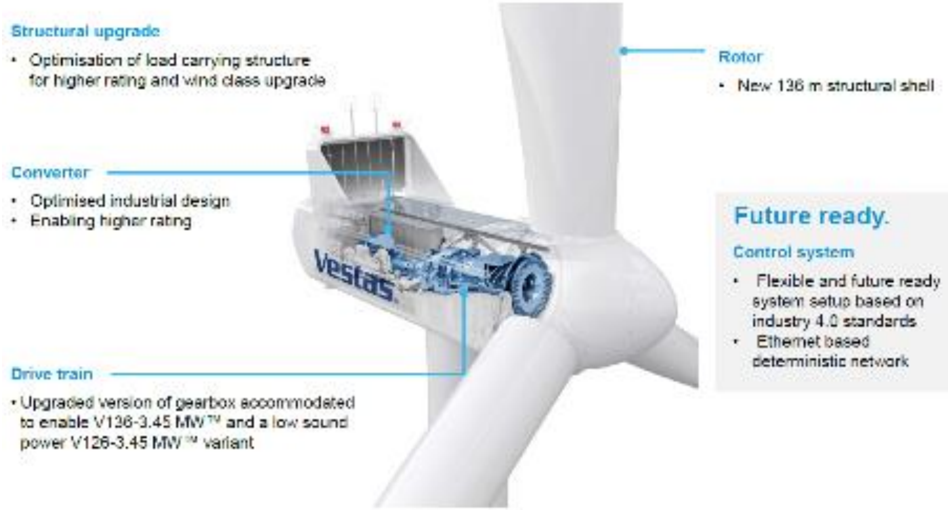
Table 7.2. Vestas V117-3.3 MW key technical specifications

Source: Vestas

Item	V117 3.3 MW IIA
Generator Type	Asynchronous with wound rotor (DIFG), slip rings and VCRS
Rated Power	3.3 MW / 3.45 MW (with power boost)
Converter	Full Scale Converter
Blade length	57.5 m
Gearbox	Planetary
Power regulation	Pitch regulated (OptiTip)
Hub height	91.5m
Cut-in wind speed Cut-out wind speed	3 m/s 25 m/s
Rated wind speed	12 m/s

Figure 7.12. Vestas V117 3.0 MW Side-View

Source: Vestas



7. Asset Condition – San Juan WTG Main Components

San Juan's WTG's have shown adequate performance. Other than one WTG transformer replacement, no other material issues or repairs have been identified since the beginning of operations.

Methodology

- In order to assess the conditions of the WTGs, Arup had access and reviewed the following sets of documentation :
  - Periodic (3-year) Inspection Reports that took place between September 2019 January 2020 (provided by LAP)
  - Monthly Operational Reports from 2017 to 2020 (provided by LAP)

Key Findings

- Based on discussions with Management and the maintenance information provided for review, we conclude that San Juan's WTGs have performed well since the beginning of operations. Other than the WTG 19's transformer replacement outlined below, no other material issues or repairs have been reported and the operational data does not suggest otherwise.

Turbine Transformers

- WTG 19 Transformer Failure. The transformer of WTG 19 which was manufactured in 2016, rated 33 kV and is located in the nacelle. No reason was provided for this transformer failure and Vestas simply requested it to be replaced.

7. Asset Condition – San Juan WTG Towers

Industry standard Vestas tubular-steel towers have been used, which have a certified life of at least 20 years. These are used internationally on many projects.

Towers – Design Review

- The WTGs and their supporting structures are designed to operate in a wind climate equivalent to IEC Class IIA in line with the IEC 61400-1 design standard. This classification is appropriate, in terms of structural loading, for the expected site conditions.
- The details of the tower design and the supporting calculations are proprietary information of Vestas and are not available for review. However, the nominal design life of the turbines and supporting structures is 20 years, which has been independently certified by DNV-GL.
- Vestas offer a life extension programme as part of their operation and maintenance service - i.e. if required beyond the original design life of 20 years. Vestas offer this service, typically after around 15-20 years of operation, and subject to detailed inspections, testing and assessment of the residual life of key components.
- Arup understands that Vestas have indicated that they would provide a life extension programme up to 30 years for their turbines which are owned by LAP. As part of the life extension programme Vestas would plan to complete a site-based fatigue assessment of the turbines up to the extended life. We understand this assessment has not yet been completed.
- We note that the extent of the OEM service from Vestas does not include the foundations; nor would Vestas normally take this risk.

Towers – Condition Assessment

- Available inspection data for the towers, including recent 3-year inspections completed in 2019, did not highlight any major concerns.

Figure 7.13. Image showing erection of towers

Source: LAP Monthly Report SJU May 2016

Figure 7.14. WTG 24 3-year inspection

Source: LAP Monthly Report SJU Dec 2019

7. Asset Condition – San Juan WTG Foundations

Gravity based concrete foundations are used for San Juan which is typical within the industry. The connection to the tower is formed by the commonly used 'Anchor Bolt' connection.

Foundations – Design Review

- The structural foundations of each wind turbine are a critical part of the overall structure, providing stability for the wind turbine generator, through the tower.
- The rotation of the wind turbine, and the varying stresses caused by the wind direction, gusting and turbulence, mean that the foundation structure receives significant cyclic loading and fatigue is a key consideration in the assessment of the useful life of the wind farm.
- The foundations were designed by Esteyco Chile, who are part of the global engineering consulting group Esteyco.
- WTGs are designed for a specific wind regime (e.g. Wind Class: IEC IIA). The turbine manufacture provides the resulting ultimate and fatigue loads acting on the foundation for use by the foundation designer.
- Typically, WTG foundations are fatigue-constrained in their design. That is, they are designed for a specified number of stress cycles over their lifetime, before there is naturally an increased risk of structural failure of the foundations as the foundations and WTG get older.
- The San Juan foundations are fabricated from cast-in-place reinforced concrete. They are circular shaped on plan with a diameter of 18.5m or 19m, depending on location.
- Connection to the tower is made via an anchor bolt connection.
- In the Anchor Bolt detail, the tower loads bear onto the top surface of the concrete foundations.
- An anchor ring (an annulus of steel plate) is cast into the foundation and post tensioned bolts connect the turbine tower to the anchor ring.

Figure 7.15. Plan view of foundation

Source: 4.1.5.2.2.1.1 P1417-DR-001_V05

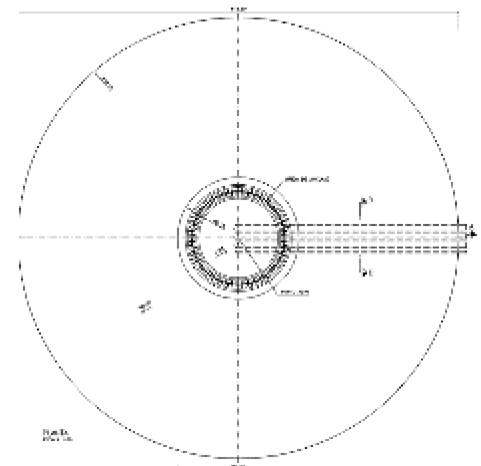
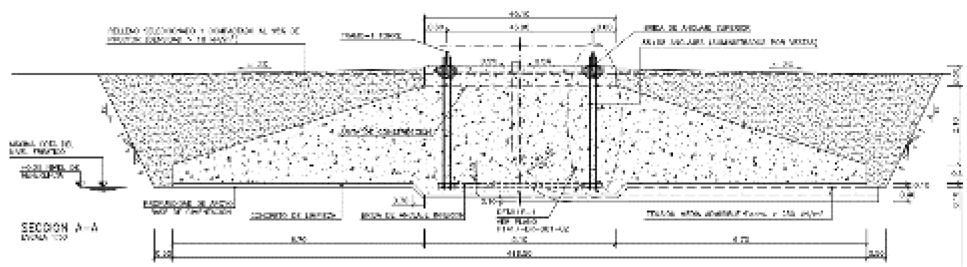


Figure 7.16. Elevation view of foundation

Source: 4.1.5.2.2.1.1 P1417-DR-001_V05



7. Asset Condition – San Juan WTG Foundations

Wind turbine foundations are subjected to complex, cyclic stress and strain loading induced by wind. A detailed life extension study is recommended, along with more rigorous monitoring and inspections.

Foundations – Design Review (Cont.)

- The foundations for the WTG are a very important component in the overall wind park. Should any problems arise during the operational phase, these can be expensive to rectify and can often be uneconomic to repair.
- On this basis, the validation of an appropriate design and satisfaction of construction quality are important – to ensure that a useful life of more than 20 years for the foundations can be validated.
- For San Juan, the design solution applied for the foundations are gravity foundations and the wind turbines are connected using an anchor bolt connection detail. This is an industry standard connection detail and is generally considered lower risk than the insert can detail used for Totoral, based on Arup's experience.
- Arup has not completed an in-depth design review of the foundation design or independent fatigue calculations as part of our scope of work. A high-level review of the design documentation provided by LAP indicates that the calculations completed generally follow industry standard practice; however, the fatigue assessment completed appears to be limited, based on our review and experience of similar wind farm foundations.
- An independent review of the foundations was completed in 2016 by a third-party consultant, which indicated the foundations were acceptable for 30 years of operation; however, the fatigue analysis presented in that report were limited.
- Arup recommends that LAP conduct a detailed assessment following industry-accepted standards such DNVGL-ST-C502 (the standard for reinforced fatigue design in the wind energy industry) to quantify the risk of fatigue damage, particularly if life extension of the asset beyond 20 years is desired.

Foundations – Condition Assessment

- From the maintenance documentation available, it is not evident that regular monitoring of the foundation beyond visual inspections is being completed – for example monitoring potential concrete cracking, backfill erosion, foundation settlement, and importantly, changes in tower verticality.
- In Arup’s view, it would be prudent to undertake more rigorous ongoing monitoring of the foundations over the coming years, in order to identify any deterioration in the foundations. This should include monitoring of tower verticality, regular concrete inspections, checking for signs of deterioration at the insert can interface and monitoring of backfill cover. Whilst preventative maintenance may be difficult due to lack of access to the reinforcement bars and rock anchors – rigorous monitoring will allow LAP to better asses the signs of fatigue and risks of foundation deterioration, and take corrective operating actions such as reducing turbine output, etc.

Figure 7.17. Inspections for tower connection to foundation

Source: LAP, WTG 22 December 2019

7. Asset Condition – San Juan BoP

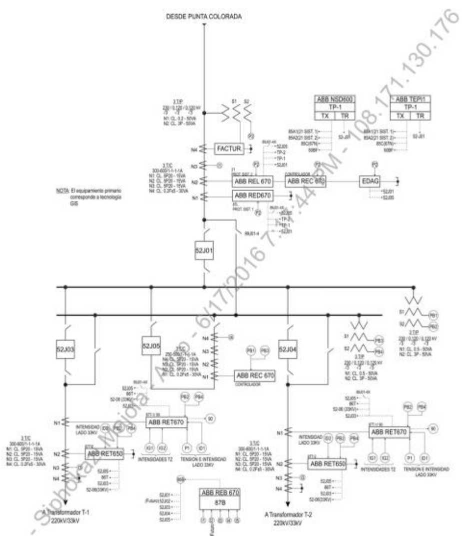
The San Juan windfarm has been operating well since 2017. Other than the Zig-Zag transformer failure in the summer of 2020, the remaining BoP components have not shown any material operational issues.

Overview of San Juan BoP facility

- The BoP was executed by Elecnor Chile which is a Spanish EPC contractor. The key BoP components of the Project included :
  - A single 33/220 kV windfarm substation - San Juan substation (SJS) - collects the electricity generated by the turbines and increases the voltage for export to the transmission system.
  - Two transformers on the San Juan substation, each of which is capable of delivering the 220 kV export voltage to effectively eliminate any risk of full power loss. Medium-voltage (MV) collection systems of twelve 33 kV circuits connect the WTGs to the substation.
  - Punta Colorada substation with an 83.6km, 220 kV, overhead line (OHL).

Figure 7.18. Line diagram of SJU BoP

Source: LAP



BoP – Condition Assessment

- The San Juan windfarm has been operating well since 2017. Other than the Zig-Zag transformer in the summer of 2020 described here, the BoP components have not shown any material operational issues.
- Arup is not aware of any grid compliance or recurring reliability issues that are worthy of note. Available inspection data for the BoP did not highlight any major concerns.
- Continuous performance monitoring, routine schedule maintenance, Inspection, condition monitoring, and testing are all used to detect deterioration of condition or degradation of performance of BoP.
- The documentation provided suggests that sufficient studies were undertaken to demonstrate its suitability for connection and 4 years of operation suggest that these have complied with the transmission operator requirements.
- LAP has confirmed that San Juan has complied with all regulatory requirements since the beginning of operations. Arup's review of the information provided highlights that the studies associated with the power quality requirements specified in NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO 2019 title 5.14 have not been completed. LAP has confirmed that these studies will be conducted in the near term.

7. Asset Condition – San Juan BoP

San Juan has been operating well since start of operations. A transformer failure in July 2020 caused a large outage, but this appears to be an isolated event, which should not reoccur.

Zig-Zag Transformer No. 2 failure event

- The San Juan Zig-Zag Transformer No. 2 failure event occurred on July 5, 2020 causing the unavailability of 50% of wind farm for 36 days.
- After a thorough inspection and a series of electrical tests, it was concluded the low insulation in the Zig Zag transformer No. 2 was the root cause. The failure event was primarily due to a combination of factors that developed prior to and during the failure, listed below in terms of significance and impact.
  - Poor transformer assembly practices.
  - Failures in the coordination of the protections.
  - Presence of harmonics in the network.
  - Unbalance of load in the phases, bad design of the medium voltage cable arrangement (Deterioration of the insulating material, partial discharges).
  - Failure in the application of operation protocols with load during coordination with the CEN
- In order to ensure the continued reliability of the substation and ensure that a similar failure does not happen again, Arup recommends the following:
  - Recheck the transformer assembly
  - Verify power quality in the medium voltage of the San Juan substation
  - Monitor the load balance in the 3 phases
  - Model the distribution of cables in the substation. Correct the distribution according to the modeling results
  - Establish a thermographic inspection plan for medium voltage connections that carried out by own personnel.
  - Conduct further study of protection
  - Add the adjustment of protection to the maintenance plans, if required.

Report Contents

8. Environmental, Health, and Safety

Based on the information reviewed, the projects appear to be well-managed from an EHS perspective and LAP management have good systems in place to monitor performance.

Introduction

- LAP has developed a robust EHS organization. The Company features a top-down organization; with managerial roles sitting at the LAP parent company level supported by dedicated EHS experts in each windfarm and transmission line
- Although the projects are situated in a relatively remote part of Chile, in Arup's view, the main potential environmental challenges for both assets are the following:
  - *Shadow flicker:* Shadow flicker is the effect of the sun (low on the horizon) shining through the rotating blades of a wind turbine, casting a moving shadow. It will be perceived as a "flicker" due to the rotating blades repeatedly casting a shadow.
  - *Impact on landscape*: Wind turbines generate a relevant impact over the landscape, due to their height and the blades.
  - *Noise:* Turbines also might cause noise impacts to nearby communities. This will depend much on the distance, and the study of the land use will play a relevant role to correctly minimize this impact.
  - *Impact to birds*: The operation of the wind farm may affect the flying paths of birds. A study on the matter should be conducted beforehand, and the operator will have to monitor the presence of birds in the area.

Management Systems and Certifications implemented

- LAP has valid certifications in ISO 9001:2015, ISO 14001:2015, and ISO 45001:2018 and has an Integrated Management System (IMS) which includes these three management areas, quality (ISO 9001), environment (ISO 14001) and occupational health and safety (ISO 45001), covering all Peruvian and Chilean assets, including the wind-assets under review.
- The IMS is supported by a general IMS policy, an IMS manual that remains based on OSHA 18001:2007 (in addition to ISO 45001:2018), and a group of company-specific documented procedures and protocols.
- HSE procedures provided for review include the Handling and Storage of Hazardous and Non-Hazardous Waste, Traveling and COVID-19 Protocols, as well as O&M procedures related to health, safety and environment

Figure 8.1. LAP's four management pillars

Source: LAP ESSH Presentation

Figure 8.2. ESSH monitoring schedule for SJU

Source: LAP ESSH Presentation

Proyecto	Actividad/mes	ID Compromiso	ene-20	feb-20	mar-20	abr-20	may-20	jun-20	jul-20	ago-20	sept-20	oct-20	nov-20	dic-20
SJU PE	Seguimiento Shadow Flicker	ID-225												
	Monitoreo Fauna (aves) - Parque	ID-143												
	Informe anual de aves (no ocurrencia de impactos)	ID-144												
	RETC - Declaración DS138	ID-171												
	RETC - Declaración Jurada	ID-171												
	Visitas Guiadas a Parque (anual)	ID-154												
	Monitoreo de calidad de efluentes Parque (anual)	ID-110												
	Escuelas de Verano para niños (anual)	ID-228												
Proyecto	Actividad/mes	ID Compromiso	ene-20	feb-20	mar-20	abr-20	may-20	jun-20	jul-20	ago-20	sept-20	oct-20	nov-20	dic-20
SJU LTE	Monitoreo Replante LTE - 2020 (anual)													
	Monitoreo Fauna (Aves) LTE													

8. Environmental, Health, and Safety

Based on the information reviewed, the projects appear to be well-managed from an EHS perspective and LAP management have good systems in place to monitor performance.

Environmental licensing

- Both wind farms, San Juan and Totoral, are in compliance with the applicable environmental framework. Both Assets were granted a *Declaración de Impacto Ambiental (DIA).* The project, transmission line, and substation received Resolutions of Environmental Qualification form the Environmental Service Commission of Atacama Region and the Environmental Service Executive Director.
- Some changes were undergone in the DIA of SJU in 2019 to allow for mitigation measures addressing the shadow flicking of four wind turbines.

Environmental obligations

- The environmental permitting and licensing framework sets several monitoring obligations for the operation stage:
  - Wind farm:
    - Follow-up of the shadow flicking
    - Presence of birds
    - Monitoring of other impacts
    - Wastewater discharge
  - Transmission Line:
    - Follow-up to revegetation
- On top of the abovementioned actions, LAP also arranges a Summer School on an annual basis in collaboration with the surrounding communities, to raise awareness on the environmental features of the Project and its liaison with the territory.
- The initial three year-period for the monitoring of birds and bats set by the environmental license is coming to an end and will therefore be reduced in frequency.
- The revegetation around the transmission line at SJU has been conducted covers an area of 2Ha.

Figure 8.3. LAP's ISO 9001 (2015), 14001 (2015), and 45001 (2018) certifications

Source: LAP ESSH Presentation

8. Environmental, Health, and Safety

Based on the information reviewed, the projects appear to be well-managed from an EHS perspective and LAP management have good systems in place to monitor performance.

EHS Performance

- LAP has provided evidence of internal auditing of their IMS; which is considered good practice. Evidence of compliance with external audits for the H&S system were also provided for review. Evidence of external audits for the ISO 9001:2015 and ISO 14001:2015 have not been provided for review.
- An external ISO 45001: 2018 audit performed in 2018 concluded that the system was still in the development process and for that reason could not be fully audited at that time. Arup concludes that LAP's current ISO 45001 management system **is in compliance**, as the latest certification was awarded less than 6 months ago in December 2020.
- LAP performed an internal IMS audit which covered all integrated management system processes for LAP Peru and Chile in August 2020, in which there were 12 total findings to be addressed. The most relevant EH&S findings were:
  - Gaps in the risk and opportunities management as well as management of hazards and environmental aspects due to insufficient establishment of corrective controls.
  - Gaps in management of emergency preparedness and response as well as employee competencies regarding the IMS.
- LAP has provided logs of their ongoing efforts to address these gaps, including efforts to integrate formal operations controls through all aspects of the Company's management and strategic planning.

Accident and Incident Data & Reporting

- Based on the accident data for the past 5 years (2016 – 2021) provided in the Accident Rate Assessment Reports there have been no occupational accidents or incidents during this time period.
- The documents provided show that official reporting of this accident data is done by the Chilean government/government agency (*Mutual de Seguridad*) who then performs an official accident data assessment in order to determine the additional contribution rate that the company will pay to Social Security. Arup concludes that LAP is following national regulation regarding accident data reporting.

COVID-19 Management

- LAP has created an overarching COVID-19 contingency management manual for all LAP Chile and Peru locations and also site-specific plan for the San and Totoral windfarms, laying out specific guidance for local requirements, site conditions, and operations.
- These are thorough plans that lay out protocols and recommendations related to the elimination of the risk of contagion, engineering adaptations, organizational actions, and administrative actions. Arup concludes that the COVID-19 response follows best practice.

Figure 8.4. Pictures of Safety Protocol Activities including COVID-19 Tests
Source: LAP ESSH Presentation (2020)

8. Environmental, Health, and Safety

Based on the information reviewed, the projects appear to be well-managed from an EHS perspective and LAP management have good systems in place to monitor performance.

Emergency Preparedness

- LAP has separate Emergency Plans established for the San Juan and the Totoral Wind Farms which detail staff responsibilities in the event of an emergency, establish different types of emergencies by origin (natural, technical/operational and social) and 3 levels of emergency and the procedures to follow for each level.
- Included appendices evidence the existence of an emergency action plan flowchart, an emergency contact information sheet, a map of meeting points and evacuation routes and an action plan for grave and fatal accidents.
- LAP has an established Emergency Committee which is responsible for understanding the emergency plan and the different levels as well as responsible for decision making in the event of an emergency and communication of information regarding emergencies to the press if necessary.

EHS Training

- LAP has a general training policy established for the company, though specific EHS considerations are not addressed. The policy addresses staff responsibilities related to training, specific and exceptional training policies and procedures related to training.
- The Training Policy evidences that an Annual Training Plan is established each September for the next year based on LAP's needs, priorities and the approved training budget for the respective year, although this specific document was not provided for review and therefore it's completeness in terms of EHS training cannot be determined at this time.

Social Performance

- The area where SJU is located features low population, and in the area of TOT population is nearly non-existent. Once the construction was finished, the relevance of the social impacts is therefore deemed to be low.
- SJU: LAP social team has arranged workshops in the past to understand how the Project would impact over the communities and keeps celebrating meetings in a regular basis to know how the Project development meets their expectations.
- TOT: In the case of TOT, LAP is not bound to social actions since the Projects is ruled under an older licensing framework than SJU. The social commitment is fully volunteer and includes an educational program.

Contractor Management

- LAP binds its contractors under a special procedure that includes several norms and actions. In Environment, contractors will have to meet the applicable regulations, be proactive in proposing enhancements and audit its own operations.
- In Health and Safety, contractors will have to meet the pertinent regulations as well, appoint an expert as H&S lead, set up the necessary plans and protocols to cater to the H&S of its staff, and adequately report to LAP.

Appendices

Appendix A: Yield Assessment Post-Construction Methodology

For San Juan and Totoral, Arup has completed yield assessments based on post-construction information in the form of SCADA data from the project turbines.

Post-Construction Methodology

- The industry standard post-construction yield methodology used by Arup is summarised below and in the flow chart opposite.
- SCADA data is obtained for the historical operational period covering 10-minute values of power and wind speed and a log of historical alarms or errors. The data is analysed to identify periods of performance which are not a feature of the underlying performance of the project and therefore the equivalent lost energy for each period is assessed.
- From this information, the generation for each month is corrected upwards to establish a gross generation, assuming a level of production at 100% availability and normal performance of the asset. This is the baseline for the yield forecast.
- Gross figures are then correlated against concurrent data from a reference wind speed source, in order to establish a relationship between the gross yield of the site and the Relative Windiness of the period, against a long-term average.
- This relationship is applied to the full historical period from the reference wind speed source to arrive at a long-term gross yield figure which would be achieved at 100% availability and normal performance over the long-term reference period.
- Secondary losses are assumed for factors such as availability, electrical efficiency, turbine performance and environmental factors. These losses are applied to the gross yield to arrive at a P50 net estimate of the yield. This is the value which has a 50% chance of being exceeded over the stated return period.
- An uncertainty assessment is carried out based on the specifics of data quality and strength of correlation, to arrive at P75, P90 yield estimates.
- The post-construction gross figure is inclusive of all wakes from within the project and from any neighbouring projects operational during the period. As such, uncertainties related to wind speed measurements, flow modelling and wake modelling are not present in this type of assessment and as such are normally considered to provide a more accurate view of project P50.

Figure A1. Post-Construction Yield Methodology

Source: Arup

Analysis of operational SCADA data

Correction of operational data to gross monthly yield values

Identification of appropriate long term wind speed reference dataset

Correlation between on-site data and reference dataset

Extrapolation of operational data to long term based on correlation

Secondary loss assumptions to obtain P50

Uncertainty analysis to arrive at P75 and P90

Appendix A: Yield Assessment Pre-Construction Methodology

For San Juan, Arup and UL have completed yield assessments based on pre-construction information in the form of meteorological masts installed on site.

Pre-Construction Methodology

- The industry standard pre-construction yield methodology used by Arup is summarised below and in the flow chart opposite.
- Wind data recorded on site is analysed to remove any periods of erroneous data and to correct for effects caused by interactions with the mast or other instruments installed.
- On-site measured wind speeds are generally only available for a relatively short term. Although they provide a good, local assessment of wind resource, they are not highly representative of the long-term expected wind resource. To correct for this, correlations are carried out between the wind speeds measured at the on-site masts and reference data from one or more long term wind speed sources. This information is then used to calibrate the on-site wind resource information against a long term expected wind resource.
- Where the mast height is different to the proposed hub height of the turbines on site, a shear adjustment is applied to extrapolate the wind distribution from the mast height to hub height at the mast location.
- To assess wind speeds across the site a flow model is used to extrapolate the wind speed horizontally to obtain wind speeds at each turbine location.
- These wind distributions are then applied to the turbine power curve to obtain gross yield figures at each turbine location.
- Wake modelling is performed to evaluate the interaction between turbines and the impact of this on the yield at each location. Where neighbouring wind farms will impact on yield, these are also considered in the modelling.
- Secondary losses are assumed for factors such as availability, electrical efficiency, turbine performance and environmental factors. These losses, combined with wake losses are applied to the gross yield to arrive at a P50 net estimate of the yield. This is the value which has a 50% chance of being exceeded over the stated return period.
- An uncertainty assessment is carried out based on the specifics of data quality, site complexity, consistency of long-term data and other factors to arrive at P75, P90 or other similar values.

Figure A2. Pre-Construction Yield Methodology

Source: Arup

Analysis of on-site measured wind data

Correlation between on-site data and reference dataset

Extrapolation of on-site data to long term based on correlation

Vertical extrapolation from mast height to turbine hub height

Horizontal extrapolation of wind speeds across site

Application of turbine power curve to calculate gross yield

Wake modelling to calculate array losses

Secondary loss assumptions to obtain P50

Uncertainty analysis to arrive at P75 and P90

Appendix B: Totoral Service and Availability Agreement

Topic	Description	Arup Commentary
Parties	Norvind S.A. Vestas Chile Turbinas Eólicas Limitada	
Term	Execution Date: April 1, 2013 The Term ends March 31, 2029.	• The term was extended in 2016 from the original Term of 10 Years from the Services Commencement Date, to 13 years. The 2016 addendum introduced a new Annual Base Fee structure that increases over time and placed a revenue requirement on incentive payments.

Fee	• The Annual Base Fee is as follows:
	  • 2016-2019: USD26,000 per WTG per year
	  • 2020-2024: USD42,500 per WTG per year
	  • 2025-2029: USD45,600 per WTG per year
	• Annual indexation is based on 65% material index referenced from the EUROSTAT: EU27 and 35% labor index referenced from Chilean Index of Consumer Prices
	• Delayed payment incurs a charge calculated at EURIBOR + 5%
	• The Annual Base Fee excludes VAT to be paid in Chilean Pesos
		• Arup opines the payment mechanism is in line with industry standards.
		• The annual base fee for Totoral is significantly lower, on a per-WTG basis, than for San Juan, which starts at USD63,000 per WTG per year.
		• The original Annual Base Fee agreed in 2013 was EUR36,600 annually, adjusted for inflation. The new fee structure increases over time. O&M costs for WTGs increase as they age and so an increase to the Annual Fee over time is reasonable.

Exclusions	Vestas's scope explicitly excludes:
	• The requirement to tighten bolts to defined levels when temperatures are below -20℃.
	• Operational constraints imposed by the buyer or by the utility operating grid
	• Excluded Events, which include
	  • The application of brakes on any WTG for 48 hours
	  • Dust storms, hail, ice and lightning
	  • Electromagnetic interference
	  • Strike (not limited to the contractor and its subs),
	  • Untwisting of cables,
	  • Force Majeure, which includes the closing of or congestion in any harbor, dock, port, canal or other adjunct of the shipping or navigation.	

Appendix B: Totoral Service and Availability Agreement

Topic	Description	Arup Commentary
Scope	• Vestas provides Operations Services, Scheduled Maintenance, Unscheduled Maintenance, consumables, spare parts, tools and equipment. • The scope includes WTGs “Tower to top”. • Vestas also provides 24/7 real-time monitoring, control and operation of the WTGs, including monitoring operational errors.	• Vestas is a market leader in turbine technology and installations and in Arup’s opinion they are the reasonable O&M provider for the equipment. • The Owner maintains responsibility for O&M of the foundations, BoP and providing staff facilities to Vestas. LAP also has a separate contract for security services. Arup opines this is consistent with industry norms. • LAP also maintains their own communications and monitoring team of five internal dispatchers to manage both wind farms and LAP’s other Chilean assets.
Availability Warranty	• Average Availability, assessed on a 12-month basis, is 97% for the duration of the term, enforceable by liquidated damages based on loss of revenue • The Availability Warranty went into effect April 1, 2016	• A 97% contractual availability obligation is typical. Average annual availability has exceeded this limit every year of operation. • LAP maintains resource risk and risk for power curve performance.
Availability Liquidated Damages	LDs are pro-rated according actual annual power output, the actual energy price received, and the delta between actual and warranted availability. They are calculated as follows: • (Warranted Average Availability / Measured Average Availability – 1) x (actual annual power output in kWh) x (average electricity price per kWh paid by the off-taker)	
Limits of Liability	• The maximum liability is equal to 50% of the total Service Fees payable throughout the term. • Liability following from gross negligence or willful misconduct are not capped. • Availability LDs are capped at the value of the Annual Base Fee for that production period (12 months)	• A liability cap of 50% of fees payable during term is in the low range of industry standards.
Incentive Payment	If Vestas exceeds its Availability Warranty, and the SPV has a total net revenue that exceeds an annual threshold of USD6.6m for 2016-2019, and USD7.7m for 2020-2029 (adjusted according to US CPI), an incentive payment is made. The amount of this payment is calculated using a similar formula as the LDs, reduced by 50%.	• Revenue thresholds were placed on the incentive payments as a part of the 2016 Addendum which also extended the term.

Appendix B: San Juan Service and Availability Agreement

Topic	Description	Arup Commentary
Parties	San Juan S.A. Vestas Chile Turbinas Eólicas Limitada	
Term	Execution Date: March 25, 2015 20 Years from the Availability Commencement Date, which occurred on March 2017.	• The term was extended to 20 years in 2021 at a fee structure that is lower than the original renewal value. Originally, the renewal value at the fifth year was USD94,000.

Fee	• The Annual Base Fee is as follows:
	  • Year 1-5: USD63,000 per WTG per year
	  • Year 6-10: USD64,900 per WTG per year
	  • Year 11-15: USD71,900 per WTG per year
	  • Year 16-20: USD82,900 per WTG per year
	• Annual indexation based on 65% material index referenced from the EUROSTAT: EU27 and 35% labor index referenced from Chilean Index of Consumer Prices
	• Delayed payment incur a charge calculated at EURIBOR + 5%
	• The Annual Base Fee excludes VAT to be paid in Chilean Pesos
		• Arup opines the payment mechanism is within industry standards.

Exclusions	Vestas's scope explicitly excludes:
	• Cleaning, resurfacing and/or painting of parts if cleaning is required due to dust, sand or other external factors unless this work is required as a direct result of a defect. The scope does include that after each scheduled or unscheduled maintenance event, Vestas must perform its best effort to clean any waster or dust.
	• Repair or replacement of parts due to cosmetic damage
	• Environmental remediation (unless caused by SP)
	• Repair/replacement of met masts
	• Waste management other than ordinary disposal of consumables
	• Excluded Events, which include
	  • The application of brakes on any WTG for 48 hours,
	  • Dust storms, hail, ice and lightning,
	  • Electromagnetic interference,
	  • Force Majeure.
		• Arup notes the explicit exclusion of any cosmetic or cleaning responsibilities from Vestas's scope. This responsibility for this risk remains with the Owner.

Appendix B: San Juan Service and Availability Agreement

Topic	Description	Arup Commentary
Scope	• Vestas Provide Operations Services, Scheduled Maintenance, Unscheduled Maintenance, consumables, spare parts, tools and equipment. • Scope includes WTGs "Tower to top", foundations are not included. • Vestas also provides 24/7 real-time monitoring, control and operation of the WTGs, including monitoring operational errors. • In 2016, there was an uprate of each WTG from 3.30MW to 3.45MW in exchange for a lump-sum fee of USD2,685,618.	• Vestas is a market leader in turbine technology and installations and in Arup's opinion they are the reasonable O&M provider for the equipment. • The Owner maintains responsibility for O&M of the foundations, BoP and providing staff facilities to Vestas. Arup opines this is consistent with industry norms. • A list of scheduled maintenance should also be established particular for parts that require exhaustive inspection
Reporting Requirements	• Monthly Performance Reports cover production, error codes, average availability calculations for the month, scheduled and unscheduled maintenance reports, detailed work descriptions, updates and upgrades to the WTGs. • Fault Analysis Reports on any diagnostic services on main components. • The Buyer has (15) days to review the Monthly Performance Report otherwise it is automatically deemed accepted by the Service Provider. The Buyer will have (30) days to review the Availability calculations to be provided by Vestas.	• Arup has reviewed Vestas's monthly performance reports for both SJU and Totoral. Unscheduled maintenance reports and fault analyses were also provided for review. See O&M section for further details.

Availability Warranty	• Average Availability, assessed on a rolling 12-month basis from COD:
	  • 95% - Year 1 of operations (assessed on a 12-month basis)
	  • 97% - Years 2-4 of operations (assessed on a 12-month basis)
	  • 98% - Remainder of term (assessed on a 24-month basis)
		• Arup notes the ramp of availability to 98% starting in Year 5 of operations (2021). Average annual availability has exceeded this limit every year of operation.
		• Arup recommends that the Buyer reviews the contractual language in order to remove ambiguity and that the Service Provider (Vestas)'s Measure Average Availability is not offset by external factors (Annex II, Article 6 b-4).

Availability Liquidated Damages	LDs are pro-rated according actual annual power output and the delta between actual and warranted availability. They are calculated as follows: • (Warranted Average Availability / Measured Average Availability – 1) x (Actual annual power output in kWh) x (USD111/MWh, adjusted according to US CPI)	• In contrast to the Totoral SAA, the energy price used to calculate both the LDs and incentive payments is fixed.
Limits of Liability	• The maximum liability is equal to the total Service Fees payable throughout the term. • Availability LDs are capped at USD3,752,000 for each production period.	• The maximum liability equal to the total service fees payable through the term is standard and considered best practice. • Arup recommends to obtain clarity on how major repairs (e.g. on Main Components) will be counted towards the maximum liability of the SMA.
Incentive Payment	• If Vestas exceeds its Availability Warranty, and the SPV has a total net revenue that exceeds a threshold of approximately USD62.4m (adjusted according to US CPI), an incentive payment is made. The amount of this payment is calculated using a similar formula as the LDs, reduced by 50%.	

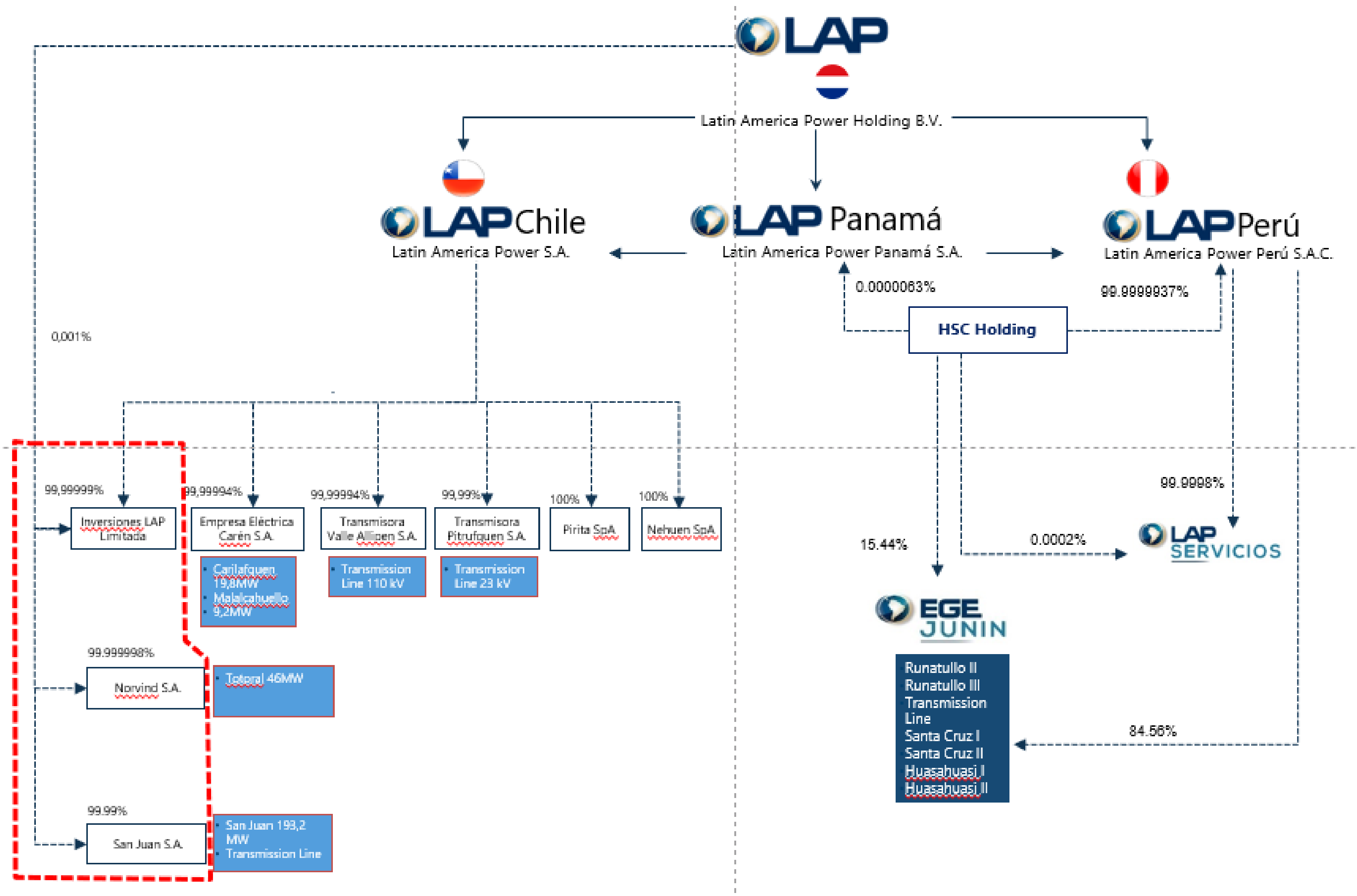
Appendix C: Power Purchase Agreements Summary

Client Type	Total PPAs	Term	Contract Beginning Year	Total Annual Generation (GWh)	PPA Award Price (USD/MWh)	Notes
TOTORAL	**38**			**179.4 (2021)**		
DisCos	23	15 years	2019	45.5	$113.22	1 Block with 23 DisCos
Non-Regulated	15	4-5 years	2018 - 2022	133.9	$43.00 - $54.20	
Walmart		*4 years + 8 months*	*2018*	*14.4*	*$50.50*	
Agricovial		*4 years + 8 months*	*2019*	*2.1*	*$53.50 (May – Aug, 2019)* *$50.00 (Sep. – Dec, 2019)* *$48.00 (2020 to 2023)*	
Ceresita		*4 years + 8 months*	*2019*	*5.5*	*$55.00 (May – Aug, 2019)* *$50.00 (Sep. – Dec, 2019)* *$49.00 (2020 to 2023)*	
Conitech		*4 years + 3 months*	*2019*	*3.0*	*$49.50*	
DoubleTree by Hilton		*4 years*	*2020*	*2.4*	*$49.5*	
PSA		*4 years*	*2020*	*0.9*	*$42.00*	
MN Agricola Ltda		*4 years*	*2020*	*2.7*	*$42.80*	
Inversiones Punta Blanca		*4 years*	*2021*	*0.8*	*$43.00*	
Viñedos Familia Chadwick		*4 years*	*2021*	*3.6*	*$45.00*	
Minera Cerro Negro		*4 years*	*2021*	*40*	*$42.13*	
Universidad de Los Andes		*4 years*	*2022*	*16*	*$40.00*	
Boulevard Maipu		*4 years*	*2021*	*3*	*$42.00*	
ICB		*2 years*	*2021*	*3*		
Chacayes		*3 years*	*2019*	*35*		
Vina Caliterra		*4 years*	*2021*	*1.5*		

Appendix C: Power Purchase Agreements Summary

Client Type	Total PPAs	Term	Contract Beginning Year	Total Annual Generation (GWh)	PPA Award Price (USD/MWh)	Notes
SAN JUAN	**70**			**641.3 GWh (2021)**		
DisCos	67	15 years	2017 - 2018	381.5	$100.65-103.22	3 blocks with 22 DisCos each (plus *Enel has 1 contract for 3 blocks*)
Metro	1	16 years	2016	59.8	$95.00	Generation is variable. Average of 67 GWh
Non-Regulated	2	4 + years	2019 - 2021	200.0	$41.00- $48.00	
Enel		*4 years + 4 months*	*2019*	*45 (2019)* *150 (2020)* *180 (2021-3)*	*$52.50 (2019)* *$49.50 (2020)* *$48.00 (2021)* *$47.00 (2022-3)*	
Cinergia		*4 years*	*2021*	*20 (2021)*	*$41.00*	

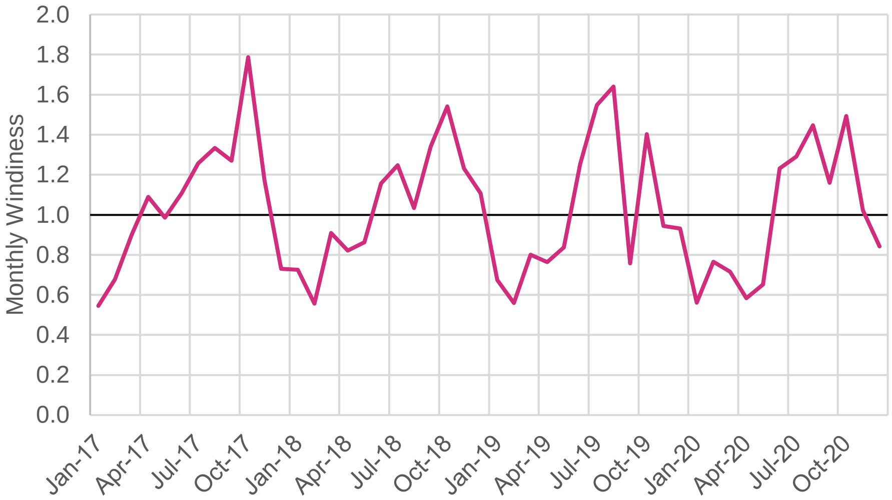
Appendix D: LAP Corporate Structure

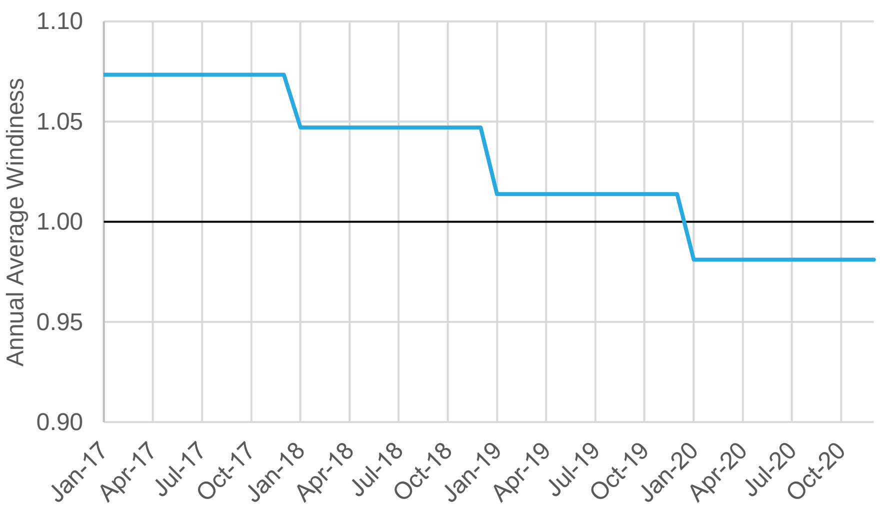


Appendix E: Windiness Index

San Juan: Monthly and Annual Windiness Index

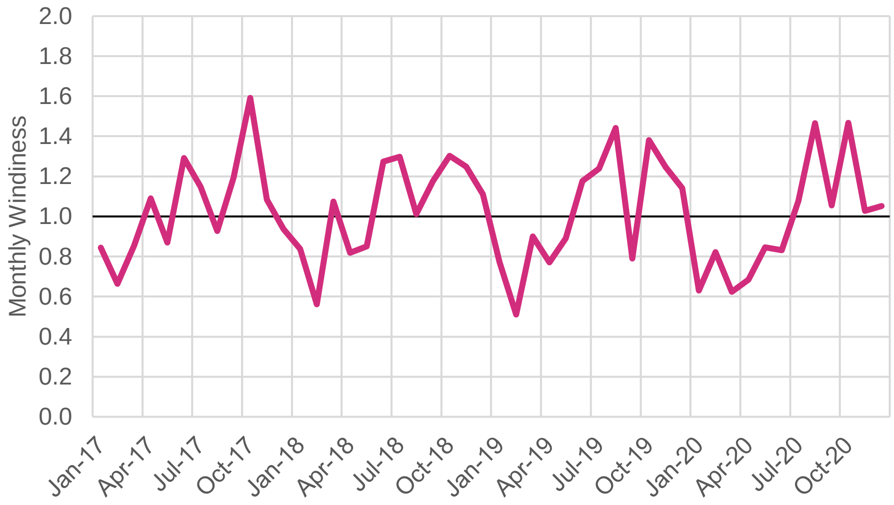
Source: Arup Analysis (EMD-WRF data)

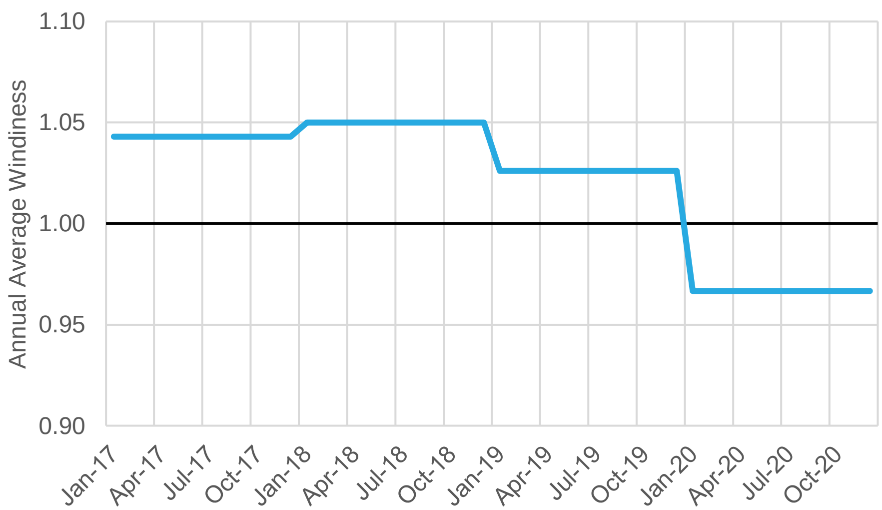




Totoral: Monthly and Annual Windiness Index

Source: Arup Analysis (EMD-WRF data)





Appendix F: Financial Model Review

Technical Inputs to Model

- Arup has reviewed the technical inputs to the financial model for the O&M cost and can confirm these are reasonably consistent with the values provided to Arup during the time of our review
- Arup has not validated the inputs, the functionality or the outputs of the model and understands that ILAP engaged others to review and audit the functionality and structure of the financial model

Financial Model Parameters

Arup has conducted a review of the following materials inputs to the Concessionaire's financial model and found that:

- The financial model accurately reflects the cost and terms of the Vestas Contract
- The financial model accurately reflects the expected operations and maintenance costs to be incurred by ILAP throughout the remaining useful life of the assets
- The financial model accurately reflects the Net Yield values for San Juan and Totoral provided in the report herein

Furthermore, Arup has been informed that the model reflects the following assumptions:

- Energy marginal cost and capacity payment projections modeled in accordance with the projections developed by Valgesta
- Chile expected inflation in 2021 of 3.4%, and long-term inflation target of 3.1%
- U.S. expected inflation in 2021 of 2.8$, and long-term inflation target of 2.2%

Sources and Uses

Sources	$mm	%
New Debt	$ 403.9	100.0 %
Total Sources	**$ 403.9**	**100.0 %**

Uses	$mm	%
Refi Totoral Debt	$ 47.2	11.7 %
Refi San Juan Debt	$ 342.0	84.7 %
Refi Prem. (0.75%)	$ 2.9	0.7 %
Stamp Tax	$ 3.2	0.8 %
LC fees	$ 0.5	0.1 %
Fees & Expenses	$ 8.0	2.0 %
Total Sources	**$ 403.9**	**100.0 %**

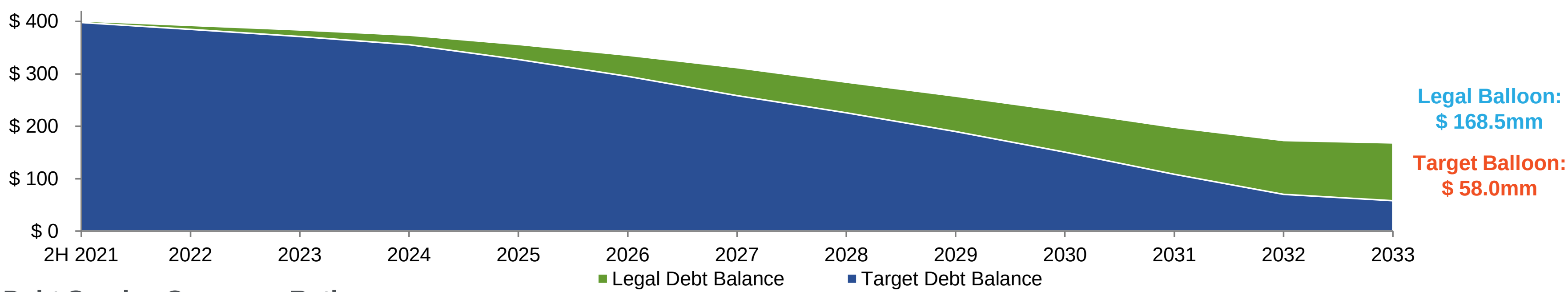
Appendix F: Financial Model Review

P50 Base Case Financial Model

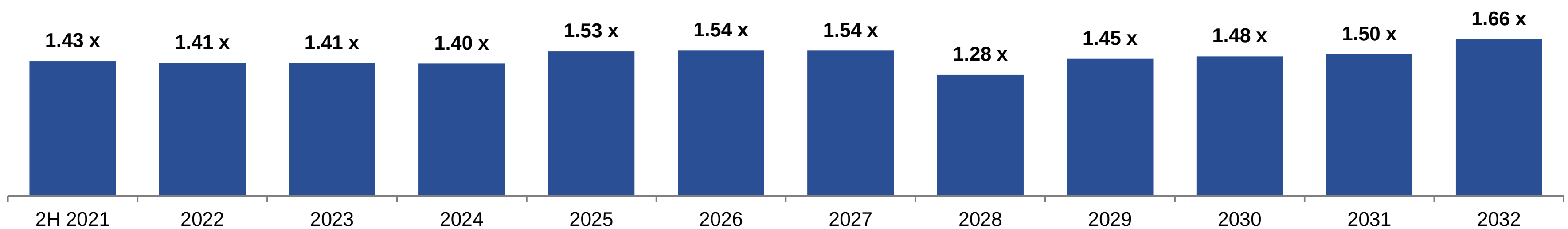
- In the Base Case Financial Model provided by ILAP, ILAP states that the model assumes:
  - P50 generation of 552.1 GW/h for San Juan, and 81.4 GW/h for Totoral, in line with the present report
  - 97.0% availability for both assets, in line with the Vestas' contract guaranteed availability
  - Valgesta's energy marginal cost and capacity payment projections are materialized
  - No OpEx overruns

The figures below highlight some of the key outputs from the Base Case Financial Model:

Debt Amortization Profile



Debt Service Coverage Ratio



Appendix F: Financial Model Review

P50 Base Case Financial Model Outputs

	2H 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Contracted Revenues	$ 25,506	$ 53,787	$ 56,743	$ 52,336	$ 62,721	$ 64,356	$ 65,593	$ 67,036	$ 68,511	$ 70,018	$ 71,559	$ 49,632	$ 8,109	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Capacity Revenues	1,798	3,658	3,738	3,820	3,904	3,990	4,078	4,168	4,259	4,353	4,449	4,547	4,647	4,749	4,853	4,960	5,069	5,181	5,295	5,411
Spot Revenues	768	(387)	(3,161)	2,419	(1,345)	1,257	1,781	5,299	8,445	9,363	9,633	20,906	41,418	46,979	47,964	47,648	48,198	49,736	50,310	51,489
Pass-Through Revenues	5,693	12,222	12,749	7,971	8,887	8,522	8,661	8,865	9,075	9,289	9,508	6,496	884	-	-	-	-	-	-	-
Total Revenues	**$ 33,765**	**$ 69,280**	**$ 70,069**	**$ 66,547**	**$ 74,167**	**$ 78,125**	**$ 80,113**	**$ 85,368**	**$ 90,290**	**$ 93,023**	**$ 95,149**	**$ 81,580**	**$ 55,057**	**$ 51,728**	**$ 52,817**	**$ 52,608**	**$ 53,268**	**$ 54,916**	**$ 55,605**	**$ 56,900**
Opex	(13,355)	(27,385)	(27,827)	(22,749)	(24,511)	(23,976)	(24,339)	(24,919)	(25,563)	(26,125)	(26,103)	(23,626)	(15,561)	(14,841)	(15,228)	(15,575)	(15,964)	(16,399)	(16,805)	(17,247)
EBITDA	**$ 20,411**	**$ 41,895**	**$ 42,242**	**$ 43,797**	**$ 49,656**	**$ 54,149**	**$ 55,775**	**$ 60,449**	**$ 64,727**	**$ 66,898**	**$ 69,046**	**$ 57,954**	**$ 39,496**	**$ 36,887**	**$ 37,589**	**$ 37,033**	**$ 37,303**	**$ 38,517**	**$ 38,800**	**$ 39,652**
D&A	(10,158)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(18,826)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(7,021)	-
EBIT	10,253	21,580	21,927	23,482	29,341	33,834	35,459	40,134	44,412	48,072	55,003	43,911	25,454	22,844	23,547	22,990	23,261	24,474	31,779	39,652
Taxes	-	-	-	-	-	-	(999)	(7,341)	(8,824)	(9,822)	(10,792)	(8,266)	(4,114)	(5,046)	(5,241)	(5,120)	(5,202)	(5,518)	(8,253)	(9,856)
NOPAT	**$ 10,253**	**$ 21,580**	**$ 21,927**	**$ 23,482**	**$ 29,341**	**$ 33,834**	**$ 34,460**	**$ 32,792**	**$ 35,587**	**$ 38,250**	**$ 44,211**	**$ 35,645**	**$ 21,339**	**$ 17,798**	**$ 18,306**	**$ 17,870**	**$ 18,058**	**$ 18,957**	**$ 23,526**	**$ 29,797**
D&A	10,158	20,315	20,315	20,315	20,315	20,315	20,315	20,315	20,315	18,826	14,043	14,043	14,043	14,043	14,043	14,043	14,043	14,043	7,021	-
Change in Working Capital	85	256	(118)	(1,561)	630	(1,114)	66	(162)	(52)	156	(225)	1,265	(1,739)	59	42	327	(78)	225	128	127
Change in PEC Receivables	(771)	(1,103)	(1,473)	-	5,247	5,247	5,247	-	-	-	-	-	-	-	-	-	-	-	-	-
CapEx	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CFADS	**19,724**	**41,048**	**40,652**	**42,237**	**55,533**	**58,282**	**60,089**	**52,946**	**55,850**	**57,231**	**58,029**	**50,953**	**33,643**	**31,900**	**32,391**	**32,239**	**32,023**	**33,224**	**30,676**	**29,924**
Debt Schedules																				
BoP Balance	403,898	398,233	384,998	371,415	355,686	327,394	295,124	258,553	226,025	190,007	150,733	108,575	70,261	-	-	-	-	-	-	-
Legal Amortization	(3,073)	(8,161)	(8,559)	(10,489)	(17,606)	(20,645)	(23,575)	(27,649)	(26,537)	(28,750)	(30,798)	(24,997)	(4,515)	-	-	-	-	-	-	-
Target Amortization	(2,593)	(5,073)	(5,025)	(5,239)	(10,686)	(11,626)	(12,995)	(4,879)	(9,481)	(10,524)	(11,360)	(13,317)	(7,772)	-	-	-	-	-	-	-
Balloon	-	-	-	-	-	-	-	-	-	-	-	-	(57,974)	-	-	-	-	-	-	-
EoP Balance	**$ 398,233**	**$ 384,998**	**$ 371,415**	**$ 355,686**	**$ 327,394**	**$ 295,124**	**$ 258,553**	**$ 226,025**	**$ 190,007**	**$ 150,733**	**$ 108,575**	**$ 70,261**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interest Expense	(10,518)	(20,557)	(19,909)	(19,180)	(18,195)	(16,672)	(14,927)	(13,073)	(11,328)	(9,408)	(7,329)	(5,172)	(1,830)	-	-	-	-	-	-	-
LC Fees	(224)	(447)	(447)	(462)	(514)	(557)	(565)	(590)	(582)	(556)	(562)	(529)	(247)	-	-	-	-	-	-	-
Key Credit Metrics																				
Target Balloon	$ 57,974																			
Legal Balloon	$ 168,544																			
Average DSCR	1.75 x																			
Min. DSCR	1.28 x																			
EoP Debt Balance	$ 398,233	$ 384,998	$ 371,415	$ 355,686	$ 327,394	$ 295,124	$ 258,553	$ 226,025	$ 190,007	$ 150,733	$ 108,575	$ 70,261	-	-	-	-	-	-	-	-
Debt $ / kW	$ 1,665	$ 1,610	$ 1,553	$ 1,487	$ 1,369	$ 1,234	$ 1,081	$ 945	$ 794	$ 630	$ 454	$ 294	-	-	-	-	-	-	-	-
Legal DSCR	1.43 x	1.41 x	1.41 x	1.40 x	1.53 x	1.54 x	1.54 x	1.28 x	1.45 x	1.48 x	1.50 x	1.66 x	5.10 x	-	-	-	-	-	-	-
Target DSCR	1.20 x	1.20 x	1.20 x	1.19 x	1.18 x	1.18 x	1.15 x	1.15 x	1.17 x	1.16 x	1.16 x	1.16 x	2.34 x	-	-	-	-	-	-	-
% Original Outstanding	98.6 %	95.3 %	92.0 %	88.1 %	81.1 %	73.1 %	64.0 %	56.0 %	47.0 %	37.3 %	26.9 %	17.4 %	-	-	-	-	-	-	-	-

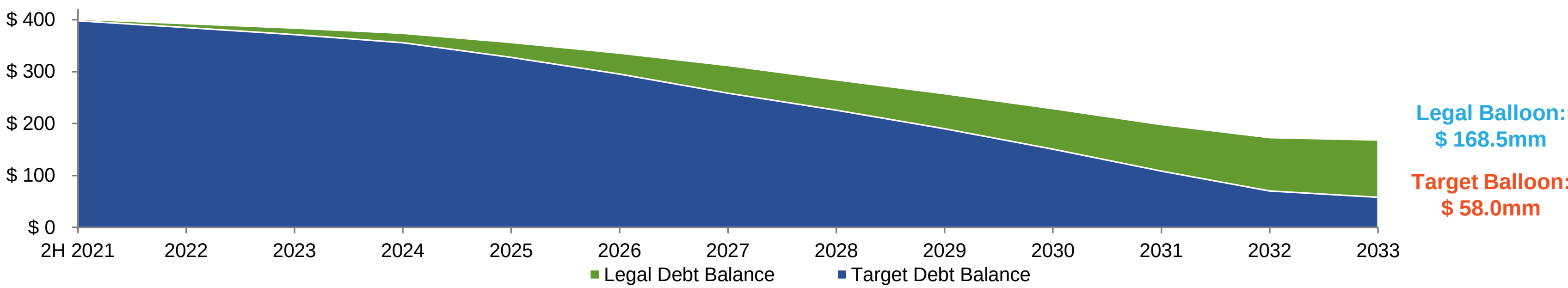
Appendix F: Financial Model Review

P90 Base Case Financial Model

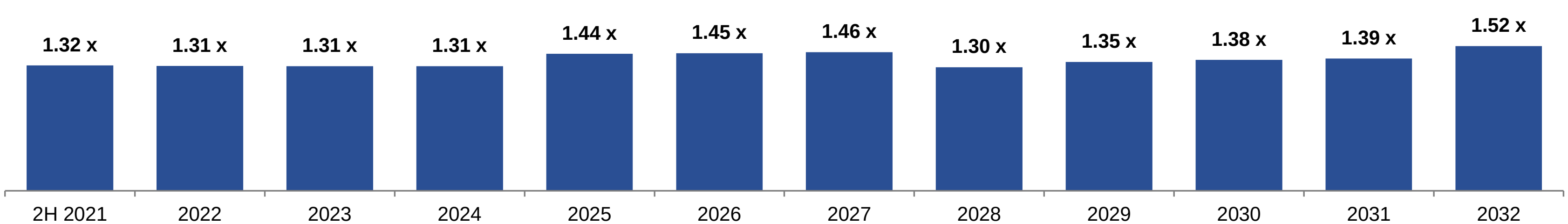
- In the Base Case Financial Model provided by ILAP, ILAP states that the model assumes:
  - 1-year P90 generation of 478.6 GW/h for San Juan, and 70.7 GW/h for Totoral, in line with the present report
  - 97.0% availability for both assets, in line with the Vestas' contract guaranteed availability
  - Valgesta's energy marginal cost and capacity payment projections are materialized
  - No OpEx overruns

The figures below highlight some of the key outputs from the Downside Case Financial Model:

Debt Amortization Profile



Debt Service Coverage Ratio



Appendix F: Financial Model Review

P90 Base Case Financial Model Outputs

	2H 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Contracted Revenues	$ 25,506	$ 53,787	$ 56,743	$ 52,336	$ 62,721	$ 64,356	$ 65,593	$ 67,036	$ 68,511	$ 70,018	$ 71,559	$ 49,632	$ 8,109	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Capacity Revenues	1,798	3,658	3,738	3,820	3,904	3,990	4,078	4,168	4,259	4,353	4,449	4,547	4,647	4,749	4,853	4,960	5,069	5,181	5,295	5,411
Spot Revenues	(970)	(3,414)	(6,311)	(826)	(4,855)	(2,531)	(2,585)	293	3,154	3,880	3,817	15,072	35,460	40,735	41,588	41,315	41,792	43,125	43,623	44,645
Pass-Through Revenues	5,693	12,222	12,749	7,971	8,887	8,522	8,661	8,865	9,075	9,289	9,508	6,496	884	-	-	-	-	-	-	-
Total Revenues	**$ 32,027**	**$ 66,253**	**$ 66,919**	**$ 63,302**	**$ 70,657**	**$ 74,336**	**$ 75,747**	**$ 80,362**	**$ 84,999**	**$ 87,541**	**$ 89,333**	**$ 75,747**	**$ 49,099**	**$ 45,484**	**$ 46,442**	**$ 46,275**	**$ 46,861**	**$ 48,306**	**$ 48,918**	**$ 50,056**
Opex	(13,147)	(27,006)	(27,453)	(22,399)	(24,192)	(23,657)	(24,020)	(24,592)	(25,233)	(25,798)	(25,832)	(23,366)	(15,297)	(14,566)	(14,946)	(15,294)	(15,679)	(16,106)	(16,508)	(16,943)
EBITDA	**$ 18,879**	**$ 39,247**	**$ 39,467**	**$ 40,903**	**$ 46,466**	**$ 50,679**	**$ 51,727**	**$ 55,770**	**$ 59,766**	**$ 61,743**	**$ 63,501**	**$ 52,381**	**$ 33,802**	**$ 30,918**	**$ 31,495**	**$ 30,981**	**$ 31,182**	**$ 32,200**	**$ 32,411**	**$ 33,113**
D&A	(10,158)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(20,315)	(18,826)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(14,043)	(7,021)	-
EBIT	8,722	18,932	19,151	20,588	26,150	30,364	31,412	35,454	39,451	42,917	49,458	38,338	19,760	16,875	17,453	16,938	17,139	18,157	25,389	33,113
Taxes	-	-	-	-	-	-	-	(2,053)	(7,662)	(8,613)	(9,491)	(6,959)	(2,777)	(3,645)	(3,808)	(3,700)	(3,761)	(4,030)	(6,752)	(8,319)
NOPAT	**$ 8,722**	**$ 18,932**	**$ 19,151**	**$ 20,588**	**$ 26,150**	**$ 30,364**	**$ 31,412**	**$ 33,401**	**$ 31,789**	**$ 34,304**	**$ 39,967**	**$ 31,379**	**$ 16,983**	**$ 13,230**	**$ 13,644**	**$ 13,238**	**$ 13,378**	**$ 14,127**	**$ 18,638**	**$ 24,794**
D&A	10,158	20,315	20,315	20,315	20,315	20,315	20,315	20,315	20,315	18,826	14,043	14,043	14,043	14,043	14,043	14,043	14,043	14,043	7,021	-
Change in Working Capital	91	132	(88)	(1,447)	637	(1,094)	29	(37)	(24)	150	(185)	1,268	(1,742)	65	52	299	(52)	211	128	127
Change in PEC Receivables	(771)	(1,103)	(1,473)	-	5,247	5,247	5,247	-	-	-	-	-	-	-	-	-	-	-	-	-
CapEx	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CFADS	**18,199**	**38,276**	**37,906**	**39,456**	**52,350**	**54,832**	**57,004**	**53,679**	**52,080**	**53,280**	**53,825**	**46,690**	**29,284**	**27,338**	**27,739**	**27,580**	**27,369**	**28,381**	**25,787**	**24,922**
Debt Schedules																				
BoP Balance	403,898	398,233	384,998	371,415	355,686	327,394	295,124	258,553	226,025	190,007	150,733	108,575	70,261	-	-	-	-	-	-	-
Legal Amortization	(3,073)	(8,161)	(8,559)	(10,489)	(17,606)	(20,645)	(23,575)	(27,649)	(26,537)	(28,750)	(30,798)	(24,997)	(4,515)	-	-	-	-	-	-	-
Target Amortization	(2,593)	(5,073)	(5,025)	(5,239)	(10,686)	(11,626)	(12,995)	(4,879)	(9,481)	(10,524)	(11,360)	(13,317)	(7,772)	-	-	-	-	-	-	-
Balloon	-	-	-	-	-	-	-	-	-	-	-	-	(57,974)	-	-	-	-	-	-	-
EoP Balance	**$ 398,233**	**$ 384,998**	**$ 371,415**	**$ 355,686**	**$ 327,394**	**$ 295,124**	**$ 258,553**	**$ 226,025**	**$ 190,007**	**$ 150,733**	**$ 108,575**	**$ 70,261**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interest Expense	(10,518)	(20,557)	(19,909)	(19,180)	(18,195)	(16,672)	(14,927)	(13,073)	(11,328)	(9,408)	(7,329)	(5,172)	(1,830)	-	-	-	-	-	-	-
LC Fees	(224)	(447)	(447)	(462)	(514)	(557)	(565)	(590)	(582)	(556)	(562)	(529)	(247)	-	-	-	-	-	-	-
Key Credit Metrics																				
Target Balloon	$ 57,974																			
Legal Balloon	$ 168,544																			
Average DSCR	1.61 x																			
Min. DSCR	1.30 x																			
EoP Debt Balance	$ 398,233	$ 384,998	$ 371,415	$ 355,686	$ 327,394	$ 295,124	$ 258,553	$ 226,025	$ 190,007	$ 150,733	$ 108,575	$ 70,261	-	-	-	-	-	-	-	-
Debt $ / kW	$ 1,665	$ 1,610	$ 1,553	$ 1,487	$ 1,369	$ 1,234	$ 1,081	$ 945	$ 794	$ 630	$ 454	$ 294	-	-	-	-	-	-	-	-
Legal DSCR	1.32 x	1.31 x	1.31 x	1.31 x	1.44 x	1.45 x	1.46 x	1.30 x	1.35 x	1.38 x	1.39 x	1.52 x	4.44 x	-	-	-	-	-	-	-
Target DSCR	1.11 x	1.12 x	1.12 x	1.12 x	1.11 x	1.11 x	1.09 x	1.16 x	1.09 x	1.08 x	1.08 x	1.06 x	2.04 x	-	-	-	-	-	-	-
% Original Outstanding	98.6 %	95.3 %	92.0 %	88.1 %	81.1 %	73.1 %	64.0 %	56.0 %	47.0 %	37.3 %	26.9 %	17.4 %	-	-	-	-	-	-	-	-

Appendix G: Arup Engagement Letter

ARUP

Your ref
Our ref 281355-00
File ref 30-3-01

ARUP

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May 14, 2021

Dear Sirs,

ILAP Onshore Wind Farms Refinancing
Letter of Engagement

We are writing to confirm the basis of the appointment of Arup Latin America S.A ("Arup") by Inversiones Latin American Power Limitada (the "Client") dated May 14 2021 (the "Appointment") to provide technical and environmental due diligence services in connection with the refinancing of the ILAP onshore wind farms in the Chilean Atacama region (the "Project" or the "Transaction").

Scope of Services

1. Our scope of services and the nature of the report we are to provide are set out in Appendix 1 (the "Services"). Attention is drawn to the limitations in the Services.

2. Following completion of our Services we shall report formally in writing to summarize our findings in one or more reports as set out in this Engagement Letter ('Reporting') (the "Report"). Our Report may be included in any offering memorandum, private placement memorandum, confidential information memorandum, rating agency presentation, investor presentation, prospectus or other disclosure document (a "Disclosure Document") that is distributed to investors or financial institutions relating to the Transaction, subject to the conditions later in this Letter of Engagement (Circulation of our Report).

Fees

3. Our fees will be set out in a separate Fee Letter. In the event that we incur additional costs due to any changes in the scope of our work, delays in the provision of information or delays in the timetable, we will notify you and discuss with you the implication for our fee.

Timetable

4. We propose to issue a Draft Due Diligence Report within three (3) weeks of receiving quality information from the client as outlined in the Request of Information included at the end of Appendix 1. We propose to issue a Final Due Diligence report within one (1) week of receiving the Client and the financing parties feedback.

Communication

5. The core team will comprise members of our Transaction Advice Team who will draw on specific sector expertise as required.

6. Jonathan Yates will lead our team. He will be the Project Director responsible for day-to-day service delivery. He has over 25 years of relevant deal experience. Other key team members include:

   - Jorge Macedo (Project Manager)
   - Rebecca Green (Deputy Project Manager)
   - Martin Tremblay (Technical Lead)
   - Edmund Andrew (Commercial Lead)

7. Within one week of appointment, Client shall nominate a single point of contact to act as the coordinator for the Arup services.

Reporting

8. Prior to completion of the Services, we may supply written advice, issue a draft report and/or make oral presentations. Our final Report shall take precedence over all such prior communications. No reliance shall be taken by you or any other party on any draft or interim advice or interim presentation without our prior written consent. Where you wish to rely on oral advice or an oral presentation, you shall inform us and we shall supply documentary evidence of the advice concerned.

9. We confirm that we are able to provide reliance to any initial purchasers, lenders, advisors and investors (the “Recipients”) upon execution of a Reliance Letter, substantially in the form attached hereto as Appendix 4., and that to the extent the Transaction is executed in bond format, we consent to the inclusion of our Report or any summary thereof (including use of our name) in any Disclosure Documents

10. Our Report will be accompanied with the notice set out in Article 11 of our Terms and Conditions.

11. In the technical due diligence investigation, we will be relying on information provided by third parties. We do not accept responsibility for the information provided by you or any third party. We will satisfy ourselves as far as is possible that the information presented in our Report is consistent with other information

made available to us. We will not, however, seek to establish the reliability of the sources by reference to other evidence. We will draw to your attention any significant limitations in the information made available to us. We will indicate within our Report the sources of the information presented. Where we agree to undertake review procedures as part of our Services these will be stated in our Report.

12. We may present or review prospective financial information in performing our Services. Such prospective financial information will be derived from information provided by you or others; we do not accept responsibility for such information. We emphasize that the realization of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. We accept no responsibility for the realization of the prospective financial information; actual results are likely to be different from those shown in the prospective financial information because events and circumstances frequently do not occur as expected, and the differences may be material.

13. We will not be under any obligation to (and will not) perform any work, take account of, or comment on any events occurring after the issue of our Report in final form to the addressees of this letter.

14. You should note that the findings of our Report and any draft version will not constitute recommendations as to whether you should proceed with the Transaction.

Circulation of our Report

15. Save as provided in this Appointment, you shall not in any circumstances provide to third parties any version of our Report, deliverables or information, or any element thereof, prepared in connection with this Appointment, unless you have received our prior written consent. If we give our consent, such consent is subject to the relevant third party and us either entering into a release letter in the form set out in Appendix 3 or a reliance letter in the form set out in Appendix 4.

16. You shall not in any circumstance remove the contents of the notice set out in Clause 11 of Appendix 2 from our Report when circulating the Report pursuant to the terms of this Appointment.

17. Client confirms that any financing arrangements for the Transaction will not include Retail Investors and Retail Investors are not entitled to rely on the Report or any Deliverables. Arup explicitly does not permit circulation of or reliance upon any Deliverables to/by Retail Investors and will not accept any extension of responsibility and/or liability to Retail Investors.

Other consortium members and Newco

18. We understand that at any point in the future another entity or entities may join you to form a consortium (the "Consortium"). Upon joining the Consortium, you

shall procure that such additional entity or entities shall be added to this Appointment by signing the counterpart of the Engagement Letter and will be our joint client along with you and shall be deemed as such as if they had been from the effective date of this Appointment. Thereafter, any reference to "you" in this Appointment shall include the additional entity or entities forming the Consortium. If other entities are added to this Appointment, each entity shall be jointly and severally responsible for your obligations hereunder.

19. We understand that you (or if formed, the Consortium) may form a new entity as a vehicle to deliver the Project ("Newco"). Upon the establishment or incorporation of Newco, you shall procure that Newco shall be added to this Appointment and by signing the counterpart of the Engagement Letter, Newco will be our joint client along with you (or if formed, the Consortium) and shall be deemed as such as if Newco had been from the effective date of this Appointment. Thereafter, any reference to "you" in this Appointment shall also include Newco. If Newco is added to this Appointment, Newco shall be jointly and severally liable for your obligations hereunder.

20. Notwithstanding the above, in the event that:

a) another entity or entities joins the Consortium and/or Newco is established or incorporated (as the case may be); and

b) you do not amend this Appointment to reflect that the other entity or entities of the Consortium and/or Newco (as the case may be) is party to this Appointment and is our joint client along with you,

the other entity or entities of the Consortium and/or Newco (as the case may be) shall be deemed to be party to this Appointment and our joint client. In such circumstances you shall and shall procure that the other entity or entities of the Consortium and/or Newco shall enter into such instruments and/or documents as we shall deem necessary in order for the other entity or entities of the Consortium and/or Newco (as the case may be) to be party to this Appointment and our joint client.

21. To the extent that the other entity or entities of the Consortium or Newco become parties to this Appointment:

a) the other entity or entities of the Consortium or Newco (as the case may be) will be entitled to rely on our Services subject always to the provisions included in this Appointment; and

b) the reliance letter entered into by such other consortium member and/or Newco (as the case may be) shall be null and void.

General Terms of Business

22. Our Standard Terms and Conditions, as set out in Appendix 2, will apply to this work and govern our relationship with you and the terms thereof are incorporated into the Engagement Letter by reference. The Fee Letter, the Engagement Letter and all its appendices shall together form the "Appointment".

23. Notwithstanding any other provision of this Appointment, and except in the case of gross negligence, wilful misconduct or fraud, our total liability to all parties under or in connection with this Appointment (including any reliance letters issued hereunder) whether in contract (including by way of an indemnity), tort (including negligence), breach of statutory duty or otherwise shall not exceed the figure stated in Article 5 of our Standard Terms and Conditions.

24. Client acknowledges that the limitation of liability set forth in Article 5 of our Standard Terms & Conditions will apply in the aggregate to any and all claims, and Client waive the right to any claims above the limitation of liability set forth in Article 5. In the event of a claim, all parties to this Agreement agree that such claim must be brought as a collective action. All parties to this Agreement waive any right to bring separate claims against Arup in connection with this Agreement and / or Arup's services.

25. **Travel Restrictions:** The parties agree that, notwithstanding requirements specified elsewhere in this Proposal, persons engaged in the performance of this contract shall not be required to travel contrary to travel advice or where it is reasonably deemed that to do so would prejudice their health, safety or wellbeing. Arup shall use reasonable endeavours to facilitate the diligent performance of its obligations. However, Arup shall not be liable for any delay or disruption to the performance of any services arising from the COVID-19 outbreak.

26. **Travel Restrictions due to COVID-19:** In light of the recent declaration by the World Health Organization designating the outbreak of COVID-19 as a pandemic and in line with Arup's commitment to the health, safety and welfare of its staff, Arup reserves the right to cancel, postpone and/or restrict any domestic or international travel or visits to site in respect of the Project.

On completion of the Services, as part of our commitment to the quality of our service, we would welcome the opportunity to receive your views on the services performed by us. We will contact you in due course in order to make specific arrangements.

Please confirm your agreement with the terms of this Appointment by signing and dating a copy of this Appointment and returning it to us. Alternatively, you may instruct us to commence the Services by confirming in writing that the terms of this Appointment are acceptable.

We look forward to receiving your further instructions.

Yours sincerely

Jonathan Yates
Project Director | Associate Principal

Signature Page to Follow:

I have read and understood the terms and conditions of this letter and I confirm acceptance of them for and on behalf of **Inversiones Latin American Power Limitada** by whom I am duly authorized:

Signed…………………………

Name Esteban Moraga…………

Position CFO……………………………………………..

Date May 14, 2021…………………………………

Appendix 1: Scope of Work

In order to support our Client's needs, Arup proposes to undertake a desktop due diligence review of the assets during the binding offer stage, as follows. Our review will be based on proprietary information provided by Management.

1. Phase 1

Approach

We propose a desktop-based, due diligence process, using information provided by Management through the Virtual Data Room and virtual meetings with the management and operations teams.

1.1 Asset Characteristics and Integrity

- Provide a general description of the assets, including a review of the location, technology, key design elements (i.e. foundations, interconnection).
- Specifically, comment on the equipment / turbines employed and assess the robustness of the technology.
- Comment on the remaining useful life of the assets, under the light of the current maintenance structure and, if applicable, any life extension provisions.
- Review and comment on the Company's' integrity management systems / plans.
- Review and comment on the current condition of the assets and, when available, review inspection and maintenance records to confirm the condition of the infrastructure.
- Comment on design basis for the assets; in relation to resilience to hazards such as earthquakes.

1.2 Operational Performance

- Review and comment on the operational performance of the assets (serviceability, reliability, availability, etc.). Highlight historical operational issues and actual or proposed resolutions.
- Review and assess the operational / technical risks, from a lenders' perspective, and comment on the Company's mitigation strategies and plans.
- Comment on actual performance of assets compared to targets across generation, availability and component performance
- Comment on major reported incidents / failures and historical response times / performance.

1.3 Energy Yield Assessment Review

Conduct an independent yield assessment (post-construction) for Totoral and San Juan based on full SCADA data (10-minute wind speed and production information). We will provide updated yield assessments based on actual operational performance of the assets (through February 2020) and long-term resource trends. To conduct this scope of work, we will work closely with EMD as an expert wind yield assessment. We have assumed that the Client will be able to provide historical SCADA data for both (from COD through February 2021) assets to complete this portion of the scope of work.

1.4 Organization and Operations

Review and comment on the Company's:

- Organizational structure, with a focus on the technical support and O&M departments.
- Third-party contract management for operational and maintenance activities

1.5 Operations & Maintenance Review

- Review and comment on the appropriateness of the operations and maintenance (O&M) strategy and budget.
- Comment on the proposed contingencies and allowances included in Management's O&M budget.
- Conduct a historical review of performance against budget for operating costs and capital expenditures
- Summarize management's opex and capex projections. Comment on management's assumptions for future expenditures (opex and capex), given the existing and future production.
- Review the main O&M providers and key service agreements. Comment on price and sufficiency of scope, maintenance strategy, performance guarantees, track record of the parties, sparing philosophy, allocation of performance risk and incentives to perform, and termination scenarios.
- Comment on the potential replacement scenarios for the O&M contractor(s) to the extent this were to become necessary.
- Comment on long-term outlook for O&M strategy related to life extension potential of the assets.

1.6 Material Project Contracts

- Review and comment on the technical provisions included in the main supply and/or off-take agreements.
- Review and comment on any technical issues across project contracts (O&M, PPA, grid-connection) and the adequacy of the project's technical design and historical performance to meet contractual performance / supply requirements.

1.7 Financial Model Review

- Conduct a high-level review of the technical assumptions included in the base case financial model, specifically the technical, operating, construction, and schedule, when applicable, inputs as well as the capex and opex projections included in the model.
- Based on the risks identified during the technical review, work with you and your advisors to recommend sensitivity or downside scenarios to be included in the base case financial model.

1.8 Environmental, Health and Safety

- Describe the broad operating framework in which the assets operate and provide a high-level review of the level of compliance of with environmental, social and H&S regulatory requirements.
- Based on information provided by management, review any major accidents or incidents on site in the last five years, and comment on remediation actions taken to prevent future incidents.
- Review and comment on the company's health and safety performance to date.
- Review and comment on the Company's EHS management systems and governance structure.
- Review how the Company has managed during the current COVID-19 crisis and what lessons have been learned. Indicate if there is any ongoing exposure or risks related to potential future disruption of the business.

Optional EH&S Scope:

- If required by the lenders, Arup can provide a review of the Project's compliance with Equator Principles IV (EP-IV) and the IFC Standards.

1.9 Support to Financial Close

- Our scope of work includes 20 hours of support and review of the relevant portions of the financing documents, Q&A, videoconferencing, etc.

2. Phase 2 – Operations Monitoring (Optional)

If required by the financing parties, Arup can continue to monitor and report on the operational performance of the assets. Our operations monitoring scope includes, but is not limited to:

- Financial and operational performance against the base case projections
- Commercial monitoring (PPA and O&M agreements): claims, management of change, contractual performance, penalties, etc.
- Maintenance activities: planned and unplanned works; availability, ability to meet the business plan
- Staffing: technical capabilities to deliver the business plan.
- Environmental and EH&S compliance

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Appendix 2: Standard Terms and Conditions

For Technical Advisory Projects **(Version: AFL-01TA Rev)**

Date	***Client Entity (“Client”)***	***Arup Entity (“Arup”)***	***Owner Entity (“Owner”)***	***Project Title (“Project”)***	***Exhibits***
May 14, 2021	Inversiones Latin American Power Limitada	Arup Latin America S.A	*N/A*	**ILAP Onshore Wind Farms Refinancing Technical Due Diligence**	1. Engagement Letter 2. Scope of Work 3. Release Letter 4. Consent an Reliance Letter 5. Bring-Down Reliance Letter

1. EXTENT OF AGREEMENT: These terms and conditions are hereinafter referred to as the “Agreement” and supplement and govern all aspects of the obligations and liabilities between Arup and the Client relating to the Project. This Agreement and the Exhibits shall control and supersede all prior or simultaneous negotiations, representations and agreements, either written or oral including separate agreements between the Client and an Owner or other party if applicable. Should there be any conflict or discrepancy, this Agreement shall prevail. In the event that this Agreement is not fully executed, it shall nonetheless be effective and controlling to the parties so long as Arup has provided same to the Client and has begun work and not received written objections or modifications. Arup will not, and shall not be compelled to, commence work until a written notice to proceed is issued by the Client.

2. ARUP’S RESPONSIBILITIES: The Client appoints Arup and Arup agrees to perform the Professional Services identified in the Proposal pursuant to the terms and conditions set out in this Agreement. The term “Professional Services” and/or “Deliverable” shall mean the reports, opinions, letters and or the other deliverables prepared by Arup or its consultants in any medium, including graphic and pictorial representations, which relate to its professional services for the Project. Arup’s Professional Services shall be in accordance with current, accepted professional practice appropriate for the size, complexity, schedule, and other characteristics of the Project in the jurisdiction where the project is located. (“Standard of Care”). Arup shall comply with all reasonable instructions of the Client and shall keep the Client fully informed on the progress and status of the Professional Services. Arup shall carry out the Services regularly and diligently and shall liaise and co-operate with any other consultants appointed by the Client.

3. CLIENT’S RESPONSIBILITY: The Client shall provide the following: (1) Full information identifying its requirements for and limitations on the Project. (2) A representative authorized to act on the Client’s behalf with respect to the Project who shall render decisions in a timely manner pertaining to all requests and/or documents submitted by Arup. (3) All legal, insurance, and accounting services including auditing services that Client determines necessary to address its needs and interests relating to the Project. (4) Prompt written notice to Arup if the Client becomes aware of any Arup fault or defect in the Deliverable. (5) If applicable the Client shall review and approve submission for each phase of the work in a timely manner and shall authorize Arup in writing to proceed with each succeeding phase. (6) Access to information, records and project as required for Arup to perform the Professional Services. The Client shall fully cooperate with Arup and provide reasonable assistance as required by Arup in relation to the performance of the Services. Client warrants that the financing arrangements will not include investments from retail investors, whether bond holders or otherwise ("Retail Investors"). To the fullest extent permitted by law, Client agrees to release, defend, indemnify and hold Arup harmless from all claims, liabilities, costs, expenses, damages and losses (including but not limited to any direct, indirect or consequential losses, loss of profit, loss of reputation and all interest, penalties and legal costs and all other reasonable professional costs and expenses), legal actions, judgments, suffered or incurred by Arup in connection with investigating or defending against any claims or actions brought by any Retail Investors or by any other person pursuant to statute, at law, in equity or otherwise ("Claims") so far as Claims arise or are alleged to arise out of any alleged untrue statement contained in any report or other deliverable or information provided by Arup under or in connection with this agreement or, regardless of author, any statement derived therefrom The Client's financing arrangements will provide that notes (the "**Notes**") will be offered without being registered under the Securities Act of 1933, as amended (the "**Securities Act**"), (i) to qualified institutional buyers ("**QIBs**") in compliance with the exemption from registration provided by Rule 144A under the Securities Act ("**Rule 144A**") and (ii) in offshore transactions in reliance on Regulation S ("**Regulation S**") under the Securities Act to non-U.S. Persons (as such term is defined in Regulation S, each a "**Reg S Investor**"). The Client confirms that the Notes will be sold to institutional investors and not to retail investors.

4. ADDITIONAL SERVICES: Client requested services that are not expressly or implicitly identified in the Proposal as "Basic Services," shall be considered to be "Additional Services." Further, if Arup is delayed or disrupted in performing its services or its ability to meet any of its specific milestone dates is adversely affected in either case by the actions of the Client or others, or for reasons beyond Arup's reasonable control (including without limitation a Force Majeure Event), then: (1) Arup's liability for missing any milestone dates shall be reduced to the extent the delay is caused by the actions or failure to act of others or for reasons beyond Arup's control, (2) the time for performance of Arup's services shall be equitably adjusted, and (3) Arup shall be compensated for any additional resources employed as an Additional Service. If the Client requests that Arup perform Additional Services, both parties shall agree scope and fee for Additional Services. In the alternative, the Client shall provide Arup with additional compensation equal to Arup's hours expended at Arup's standard hourly rates, which is either attached to this agreement, part of the proposal or separately determined. Arup's hourly rates may be adjusted annually in accordance with Arup's standard practice. However, in no event shall Arup be compelled or required to perform what it deems to be an Additional Service unless the Client provides the appropriate written authorization.

5. LIMITATIONS OF LIABILITY: TO THE FULLEST EXTENT PERMITTED BY LAW AND EXCEPT IN THE CASE OF GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR FRAUD, CLIENT, RECIPIENTS AND ARUP EACH WAIVE ANY RIGHT TO CONSEQUENTIAL, LIQUIDATED OR INCIDENTAL DAMAGES AND AGREE THAT THE TOTAL LIABILITY, IN THE AGGREGATE, OF ARUP AND ARUP'S OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, AND INDEPENDENT PROFESSIONAL ASSOCIATES OR ENGINEERS, AND ANY OF THEM, TO THE CLIENT, AND ANY ONE CLAIMING BY, THROUGH OR UNDER THE CLIENT, FOR ANY AND ALL INJURIES, CLAIMS LOSSES, EXPENSES, OR DAMAGES WHATSOEVER ARISING OUT OF OR IN ANY WAY RELATED TO ARUP'S SERVICES, THE PROJECT INCLUDING INVESTMENT IN THE PROJECT OR THIS AGREEMENT, FROM ANY CAUSE OR CAUSES WHATSOEVER, INCLUDING BUT NOT LIMITED TO, THE NEGLIGENCE, ERRORS, OMISSIONS, STRICT LIABILITY, BREACH OF CONTRACT, MISREPRESENTATION, OR BREACH OF WARRANTY OF ARUP OR ARUP'S OFFICERS, DIRECTOR, EMPLOYEES, AGENTS OR INDEPENDENT PROFESSIONAL ASSOCIATES OR ENGINEERS, OR ANY OF THEM, SHALL NOT EXCEED THE GREATER OF THE TOTAL COMPENSATION RECEIVED BY ARUP FOR THE SPECIFIC WORK PERFORMED RESULTING IN CLIENT'S DAMAGES OR ONE MILLION DOLLARS. ARUP MAKES NO EXPRESS OR IMPLIED WARRANTY OR GUARANTY OF ANY SORT. SERVICES PROVIDED BY ARUP HEREIN ARE SOLELY FOR THE BENEFIT OF THE CLIENT AND ANY RECIPIENTS, INCLUDING INVESTORS OF THE TRANSACTION. NOTHING CONTAINED IN THIS AGREEMENT SHALL CREATE A CONTRACTUAL RELATIONSHIP WITH OR A CAUSE OF ACTION IN FAVOR OF ANY OTHER THIRD PARTY, EXCEPT FOR GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR FRAUD. ARUP SHALL NOT IN ANY CIRCUMSTANCES BE LIABLE IN CONTRACT, IN TORT (INCLUDING NEGLIGENCE), FOR BREACH OF STATUTORY DUTY OR OTHERWISE FOR (A) ANY LOSS OF INVESTMENT, LOSS OF CONTRACT, LOSS OF PRODUCTION, LOSS OF PROFITS, LOSS OF TIME OR LOSS OF USE; AND/OR (B) ANY CONSEQUENTIAL OR INDIRECT LOSS.

ARUP'S LIABILITY UNDER OF IN CONNECTION WITH THIS AGREEMENT OR ANY RELIANCE SHALL EXPIRE TWO (2) YEARS FROM THE MOMENT OF COMPLETION OF THE SERVICES.

IT IS UNDERSTOOD THAT CLIENT HAS NO PRIVITY OF CONTRACT WITH ANY ENTITIES AFFILIATED WITH ARUP ADVISORY INC. AND SHALL HAVE NO RIGHT OF ACTION AGAINST ANY AFFILIATE.

6. INDEMNIFICATION:

6.1. ARUP INDEMNIFICATION OF CLIENT: Arup shall indemnify the Client and its officers, employees and successors from and against all, damages, losses, and judgments, including reasonable attorney's fees and expenses to the extent they result from Arup's negligent acts or negligent omissions in the preparation of the Deliverables and for patent, copyright or trademark infringement attributable to Arup's services. Arup's liability arising from this indemnification and its liability for damages generally in connection with the Agreement shall be subject to the limitation of liability stated above. The Client acknowledges and agrees that Arup shall have no affirmative duty to provide a defense for the Client or any other party in connection with indemnified claims and that Arup's responsibility for reasonable legal fees of the indemnified parties shall be conditioned upon a finding against Arup of negligence by a court of competent jurisdiction and then only to the extent there is a clear nexus between the costs and the negligent act. The Client further agrees that, to the fullest extent permitted by law, no shareholder, officer, director, partner, principal, or employee of Arup shall have personal liability under this Indemnification provision, under any provision of the Agreement or for any matter in connection with the professional services provided in connection with the Project.

6.2. CLIENT INDEMNIFICATION OF ARUP: The Client assumes liability for and agrees to defend, indemnify and hold harmless Arup, its consultants, and their respective officers, directors, shareholders, partners, principals, employees, and successors from and against all damages, losses and judgments, including reasonable attorney's fees and expenses, to the extent they arise from or are alleged to arise from an act or omission of the Client, its agents, employees, consultants, contractors or construction manager (collectively for this indemnity "Client Entity"). Arup further agrees that, to the fullest extent permitted by law, no shareholder, officer, director, partner, principal, or employee of the Client shall have personal liability under this Indemnification provision, under any provision of the Agreement or for any matter in connection with the professional services provided in connection with the Project. It is understood that the limitation of liability stated in Article 5 shall be apportioned amongst all recipients of Arup's report to whom Arup has accepted responsibility. To the fullest extent permitted by law, Client agrees to indemnify, defend and hold harmless Arup from any liability it incurs in excess of the agreed limitation of liability stated at Article 5.

6.3. INSURANCE COVERAGES: Arup shall maintain professional indemnity insurance and other insurance policies as described below. As and when they are reasonably required to do so by the Client, Arup shall produce for inspection documentary evidence that such insurance is being maintained. All deductibles and premiums associated with the coverages stated below shall be the responsibility of Arup. Arup shall upon request provide to the Client certificates of insurance evidencing compliance with the insurance requirements. Arup shall maintain the following minimum amounts of insurance during the term of this Agreement including the following: (1) Workmen's Compensation, **Statutory**; (2) Employer's Liability, **$100,000**, General Liability, **$500,000**, Automobile Liability, **$500,000,** Professional Liability, **$1,000,000,** Umbrella Liability, **$2,000,000.**

7. COPYRIGHT AND INTELLECTUAL PROPERTY: Copyright and other intellectual property rights in all Deliverables, including but not limited to drawings, reports, calculations, specifications, software models and other documents prepared solely by Arup in connection with the Project remains vested in Arup. Any copyright and intellectual property rights created jointly for the purposes of the Project shall be owned jointly by the parties and may be used freely by each party for the purposes of the Project. Copyright and other intellectual property rights owned prior to this Agreement shall remain vested in the owner and shall not transfer to the other party. Client shall have a royalty free license to use the Deliverables for any purpose connected with or intended by the scope of the Project. Arup shall have a non-exclusive, irrevocable, royalty-free license to use any data or information supplied to it in connection with the Project (excluding personal data as defined under applicable data privacy legislation) for the purpose of improving its internal processes and project delivery. Where any data or information generated during the course of Arup's services is held within an externally-hosted data storage system, project extranet or similar hosted or controlled by the Client, the Client shall at any time up to 12 months from practical completion of the Project provide to Arup (or procure from a third party) access to all such data and information. The Client agrees to release, indemnify, defend, and hold Arup harmless from any and all liability resulting from unauthorized reuse of the Deliverables not in connection with the current subject matter of the Project.

8. TERMINATION AND SUSPENSION: Except as otherwise provided in this section, this Agreement may be terminated by either party upon not less than thirty (30) calendar days' written notice should the other party fail substantially to perform in accordance with the terms of this Agreement through no fault of the party initiating the termination. If the defaulting party fails to cure its default within the thirty (30) calendar day notice period or fails to commence action to cure its default when the cure cannot reasonably be completed within thirty (30) days, the termination shall take effect without further notice. If Client terminates their involvement in the Project prior to Preferred Bidder selection by the Owner, Arup shall be paid the Success Fee Lump Sum Bonus by the Client plus all fees and expenses for services performed through the date of the suspension. For any other suspension of services by the Client, Arup shall be paid for all fees and expenses for services performed through the date of the suspension plus reasonable valid demobilization expenses. In the event of a suspension of services, Arup shall have no liability for any delay or damage caused because of such suspension of services. Upon the resumption of Arup's services, Arup's fee shall be equitably adjusted and Arup shall be reimbursed for all expenses incurred as a result of the suspension. If the Client's suspension of Arup's services continues for more than ninety (90) calendar days, Arup may terminate this Agreement upon fourteen (14) calendar days' written notice to the Client.

9. PAYMENT PROVISION: Payments are due and payable no later than thirty (30) days from the date of Arup's invoices. Invoices will be submitted monthly, and will be based on actual labor hours worked and reimbursable expenses incurred, based on the fee schedule presented in the Proposal All monies secured by the Client by its client to pay for the Arup's services identified herein shall be deemed to be held in trust for Arup. In the event of a dispute pursuant to the services rendered hereunder, the Client shall not have the right to set off any payments due or owing to Arup. Payments due Arup and which remain unpaid shall bear interest 30 days from the date of the invoice at the rate of one and a half percent (1.5%) per month or the maximum amount permitted by law. Arup is entitled to recover any and all legal fees and any other costs expended if it becomes necessary to pursue legal actions to collect fees due hereunder. Client expressly acknowledges that Arup shall be entitled to a judgment for its attorney fees and court costs attributable to the collection of its fees which are ultimately adjudicated/arbitrated to be rightfully due and owing. Failure of the Client to make payments to Arup in accordance with this Agreement shall be considered substantial non-performance and grounds for Arup to terminate the Agreement. Reimbursable Expenses will be billed at cost. Reimbursable Expenses include the actual expenses incurred directly or indirectly in connection with the Project such as those for travel (including transportation and associated expenses); toll telephone calls; reproduction of Project-related documents, reproduction of drawings; filing and permit fees; delivery, express and courier services; and film and processing. This fee is in addition to the budget. No back-up data for time or copies of bills or receipts for Reimbursable Expenses will be provided unless otherwise agreed. Should such back-up data be required, it can be provided for the necessary copying charges, plus an administrative fee of ten percent (10%) of the portion of the invoice requiring verification. This fee is in addition to the budget. The Client shall pay any goods or services tax in respect of the services and all invoices are stated exclusive of such taxes and net of any withholding tax. Client shall take special care to review the email and domain when it receives invoices to confirm that they are genuine and not a cyber attack, such as phishing, pharming, etc., failure of hardware, software, human error, etc. and Client assumes all risk with no right of set-off or credit for an incident not the fault of Arup. To assist Client in fraud prevention, we have initiated a Digital Signature /Certificate to allow Client to ensure the emails they receive from us originate within the Arup network.

10. NO SOLICITATION OF EMPLOYEES: The Client agrees and acknowledges that it will not, directly or indirectly, solicit or hire or induce any employee of Arup to terminate his or her employment with Arup without the express written consent of the Arup. Recognizing that Arup has expended a substantial investment in recruitment, advertisement, testing, and training of their personnel, the Client agree that if it violates this clause and hires an employee of Arup within one year of the completion of the Project, it shall pay Arup for each employee thus hired, the amount of one year's salary, at the last level of annual remuneration that employee received from Arup.

11. CONFIDENTIALITY / RELIANCE: Arup shall be entitled to rely on the completeness and accuracy of services, information and documents furnished by or on behalf of Client. Arup shall not, except in the proper course of carrying out its obligations under this Agreement, disclose to any person or otherwise make use of any confidential information obtained in the course of the Agreement relating to the Client. If the Deliverable is a report (the "**Report**"), it is understood by the Client that it is intended for and may be relied upon by the Client. Subject to the execution by a third party involved or prospectively involved in the financing of the Project (a "**Recipient**") of Arup's standard form reliance letter attached hereto (each, an "**Reliance Letter**") as of each of the dates specified therein, Arup consents pursuant to this Agreement and the terms of the Reliance Letter to the release of the Report to the Client and each Recipient and the Client's and such Recipient's reliance on the Report. Arup further authorizes and consents to (1) the inclusion of the Report in its entirety in any Disclosure Document, (2) the inclusion of one or more summaries and/or excerpts therefrom in such Disclosure Document**; provided** that Arup shall validate the fairness and accuracy of such summaries and/or excerpts, (3) being named in such Offering Document as the independent engineer consultant for the Project, and (4) the circulation of the Disclosure Documents to the Recipients (it being understood that any Recipient must execute a Reliance Letter to rely on the Report). Cost estimates generated or modified by Arup are to be an "Engineer's Estimate" and represent Arup's judgment as a design professional familiar with the construction industry. It is recognized, however, that Arup does not have control over the cost of labor, materials or equipment, over the Contractor's methods of determining bid prices, or over competitive bidding, market or negotiating conditions. Accordingly, Arup cannot and does not warrant or represent that bids or negotiated prices will not vary from any Arup cost estimate or evaluation prepared or agreed to by Arup. Arup will be relying on information provided by others and does not accept responsibility for the accuracy of such information. Arup emphasizes that the forward-looking projections, forecasts, or estimates are based upon interpretations or assessments of available information at the time of writing. The realization of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. Actual events frequently do not occur as expected, and the differences may be material. For this reason, Arup accepts no responsibility for the realization of any projection, forecast, opinion or estimate. Findings are time-sensitive and relevant only to current conditions at the time of writing. Arup will not be under any obligation to update the report to address changes in facts or circumstances that occur after the date of our report that might materially affect the contents of the report or any of the conclusions set forth therein. Arup may supply written advice or confirm oral advice in writing or deliver a final written report or make an oral presentation on completion of the Professional Services. Prior to completion of the Professional Services, Arup may supply oral, draft or interim advice or reports or presentations but in such circumstances Arup's written advice or Arup's final written report shall take precedence. No reliance shall be placed on any draft or interim advice or report or any draft or interim presentation. The following notice, or a notice in substantially form, may be affixed to any report or other document furnished by Arup: *"This report (or document) was prepared by Arup _____("Arup") for the benefit of _____ solely in its capacity as Technical Advisor pursuant to an Agreement dated ____. No third party is entitled to rely on this report unless and until they and Arup sign a reliance letter in the form attached to our appointment. Arup does not in any circumstances accept any responsibility or liability to Retail Investors whether via bond issue or otherwise and no such party is entitled to rely on this report (or document). In preparing this report (or document) Arup has relied on information provided by others and Arup does not accept responsibility for the accuracy of such information. Arup emphasizes that the forward-looking projections, forecasts, or estimates are based upon interpretations or assessments of available information at the time of writing. The realization of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. Actual events frequently do not occur as expected, and the differences may be material. For this reason, Arup accepts no responsibility for the realization of any projection, forecast, opinion or estimate. Findings are time-sensitive and relevant only to current conditions at the time of writing. Arup will not be under any obligation to update the report to address changes in facts or circumstances that occur after the date* *of our report that might materially affect the contents of the report or any of the conclusions set forth therein."*

Arup explicitly does not permit circulation of and/or reliance upon any of its deliverables to/by retail investors and Arup will not accept any extension of responsibility and/or liability to retail investors. Client agrees to expressly indemnify, defend, release and hold Arup harmless against any liability arising from such unauthorized disclosure to such investors.

12. DISPUTE RESOLUTION: In recognition of the negative consequences associated with disputes both in terms of lost time and expense to all parties, the Client and Arup agree to settle their disputes by good-faith mediation as a condition precedent to the institution of legal proceedings by either party. If mediation would jeopardize the substantive rights of either party due to the application of any applicable statute of limitations, then mediation will be required during the dispute resolution process to the extent it may be used without jeopardizing the substantive rights of either party. The parties shall share the mediator's fee and any filing fees equally. The mediation shall be held in the United States of America, in the state of New York, unless another location is mutually agreed upon. In the event that the matter cannot be resolved through (or is not appropriate for) negotiation or mediation, the dispute shall be submitted for determination in the applicable courts of the state of New York and this Agreement shall be subject to and construed in accordance with the laws of that state. The Client shall not assert any claim against Arup more than two (2) years after the date of Arup's final invoice.

13. NOTICES / MODIFICATION / NO WAIVER / FORCE MAJEURE: Any and all notices or other communications required by this Agreement or by law to be served on, given to, or delivered to either party, shall be in writing and shall be deemed received upon receipt of telegraphic, facsimile or electronic notice. The Agreement may be amended only by written modification executed by both parties and may not be assigned without the written permission of the non-assigning party. The failure to put into effect, exercise or enforce any term, condition or provision of this Agreement shall not be deemed a waiver of such term, condition or provision or the party's right to enforce it. Should any part of this Agreement be rendered or declared illegal, legally invalid or unenforceable the remaining parts of this Agreement shall remain in full force and effect. The language shall not be construed for or against either party, regardless of who drafted it. This Agreement may be executed in one or more counterparts, each of which will be deemed an original and all of which taken together shall constitute one and the same document and a signature by facsimile or electronic mail may be used by any party to this Agreement as if it were an original signature. Each party shall execute and deliver all such further documents and instruments and take all such further actions as may be reasonably required or appropriate to carry out the intent and purposes of this Agreement. Neither the Client nor Arup shall be held accountable or penalized under the terms of this Agreement for the failure to perform which is occasioned by a Force Majeure Event, which shall mean an event or circumstance which is (1) beyond a Party's reasonable control, (2) the affected Party could not have reasonably avoided or overcome, and (3) which is not substantially attributable to the other Party. Force Majeure Events may include, without limitation, war, invasion, act of terror, strike (but not strikes or disputes unique to a Party), riot or other public disorder, intervening Act of God, natural disaster, hurricane force winds, tornadoes, disease outbreak, epidemic or pandemic, or other declaration of public health emergency, quarantine restriction.

Appendix 3: Release Letter

Your ref
Our ref
File ref

ARUP

77 Water St.
New York, NY 10005
United States
t +1 212 320 3663
jonathan.yates@arup.com
www.arup.com

[●], 2019

Dear

Project Title – Release Letter

We refer to our report dated [   ] in connection with the Project ("Report"), which was prepared specifically for and under the instructions of [*Client*] (the "Client") in accordance with an agreement dated [*insert date*] (the "Agreement").

We understand that you have requested sight of our Report. The Client has authorised us to provide a copy of the Report to you. This letter sets out the terms upon which we will agree to release the Report to you. You acknowledge and agree that:

1. The Report is being provided to you for information purposes only so you are aware of its contents but not for the purposes of reliance. We are not making any representation or warranty to you as to the accuracy, correctness or completeness of the information or of any analysis thereof contained in the Report. You should undertake your own due diligence with respect to the Project and matters covered by the Report and satisfy yourself as regards any requirements you may have.

2. The Report is prepared for use and reliance by our Client only and as otherwise agreed between the Client and us in the Appointment. You agree that, to the fullest extent permitted by law, we do not owe any duty or responsibility or liability to you, whether in contract, tort (including negligence) or otherwise in connection with the Report. You release and waive any and all claims or demands you might otherwise have against us, any of our subsidiaries or any officer, director or employee in connection with the Report.

3. The Report is strictly confidential and you shall not disclose all or any part of the Report to any other person, by any means, except:

(i) to your professional advisors; or

(ii) to the extent that disclosure is required by law or regulation, required or requested by any competent judicial, governmental, supervisory or regulatory body.

You will be liable for any and all damages, losses, liabilities, claims or expenses arising in connection with any breach of the terms of this letter by you or your representatives.

4. This letter shall not create or give rise to, nor shall it be intended to create or give rise to, any third-party rights under legislation or otherwise.

5. This letter shall be subject to and governed by New York Law and all disputes arising from or under the letter shall be subject to the exclusive jurisdiction of New York courts.

Please confirm your agreement to the terms of this letter by signing the enclosed copy of this letter and returning it to us, following which you will be entitled to receive a copy of our Report.

Yours sincerely

Jonathan Yates
Project Director | Associate Principal

Acknowledged and Agreed for and on behalf of _________________:

By: **Name:** **Date:**

Title (authorized representative):

Appendix 4: Consent and Reliance Letter Template

Your ref
Our ref
File ref

77 Water St.
New York, NY 10005
United States
t +1 212 320 3663
jonathan.yates@arup.com
www.arup.com

[●], 2021

Dear

Project Title – Consent and Reliance Letter

Arup ______. ("Arup") consents to the release of its ___________ Report (the Report) prepared specifically for the use of, and under the instructions provided by _________ (the "Client"), to ___________ *[recipient's name]* ____(the Recipient). Arup's Report was prepared pursuant to an agreement between Arup and Client, dated _____________(the "Agreement") and attached hereto.

In consideration of the Report being made available to Recipient and of Arup's consent thereto, the Recipients are deemed to acknowledge and agree to the following:

(a) Arup has used reasonable skill and care as described in the Agreement in the preparation of the Report and shall not owe you, Recipient, a greater duty than it has to Client in respect of the Report. Recipient understands and agrees that any use and reliance on the Report is subject to the terms and conditions of the Agreement including the limitations of liability in Article ___________________ of the Agreement.

(b) In performing the services, Arup has received information from third parties and has relied upon the reasonable assurances of third parties but cannot guarantee the accuracy of such information. It is understood and agreed by the Recipient that advisory services contain reasonable assumptions, estimates and projections which may not be indicative of actual or future values or events and are therefore subject to substantial uncertainty. Future developments or events cannot be predicted with certainty and may affect the estimates or projections provided, such that Arup does not specifically guarantee or warrant any estimate, opinion or projection. The Report will speak only as of its date, and Arup is under no obligation to update the Report to address changes in facts or circumstances that occur after such date that might materially impact the contents of the Report or any of the conclusions set forth therein. Arup confirms that it authorizes and consents to (1) the inclusion of the Report (or a draft of the Report) in its entirety in any Disclosure Document; (2) the inclusion of one or more summaries and/or excerpts therefrom to be inserted in any Disclosure Document, as approved by Arup; (3) being named in any Disclosure Document and/or indenture, purchase agreement or other financing document as the independent engineer consultant for the Project.

(c) Arup authorizes and consents (1) to the disclosure of the Report and each of its drafts to be made available to you for the purposes of evaluating the Project, and (2) your reliance on the Report subject to the restrictions and limitations in the Agreement.

(d) Except in the case of gross negligence, willful misconduct or fraud, Arup shall not in any circumstances be liable for (a) any loss of investment, loss of contract, loss of production, loss of profits, loss of time or loss of use; and/or (b) any consequential, incidental or indirect loss. Arup's total liability shall be limited pursuant to Article 5 of the Agreement. Arup's liability under or in connection with the Agreement shall expire two years from the date of the Report.

(e) The Report is confidential. Except for the inclusion of the Report and summaries in the Disclosure Documents and as otherwise required by law or regulation, as a result of its inclusion in any Disclosure Document, as required to establish a due diligence defense in connection with any claim or controversy arising out of the transactions set forth in the Agreement or with Arup's prior written consent, the Recipient will not disclose the Report or any part thereof to any other person or party at any time, other than to the Recipient's employees, officers, directors and professional advisors who need to know and are informed of the terms of this Reliance Letter ("Representatives"). The Recipient will be liable to Arup for any damages resulting from a breach of the terms of this Reliance Letter by the Representatives.

(f) It is expressly agreed that this Consent and Reliance Letter (this "Reliance Letter") sets out the entire agreement between us in relation to Arup's liabilities to Recipient in connection with the Report and that this Reliance Letter is personal to Recipient and shall not be assigned to any third party. To the extent of any inconsistency between the terms of this Reliance Letter and the terms of the Agreement, the terms of this Reliance Letter will prevail. In the event of a claim by Recipient, Arup shall be entitled to rely on the same rights and defenses against Recipient as Arup would have against Client under the Agreement.

(g) This Reliance Letter shall be governed by New York Law. This Reliance Letter may be executed in counterparts, each of which shall be deemed an original and all of which together shall constitute one and the same Reliance Letter, to the fullest extent permitted by 1aw. Delivery of an executed counterpart of this Reliance Letter by telecopier, email or facsimile shall be effective as delivery of a manually executed counterpart thereof. In the event that this Reliance Letter is not fully executed, it shall nonetheless be effective and controlling to any Recipient who received a copy of the Report.

Please countersign below to indicate your acceptance of the terms of this Reliance Letter and the Agreement. Upon return of a signed copy of this Reliance Letter, Arup shall provide to Recipient a copy of the Report.

Yours sincerely

Jonathan Yates
Project Director | Associate Principal

Acknowledged and Agreed for and on behalf of ___________________________:

By: **Name:** **Date:**

Title (authorized representative):

Appendix 5

BRING-DOWN RELIANCE LETTER

Arup Latin America, S.A.
[Address]

[__], 2021

Ladies and Gentlemen,

Re: Inversiones Latin America Limitada – Bring-Down Reliance Letter

Reference is made to the reliance letters dated _____, _____ and _____ (the "**Reliance Letters**") relating to the report by Arup Latin America, S.A. ("**we**" or "**us**"), entitled the "_____" dated _____, prepared for our client Inversiones Latin America Limitada (the "**Client**") in connection with the project consisting of the design, construction, rehabilitation, improvement, operation and maintenance works in respect of the concession granted to the Client thereunder. The report is referred to as the "Report", which was attached as Appendix _____ of the draft of the preliminary offering memorandum dated _____ (the "**Draft Preliminary Offering Memorandum**") and as Appendix _____ of the preliminary offering memorandum dated _____ (the "**Preliminary Offering Memorandum**"), which supersedes the Draft Preliminary Offering Memorandum, of [•], solely in its capacity as trustee, and not in its individual capacity, in connection with the issuance of senior secured notes as part of the financing of the Project.

Subject to the Reliance Letters and the terms of the Agreement by and between us and the Client dated [•], 2021, as amended and modified on _____, we have consented to the inclusion of the Report as Appendix _____ of the final offering memorandum dated _____ which supersedes the Preliminary Offering Memorandum.

We reaffirm as of the date hereof all statements made in the Reliance Letters.

[*Remainder of page left intentionally blank. Signature Page Follows*]

APPENDIX B INDEPENDENT MARKET CONSULTANT REPORT

VALGESTA
NUEVA ENERGÍA

ELECTRICITY MARKET REPORT

Prepared for

Latin American Power

May 2021

ELECTRICITY MARKET REPORT

Prepared for

Latin America Power

REV.	FECHA	PREPARED BY	REVISED BY	APPROVED BY	DESCRIPTION
0	May 17, 2021	J.B.A. J.I.R. T.C.S.	J.P.P.	J.P.P.	Market report.

THIS STUDY HAS BEEN PREPARED BY **VALGESTA** FOR **LATIN AMERICA POWER**.

PREPARED FOR:
LATIN AMERICA POWER

GLOSSARY OF TERMS

BESS: Battery Energy Storage System

CEN (“Coordinador Eléctrico Nacional”): Chilean Independent System Operator that oversees the operation of the Chilean Electrical System and the payment chain.

CNE (“Comisión Nacional de Energía”): Technical body in charge of analyzing prices, rates and technical standards to which energy production, generation, transport, and distribution companies must adhere, in order to have a sufficient, safe and quality service, compatible with the cheapest operation.

CPI: Consumer Price Index of the United States of America.

DGA (“Dirección General de Aguas”): General water directorate.

ERE (“Estado de Reserva Estratégica”): Strategic capacity reserve state defined by Supreme Decree Nº42/20.

LGSE (“Ley General de Servicios Eléctricos”): General Law of Electricity Services.

NCRE: Non-Conventional Renewable Energy.

PBP (“Precio Básico de Potencia”): Basic capacity price.

PEC (“Precios Estabilizados para Consumidores regulados”): Stabilized Price for regulated customers as enacted by law 21,185/19.

PELP (“Planificación Energética de Largo Plazo”): Long-term energetic planification developed by the Ministry of Energy.

PNP (“Precio Nudo Promedio”): Average nodal price.

PPA: Power Purchase Agreement.

SEC (“Superintendencia de Electricidad y Combustibles”): Superintendency of electricity and fuels.

SEN (“Sistema Eléctrico Nacional”): Chilean Electrical Interconnected System.

SIC (“Sistema Interconectado Central”): Central interconnected system. Was interconnected to the SING in late 2017 to create the SEN.

SING (“Sistema Interconectado del Norte Grande”): “Norte Grande” interconnected system. Was interconnected to the SIC in the 2017 to create the SEN.

SSMM (“Sistemas Medianos”): Medium systems.

VRE: Variable Renewable Energy.

TABLE OF CONTENTS

1 Introduction

The following report has been prepared by Valgesta, hereinafter the "Consultant", for Latin America Power (LAP), hereinafter the "Client", regarding the refinancing of ILAP.

ILAP, a limited purpose entity, is a wholly-owned subsidiary of Latin America Power S.A. and owner of San Juan and Totoral wind farms. Latin America Power (LAP) is wholly owned by Latin America Power Holdings B.V. (LAP), which is owned by BTG Pactual, Patria Investimentos, and GMR Energy.

- San Juan is a 193.2 MW facility located in Vallenar, consisting of 56 Vestas V117-3.45 MW wind turbines, which started operating in the first quarter of 2017.
- Totoral is a 46.0 MW facility located in Canela, consisting of 23 Vestas V90-2.0 MW wind turbines, and has been operating since 2010.

The contents of this report are as follows. Chapter 2 provides an overview of the Chilean electricity market, explaining the regulatory framework with the most important laws that govern the market. The main entities and segments in the Chilean electricity market are also described. Recent and ongoing regulatory modifications are also described.

Chapter 3 refers to market perspectives, methodological aspects for energy price projections and capacity credit estimation, and assumptions relevant for these projections.

Chapter 4 describes ILAP's portfolio characteristics, referring also to the performance of both wind farms.

Chapter 5 contains a PPA review describing the main terms of the most relevant PPAs of both wind farms.

Chapter 6 presents the results of marginal cost projections and capacity credit projections. A marginal cost projection is presented for several nodes in the system until the year 2040. Also, the capacity credit and revenues from the capacity market are also projected, also until 2040.

2 Market Background and Dynamics

2.1 Current regulatory framework

This section presents an overview of the regulatory framework of the Chilean electricity sector including the institutional framework, main laws and regulations, and recent regulatory changes.

2.1.1 Legal reform and vertical integration

The DFL N° 1 of 1982 established the General Law of Electricity Services (LGSE), introducing competition in the generation segment and dividing the functions of electricity generation, transmission, and distribution, that was pioneering at international level. All of this to promote a market structure which would lower the prices and improve the state of the segments overall.

Since then, the Chilean energy market has been running upon different market models. Several changes have been made in each of the different segments, although the main idea remains untouched, the energy must be provided to the user at minimum cost and the price paid for it must represent the real cost of producing it.

This is achieved by setting the price equal to the marginal cost of the energy. Thus, the price of the energy represents the cost of the system to supply one extra marginal unit to the users. This philosophy, added to the regulations made to solve market failures, form the basis of the Chilean energy market.

The main laws established from 1982 to date are as follows:

Table 1 Regulation timeline

1982 DFL N°1 - General Law of Electricity Services (LGSE)				
1990	1999	2000	2004	2005
Law 19,613	Law 19,613	Law 19,674	Law 19,940	Law 20,018
			"Short Law I"	"Short Law II"
2006	2008	2013	2015	2016
DFL N°4	Law 20,257	Law 20,698	Law 20,805	Law 20,936
"LGSE"	"NCRE Law"	"20/25 Law"	"Distribution Auction Reform"	"Transmission Law"

An overview of selected relevant Chilean electrical market laws is presented below.

2.1.1.1 Law 19,940, 2004 (Short Law I)

Short Law 1 was enacted by the Ministry of the Economy, Development and Reconstruction and published in March 2004. The key objectives of this initiative were to provide major consumers levels of security and supply quality at reasonable prices, providing the electricity sector with a modern and efficient regulatory framework that grants the necessary certainty and stability to the rules of the game in a strategic sector for Chile's development. Key aspects of Law 19,940 are the following:

- Reforms are introduced regarding the regulation of the operation and development of the transmission systems, improving the criteria used to allocate resources based on the use of the system by different agents. The procedure to establish transmission charges is specified. The objective was to enable the development and remuneration of 100% of the transmission system to the extent that it is an efficient expansion.
- Determination of nodal prices tends to stabilize values by diminishing the variation of the nodal price in relation to what is observed in the contract market with non-regulated customers. Previously, the nodal price could fluctuate within a band of 10% around the non-regulated price, but the band was modified by the new Law to 5%.
- Expansion of the non-regulated market, lowering the threshold for non-regulated customers from 2,000 kW to 500 kW.
- Specification of charge regulations, allowing suppliers, other than distributors, to supply non-regulated customers located in concession zones of distributors.

- Introduction of the ancillary services market, allowing the trade and valuation of technical resources that improve service quality and security.
- Reform of the tariff calculation mechanism in medium-sized systems (between 1,500 kW and 200 MW of installed capacity). This is especially applicable to the Medium Systems in the south of the country, Aysén and Magallanes.
- Improvement of conditions for the development of small non-conventional power plant projects, primarily renewable energy, by opening the electricity markets to this type of power plants, the establishment of the right to transfer their electricity through distribution systems and the possible exemption of charges for the use of the main transmission system (ex-Trunk System).
- Creation of a conflict resolution mechanism in the electricity sector, both between companies and the authority, and between companies, through the creation of the Panel of Experts.
- Through the price and transaction system, it is possible to identify sub-systems within an electricity system and independently identify new generation capacity requirements.

2.1.1.2 Law 20,108, 2005 (Short Law II)

The 1982 regulatory model established a process whereby the CNE calculated the electricity prices between regulated consumers and generators bi-annually. These prices reflected the expected marginal cost of supply on each of the main nodes of the system over the next few months. Additionally, the system operators calculated capacity payments to generators based on the generators' available capacity. Several supply adequacy problems in the 1990s and early 2000s uncovered the limitations of the Electricity Law in incentivizing the development of new generation and transmission capacity. The severe drought of 1998 and 1999 led to energy curtailments and price peaking across Chile mainly because the electricity industry lacked enough incentives for the development of a well-diversified generation mix. The spot market price signals were too volatile. Similarly, between 2005 and 2009, gas supply curtailment from Argentina led to a drastic drop in gas-fired generation.

The government addressed these risks to the nation's energy security through the implementation of a broad electricity sector reform with specific focus on making prices received by generators for their energy supply reflective of their market value. This reform was made through of the enactment of Law 20,018 (Short Law II) on May 19th of 2005, which requires distribution companies to procure their energy supply for regulated customers through auction processes. The auctions, which are open to existing and new participants, aim to reflect the cost expectations of generators and investors and mitigate spot market volatility risks. The main provisions of Law N° 20,018, some of which were later amended in a 2015 Law, include:

- Distribution companies must be 100% contracted all the time, for at least the next three years.
- Distribution companies must contract their energy supply through public, transparent, and non-discriminatory auctions.
- Distribution companies can either run their auctions individually or collectively with other distribution companies.
- Distribution companies can enter contracts for 15 years at fixed prices, indexed according to changes in certain variables.
- The authority sets the price cap and the capacity price, indexed according to the Consumer Price Index.
- Each generator offers a price and a volume of energy and the auction winners will be the generators which bid the lowest prices subject to demand coverage maximization.
- Contract prices are passed directly to consumers by means of a pass-through mechanism so that distributors have a constant yield for their assets, regardless of auction results.
- The lack of supply of Argentinean gas does not constitute majeure force.

2.1.1.3 Law Decree Nº4, 2006 (General Law of Electricity Services – LGSE)

The legal structure that regulates the activity of the electricity sector is DFL 4, enacted on May 12, 2006, by the Ministry of Economy, Development and Reconstruction that establishes the consolidated, coordinated, and systematized text of DFL N° 1, dated 1982, LGSE, on electricity matters. DFL 1 was modified in 2004 and subsequently in 2005 through the enactment of laws 19,940 and 20,028 called Short Law 1 and Short Law 2 respectively as mentioned before.

DFL 4 regulates the production, transport, distribution, concessions, and electricity tariffs. This legal structure includes the concessions regime, easements, prices, the conditions of quality and facilities security, machinery and instruments, and the relationship of companies with the State and individuals.

The General Law of Electricity Services and its supplementary regulations determine the technical and security standards to be used by any electrical facility in Chile.

2.1.1.4 Law 20,257, 2008 (NCRE Law)

On April 1, 2008, Law 20,257 came into force, establishing the obligation for generation companies that a percentage of their energy sold must be produced by NCRE sources. The list of NCRE technologies enlisted by this law are:

- Biomass
- Hydropower
- Geothermal
- Solar PV
- Wind
- Seawater energy
- Other technologies determined by the CNE

The main provisions of the law are:

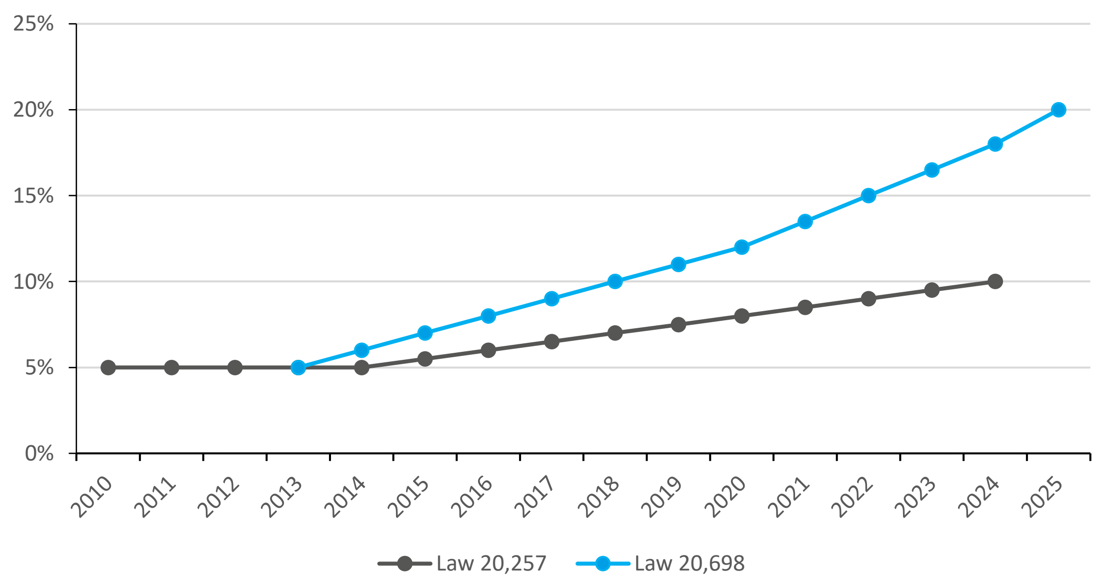
- Every generation company obtaining energy from electricity systems with installed capacity greater than 200 MW ("Norte Grande" Interconnected System and Central Interconnected System) to sell to distributors or final customers, shall guarantee that 10% of its purchases within each calendar year, has been injected into any of these power systems by non-conventional renewable generators, either their own or contracted.
- Between 2010 and 2014 the obligation to supply energy from non-conventional renewable generators will be 5%. As from 2015, this percentage will increase gradually by 0.5% annually, to reach 10% in 2024. This progressive increase will be applied in such a way that purchases affected by the obligation in 2015 must comply with 5.5%, in 2016 with 6% and so on, to reach 10% in 2024.
- An electricity company that does not comply with the obligation by the following March 1st of the respective calendar year, shall pay a charge of 0.4 UTM/MWh (approximately 30 USD/MWh) by which it falls short of its obligation. If within the following three years, the company again fails to comply with the obligation, the charge will be 0.6 UTM/MWh (approximately 45 USD/MWh) of deficit.
- This obligation shall be applicable as from January 1st, 2010, to all energy withdrawals for sale to distribution companies or final customers whose contracts were signed from August 31st, 2007 onwards, whether these are new, renewed, or extended contracts, or other agreements of a similar nature.
- Obligations may be accredited regardless of the interconnected system where injections are made (SING or SIC). The law establishes the necessary coordination of the CEN.
- Obligations may be accredited regardless of the interconnected system where injections are made (SING or SIC). The law establishes the necessary coordination of the CEN.

- Any electricity company that exceeds its obligation to inject renewable non-conventional energy may agree to transfer its surplus to another electricity company. These transfers may even be conducted between companies of different electricity systems.
- It is important to note that compliance with this Law is only valid for NCRE produced by facilities connected to the system from January 1st, 2007.
- For the exclusive purpose of accrediting the obligation established in the law, part of the injections from hydroelectric power plants whose maximum installed capacity is equal to or less than 40 MW is also recognized, even when hydroelectric projects greater than 20 MW are not defined as NCRE by the law. This recognition represents a proportional factor which falls to zero for installed capacity equal or greater than 40MW.

2.1.1.5 Law 20,698, 2013 (20/25 Law)

In October 2013, law 20,698 was approved. This law increases the quota established by law 20,257 (NCRE law) from 10% by 2024 to 20% by 2025, maintaining the penalties in case of not compliance. The following figure shows the non-conventional renewable energy obligations by law 20,257 and 20,698. It is worth saying that despite the obligation of 12% defined by Law 20,698, the NCRE injections over withdrawals subject to obligation as of December 2020 were of 35.6%.

Figure 1 NCRE obligation



Source: Own elaboration based on Law 20,257 and Law 20,698

2.1.1.6 Law 20,805, 2015 (Distribution Auction Reform)

In January 2015, the Congress approved a reform to the tender process for supply of regulated consumers of distribution companies, which aimed to make the tender process more competitive by giving more incentive to the generator's participation. As expected, this reform has increased transacted megawatt-hours and reduced the prices awarded through the auction process. The most relevant changes introduced by this law are the following:

- The CNE is now responsible for preparing the terms of the tender process while the distribution companies are only responsible for the administrative.
- The maximum contract duration increased from 15 years to 20 years.
- Supply contracts start five years after the corresponding bidding processes.
- New projects can postpone their entry or be canceled without penalties, provided that the delay or cancelation is attributable to a third party and beyond the control of the project.
- Provisions are applied in case part of the actual regulated demand is not covered by contracts. This is very unlikely but can occur if contracted generators become unable to fulfil their obligations. In this case, the uncontracted demand still needs to be supplied. This reform precludes the use of the spot market to supply the uncontracted demand and requires all available generators to contribute to meet this demand. The reform sets a limit of 5% above the regulated demand, up to which all generators in the system would have to provide the non-contracted supplies at a price equal to the maximum value between the short-term node price and the variable cost of each generator. For the supply of non-contracted demand beyond this 5% limit, generators must provide the required energy at the marginal price at the withdrawal node.
- The maximum connected capacity below which customers are classified as regulated customers increased from 2 MW to 5 MW from 2019.
- All bids are forced to be given in USD/MWh.
- Contracts remain private and bilateral between parties, which in this case correspond to distribution companies and generators. The state only takes part as a regulatory entity by approving the content of the contracts.

2.1.1.7 Law 20,936, 2016 (Transmission Law)

The new transmission law (Law 20,936) establishes new electrical transmission systems and creates an independent coordinator entity for the SEN that has been in effect since July 20, 2016. It introduced significant changes to the transmission payment scheme and to the transmission system expansion planning. It also introduced modifications regarding the entity that coordinates the operation, particularly taking into consideration the SIC and SING interconnection.

2.1.1.8 Law 21,185, 2019 (PEC Law)

Law 21,185, commonly known as "PEC Law" (Stabilized Price for Regulated Clients), referred to the stabilized prices for regulated consumers, was enacted on 2019 as a measure imposed with the goal of correcting and give a fast response to the problems occasioned by the social unrest of October 2019.

The PEC law creates a transitory mechanism of electricity price stabilization for clients subject to tariff regulation. Said tariffs are by these means stabilized, furthermore disposing that the maximum funds to be accumulated due to the application of the stabilization may not surpass 1,350 MM USD or be accumulated after June 2023.

Once any of the two milestones mentioned above occur (accumulation limit or accumulation end date), the payment of the debt will be realized through adjustments to the energy tariff, having the regulated customers to pay said debt until December 2027.

According to the Consultant's projections, the decrease in the electricity prices for regulated clients that can be perceived starting from January 2021 due to the entry of 2015/01 contracts will be captured by the PEC mechanism through a smaller accumulation of debt since that date on. This is related to the Average Nodal Price (PNP), as it will be lower and closer to the PEC price, hence the debt accumulation will be smaller. It is also forecasted that the payments that extinguish said debt accumulation will be paid from 2024 on, with the entry of the contracts of the 2017/01 tendering process. The effect of these contracts increases the difference between the PEC and PNP, which permits the distribution companies to increase their economical surpluses per energy sales, and hence, transfer that sum to the supply contracts that register debt due to the mechanism application.

On the other hand, and in contrast to the spirit of the implementation of this law, between 2022 and 2023 the Consultant foresees an increase on energy prices for regulated clients, of 2 CLP/kWh and 4 CLP/kWh, respectively. In this way, the scenario that can be observed between 2021 and 2033 for regulated clients implies:

- Higher prices compared to those of unregulated clients.
- Prices that do not decrease, in contrary, they increase between 2022 and 2033.
- Incapacity of capturing the positive effects of the entry of low-price contracts in 2024, given that these are absorbed by the credit payment that generators would perceive due to the application of Law 21,185.

2.1.1.9 Law 21,194, 2019 (Distribution Short Law)

In November 2019, the "Distribution Short Law" was enacted unanimously by the Energy and Mining Commission of the senate. This law modifies the distribution segment in terms of profitability for distribution companies, among other topics.

In first place, as it was mentioned above, the law modifies the profitability of the distribution companies from 10% before taxes to a band between 6% and 8% after taxes, which implies a reduction in tariffs for customers.

Furthermore, the law permits that the regulation and tariffication processes become more transparent, by eliminating and simplifying the cost-effective studies system used before the enaction of the law. Previously, two separate cost studies were developed; one by a consultant of the CNE and one by a consultant of the distribution companies, that would afterwards weigh 2/3 and 1/3 for the final calculation of distribution costs, respectively. This mechanism was eliminated by Distribution Short Law, keeping only one study for the definition of distribution costs, which will be audited by the Panel of Experts in case of discrepancies.

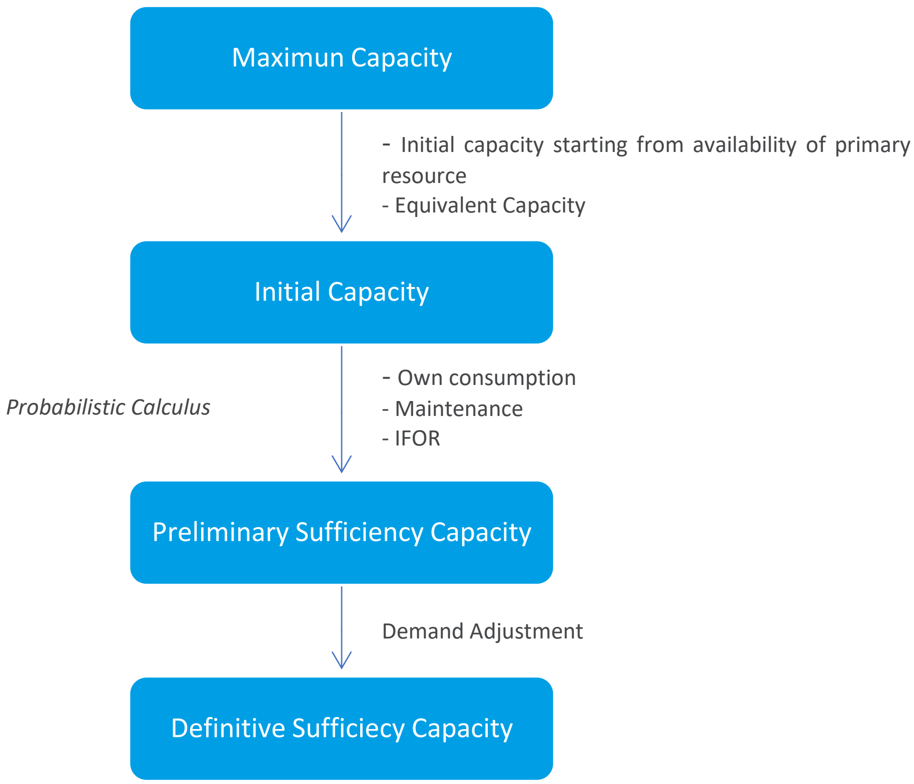
Finally, the distribution Short Law implies that all distribution companies must have a single business line, which implies that they will have to separately inform the authority about their distribution business related costs, and those coming from associated services, which are not directly related to distribution.

2.1.1.10 Supreme Decree Nº62, 2006 (Capacity Transfers)

In 2006 Supreme Decree Nº62 was enacted, which "approves the regulation of capacity transfers between generation companies established in the General Law of Electrical Services". Even though the document was modified afterwards by DS Nº44 of 2007, DS N°130 of 2011, and recently by DS Nº42 of 2020 (see section 2.1.1.11), the credit computation methodology has remained relatively stable, and it is in this decree where the conceptualization detail of the capacity transfers can be found, along with its calculation methodology.

In order to simplify the understanding of the mechanism of the sufficiency capacity recognition, the following explicative figure prepared by the Ministry of Energy is included below.

Figure 2 General scheme of the sufficiency capacity calculation methodology



Source: Ministry of Energy

In the previous figure, it is shown that the recognition of sufficiency capacity starts with the maximum capacity of every unit. In the case of old units, this maximum capacity is audited periodically, whereas for new projects the CEN uses the declared capacity by the owners.

Afterwards, the CEN takes into action an availability calculus of the primary resource of generation, considering the capacity factor of the units and the equivalent capacity, given by the operation states of the unit. With this an initial capacity is obtained, which, because of being based on concrete and past data, it is considered a deterministic calculation.

However, the calculation of the preliminary sufficiency capacity, which corresponds to the step prior to obtaining the definitive capacity, is a stochastic calculation that depends on the own consumption of the unit, maintenance factor, and forced unavailability.

Once the preliminary capacity of the system is obtained, the 52 hours of maximum demand are used to obtain the capacity repartition for all the units and calculate an adjustment factor, corresponding to the average of the 52 hours of maximum demand divided by the preliminary sufficiency capacity of the system. Applying said factor to every unit the definitive sufficiency capacity can be obtained.

2.1.1.11 Supreme Decree Nº42, 2020 (Sufficiency Capacity Modifications)

Supreme Decree Nº42 (DS 42) modifies Supreme Decree Nº62 of 2006 (DS 62). This last document approves the regulation for capacity transfers between generating companies stablished in the General Electrical Services Law. The main aspects of the new document are the definition of the Strategic Reserve State (ERE, for its Spanish translation), and the consideration of storage systems in capacity transfers.

Both aspects mentioned are aligned with the decarbonization plan and the implications of not counting with the capacity and sufficiency that this type of units undeniably support to the system. It is worth pointing out that the modifications to the regulation allow redirecting resources that today are received by coal-fired units, that because of the merit order practically never generated energy. However, according to the methodology of the DS 62 they are available, and thus they receive payments associated to this concept. On the other hand, part of the coal-fired units that operate in the SEN have an official decommissioning date, which allows to estimate the impacts that such modification would have in the sufficiency capacity market.

Since the announcement of the decarbonization plan framed in the 2019 Conference of the Parties (COP19), the best way of proceeding with the accelerated decommissioning of thermal coal-fired units without compromising the system’s security has been discussed, apart from searching incentives for an anticipated closure. DS 42 introduces a new operational state (ERE), which seeks to maintain units connected and available for an eventual operation whose decommissioning has already been approved. The main objective of this measure is to grant security guarantees and delivering the decarbonization process in the correct manner.

The sufficiency capacity of a unit under the ERE will be, in the best-case scenario, 60% of the previously recognized capacity prior to the state change. With this payment, the authority intends to give an economic signal for units that would be maintained as a reserve for the system, paying an insurance in case of an unfavorable hydrology or postponement of the construction of critical infrastructure.

Modifications raised by the authority in DS 42 have provoked controversies between different agents of the electrical market. In first place, there are those who affirm that the ERE represents a subsidy for coal-fired units, including those that have more than 40 years of operation based on obsolete technologies. There are also agents that accuse an eventual distortion of the electrical market due to the modifications, as it will be remunerating units for a non-existing service, arguing that the 60-day term to recover operations is too much and should not be considered as real backup units when facing system failures.

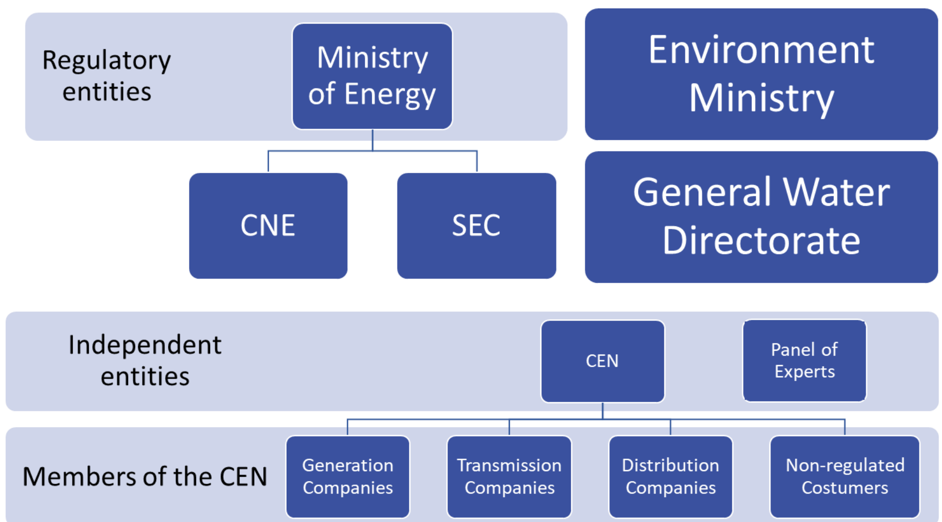
Two new definitions are incorporated in DS 42, for units that have storage capacity or regulating the primary variable resource. In first place, renewable units with storage capacity is referred to those units capable of generating and storing energy in the same interconnection node to the system. The storage component is understood as permitting the transformation of electrical energy into other type of energy, for its storage and posterior injection. In second place, renewable units with regulation capacity is referred to those units with the ability of managing the resource before injecting to the system. Every generation unit with a primary resource different to hydropower and that qualifies in any of the two definitions mentioned, will have its sufficiency support adequately recognized.

With this new definition, the recognition of the sufficiency delivered by the storage and regulation of the primary resource is no longer an exclusive faculty of hydric-based units. However, DS 42 is not clear about the criteria and the methodology of the recognition of said sufficiency, which should be stablished in the respective technical normative.

2.1.2 Institutional framework

The Chilean electricity sector is intricately linked to different public and private sector institutions. These institutions and market agents may interact through coordination, direct dependency, contractual, property and binding relationships. Main institutions participating in the Chilean electricity sector are as follows:

Table 2 Regulatory entities



2.1.2.1 Ministry of Energy

The Ministry of Energy is an autonomous institution created by law 20,402 in 2010. This Ministry is the entity in charge of producing and coordinating the plans, policies and standards for the correct operation and development of the energy sector and advises the Government on all energy related matters.

The Ministry grants final approval of tariffs and node prices set by the CNE, and it grants concessions for hydroelectric power plants, transmission lines, substations, and power distribution areas.

The energy sector comprises all activities of study, exploration, exploitation, generation, transmission, storage, distribution, consumption, efficient use, import and export, and any other related matter with electricity, coal, gas, oil and derivatives, nuclear energy, geothermal and solar, and other energy sources.

2.1.2.2 National Energy Commission (CNE)

The CNE is a technical agency, created by Decree Law 2,224 of 1978, and modified by law 20,402.

This agency oversees analyzing and setting prices, tariffs, and to prepare technical standards for generation, transmission, and distribution segments. Its main functions are the following:

- Analyze at a technical level prices and tariffs of energy services.
- Establish technical standards about the operation of energy facilities.
- Advisor to the government through the Ministry of Energy, overall related matters to energy sector.
- Monitor and project the current and expected operation of the energy sector and propose to the Ministry of Energy legal and regulatory rules.
- Calculates regulated customers tariffs and nodal prices.
- Manages the transmission expansion process every year, including setting the Regulated Return on Rate Base (AVI) and operation, maintenance, and administration cost (COMA).

2.1.2.3 National Electrical Coordinator (CEN)

In the beginning of the Chilean electric system, the system operator started as a group of electrical companies that needed to coordinate the energy supply and demand. Then in 1985 it was created by law an economic dispatch center. There were two entities, according to the interconnected system that they coordinated, north and central-south, which were the SING and SIC. The system operator of each system was called CDEC-SING and CDEC-SIC. CDEC stands for “Centro de Despacho Económico de Carga”.

With the latest changes of the New Transmission Law and the interconnection between SING and SIC systems in November 2017, the CDEC-SIC and CDEC-SING were merged into one single National Coordinator, the CEN.

The main task of this organism is to economically dispatch the generation units ensuring system security at minimal cost, as well as computing many of the payments related to the electricity market between the different segments.

2.1.2.4 Superintendence of Electricity and Fuels (SEC)

The Superintendence of Electricity and Fuels was created in 1984 and its functions have evolved ever since. According to Laws 18,410 of 1985 and 19,613 of 1999, it has the mission of supervising the correct operation of electricity, gas, and fuel services in terms of their safety, quality, and price.

Responsibilities of the SEC involve supervising compliance with legal and regulatory provisions, signing temporary concessions for gas production plants, power plants, electrical substations, transmission and distribution system power lines, conflict resolution, authorizing rights of use, and imposing fines, among others.

2.1.2.5 Panel of Experts

The Panel of Experts of the General Law of Electricity Services is an entity created by Law 19,940 exclusively for the electricity sector, with limited powers, involving professional experts whose function is to resolve, through binding rulings, any disagreement or conflict arising from the application of the electricity legislation, and any other disputes that two or more companies of the electricity sector may agree to submit to the Panel's decision.

The institution is comprised of professionals with a long and wide-ranging professional or academic experience. Five of them must be engineers or possess a degree in economic sciences and two must be lawyers. Panel members and a Lawyer Secretary are appointed for six-year periods. The Panel's composition is partially renewed every three years.

2.1.2.6 General Water Directorate

The General Water Directorate (DGA) is the entity in charge of overseeing the hydric resources of the country, encouraging the management and administration in a framework of sustainability, public interest, and efficient allocation.

Its functions are indicated in the D.F.L N°850 from 1997 from the ministry of Public Works (MOP) and referred to what is contained in the Water Code, D.F.L N° 1,122 from 1981 and the D.F.L MOP N° 1,115 from 1969.

2.2 Chilean market segments overview

The following section realizes an overview of main characteristics and role in the electricity markets of the main segments of the system. These are: Generation, Transmission, and Distribution. The tendering process is also described, in which the segments to be mentioned participate.

2.2.1 Generation segment overview

To understand the generation segment, it is important to bear in mind the parties that are involved in the electricity market. The customers of this market can either be regulated or non-regulated, the difference is that for regulated customers the tariff is set by the authority (CNE), while for non-regulated costumers it is mandatory to negotiate a tariff structure with the suppliers through a bilateral contract.

It is important to note that the concept of physical bilateral contracts[1] does not exist in the Chilean electricity market. In the case of Chile, supply contracts (Power Purchase Agreements (PPAs)) is only of a financial nature. In this context, the supplier agrees to sell electricity at a certain price to the customer at a specific node of the system.

The financial nature of these contracts means that the supplier agrees to hedge the difference between the marginal cost and the price set upon in the contract. Thus, the consumption made by the consumer (referred to as “withdrawal”) will mean a cost to the generator each time the marginal cost of the specific node is above the contract’s price and a revenue if the price of the contract is higher than the marginal cost.

Electricity supply contracts can be classified in three groups:

- Contracts with regulated distribution companies: these contracts are awarded through competitive auction processes.
- Contracts with non-regulated customers (also called free clients): these customers are entitled to sign contracts directly with generation companies and to freely negotiate prices.
- Contracts with other generation companies.

[1] Physical Contract: Supply contracts between private parties that are reported to the System Operator and then translated into a physical dispatch.

In the generation segment, four generation companies cover approximately 61% of the total installed capacity in the SEN. These companies are ENEL Generación, Colbún, AES Gener and ENGIE.

As mentioned previously, generators can either sell their energy in the spot market or through bilateral contracts agreed with customers. The Chilean spot electricity market is a mandatory pool type market coordinated by an independent system operator and with audited generation costs and an hourly nodal spot market restricted to generators[2]. This aspect distinguishes the Chilean market from those based on intra-day energy auctions with free sales and purchases.

The CEN is the entity that coordinates the operation of the SEN. The CEN oversees the physical dispatch hour by hour, which is based on the operational cost information provided by each generating company. Thus, the SEN's operation is the result of the centralized dispatch determined by the CEN.

In a pool type market, the hourly dispatch for the system essentially represents a merit order curve based on the variable operational cost of each unit. The spot price of electrical energy is obtained from the short-term marginal cost resulting from the instantaneous balance between supply and demand. This nodal spot price is used for commercial exchange of electricity in the system between generation companies.

It can be said that the spot market is comprised of generation companies that trade energy and capacity between them, considering the supply contracts they have agreed upon. Companies that generate in each time more than what they have committed in their PPAs (companies with surplus) sell the excess to those companies that have generated less than what they have contracted with their customers (companies with deficit). This trading activity helps keeping the balance between supply and demand at a systemic level. Physical and economic transfers (sales and purchases) are determined by the CEN. In the case of energy, the amounts traded are valued on an hourly basis at the marginal cost (spot price) resulting from the operation of the system during that hour. In the case of capacity, transfers between companies are valued at the nodal price of capacity, which is a regulated price. The nodal price of capacity is determined every six months by the CNE and represents the expansion investment cost for the most economical technology for supplying electric power during demand peak hours. Each generation unit has a capacity recognized, which is used to determine its capacity revenue (sales of capacity).

[2] Both regulated and non-regulated clients obtain their energy from bilateral contracts

2.2.2 Transmission segment overview

Prior to the Chilean power sector reform in the 1980s, the transmission sector was 100% owned and operated by Endesa (Empresa Nacional de Electricidad). Although the reform sought to encourage competition, Endesa continued to control 95% of the transmission sector in the 1990s. In 1993, Endesa created its subsidiary company Transelec to run the transmission business. Citing market power concerns with generation companies owning transmission assets, the Antimonopoly Commission ordered Endesa to sell its transmission business. Endesa sold Transelec to Hydro-Québec International (HQI) through an international bidding process in 2000. HQI, in turn, sold Transelec to a Canadian consortium (Brookfield Asset Management, Canadian Pension Plan Investment Board, British Columbia Investment Management Corp. and Public Sector Pension Investment Board) in 2006. In 2017, Brookfield reached an agreement with China Southern Power and sold its share.

In the 1990s, lack of investment and competition in the transmission sector were attributed to the tariff structure, which was considered to result in insufficient incentives for the construction of new transmission lines. To align investor incentives, the Chilean government introduced Short Law 1 (Law 19,940) in 2004. This law modified the methodology for calculating transmission tariffs with the goal of improving the incentives for developing the transmission system. It also amended the transmission system expansion procedures.

More recently, in 2016, law 20,936, called “New Transmission Law” came into force, establishing a new electric transmission system and creating an independent coordinator of the SEN. This law includes changes on aspects such as transmission segment definition, remuneration, tariff review, expansion planning methodology, and transmission access.

Currently, according to law 20,936, the segments of the transmission sector are the following.

National Transmission System

- The National Transmission System, called Trunk Transmission System prior to the law 20,936, is the system that allows the formation of a common electricity market, interconnecting the other transmission segments and making it possible to supply the total system demand, on different scenarios of generation facilities availability, including contingencies and outages, considering the service quality and security features established in law 20,936, regulations, and technical standards.

Zonal Transmission Systems

- The Zonal Transmission System, called Subtransmission System prior to the law 20,936, consists of electric lines and substations that are essentially arranged for the current or future supply of regulated, territorially identifiable customers, without prejudice to the use by free clientes or generation facilities connected directly or through transmission systems dedicated to said transmission systems.

Dedicated Transmission Systems

- The Dedicated Transmission Systems, called Additional Transmission Systems prior to law 20,936, are the systems essentially used to supply non-regulated customers or to inject energy to the electrical system by power plants. The use of dedicated lines is determined by bilateral transmission contracts between the users and the facility owners.

Transmission Systems for Development Poles (or Zones)

- The Transmission Systems for Development Poles are intended to facilitate the injection of electrical energy from power plants, located in a given development pole or zone, to the transmission system.
- Law 20,936 defines development poles as areas of the country where there are non-conventional renewable energy resources for the electricity generation, whose benefits are of public interest, having to comply with the environmental legislation and land use planning.
- The development poles are determined by the Ministry of Energy on the long-term energy planning report. The Ministry must prepare a technical report for each development pole, specifying one or more areas which meet the characteristics above mentioned, distinguishing each generation source type.

International Interconnection Systems

- The International Interconnection Systems are intended to enable the export or import of electrical energy, from and to the national electrical system.
- Within these systems it is possible to distinguish international interconnection facilities of public service and of private interest. The international interconnection facilities of public service will be subject to open access. On the other hand, the international interconnection facilities of private interest will be subject to their respective contracts and to the electrical regulatory framework.

2.2.3 Distribution segment overview

Distribution systems comprise lines, substations, and equipment that allow the delivery of electricity to end-users located in a certain limited geographical zone. The Chilean regulatory framework establishes two voltage ranges for the distribution sector:

Low Voltage Distribution

- This comprises electrical distribution equipment at voltage levels lower than 400 V. Chilean low voltage networks operate at 220/380 V.

High Voltage Distribution

- This includes systems from 400 V to 23,000 V. Chilean high voltage distribution networks (or feeders) most commonly operate at 12, 13.2 or 23 kV.

The distribution activity is considered as a natural monopoly due to economies of scale, as it is more efficient for a single company to supply the demand in each zone. Distribution companies in Chile operate as a concession system of public distribution services, implying a service obligation with clients inside their corresponding concession area.

Figure 3 Customer classification

Distribution companies can have two types of customer:

Regulated customers	Non-regulated customers
• Consumers with a connected capacity less than or equal to 5 MW, located within the concession area of a distribution company; consumers with a capacity between 0.5 MW and 5 MW can choose to become non-regulated customers. • This segment includes residential clients and small to medium-size commercial and industrial consumer.	• Consumers with a connected capacity over 5 MW, but smaller consumers can also enter into this category if their demand is higher than 0.5 MW. • These customers are not subject to price regulation, and they negotiate prices and supply terms with energy providers in the form of bilateral contracts. In Chile, there is no retail market operated by dedicated traders; therefore, energy and capacity supplied to non-regulated customers is contracted directly with generation or distribution companies through bilateral contracts. • The customers of this category are usually large industrial users or mining companies.

[3]

In the distribution segment four distribution companies supply approximately 97% of the total regulated clients of the SEN. These companies are CGE, ENEL, SAESA, and Chilquinta, where the first two companies mentioned have 72% of the total clients of the SEN.

2.2.4 Tender process 2021/01

This section encompasses technical elements of the tendering process 2021/01, such as energy blocks and sub-blocks, distribution companies, purchase nodes, bidding nodes, and remuneration regime.

The supply blocks correspond to the maximum energy compromise contracted that the bidder could assume, which is divided into sub-blocks composed by a base component and a variable component. The variable component is equal to 5% of the base component, and it seeks to absorb unwanted energy demand increases.

[3] Connected Capacity: Maximum consumption capacity from the electricity grid.

For the tendering process 2021/01, only one block will be tendered, denominated Supply Block Nº1, which has January 1st, 2026 as supply start date and December 31st, 2040 as supply end date. It is composed of three hourly supply blocks. These last blocks are divided into 110 sub-blocks, each of them with the same amount of annual energy and same supply start and end dates.

Table 3 Hourly supply blocks for the Tendering Process 2021/01

Block	Hours	Base Component [GWh]	Variable Component [GWh]	Total [GWh]
BS N°1-A	00:00 – 07:59 23:00 – 23:59	698	35	733
BS N°1-B	08:00 – 17:59	989	49	1,038
BS N°1-C	18:00 – 22:59	513	26	539
Total		**2,200**	**110**	**2,310**

The supplier will be able to solicitate to the CNE the extension of the supply period making use of the complementary supply period, according to the same conditions stipulated in the contract and using the same amount of energy contracted corresponding to the last year of supply. The CNE will approve said solicitude in case that the total accumulated energy effectively invoiced by the supplier is less than the total compromised energy by the base component of the supply block.

The CNE will consult the supplier its will of making use of the extension mechanism, which goes from 2041 to 2043. The supplier can make the solicitude until the 31st of December of 2038. The complementary supply period will have the following validity, according to which option is accomplished first:

1. Until 31st December, 2043.
2. Until the invoicing of the remanent energy equivalent to the difference between the total effectively invoiced energy and the total compromised energy of the base component of the supply block.

Distribution companies will subscribe supply contracts in separate ways with the awarded suppliers. For representativity purposes, Enel Distribución is defined as the mandatary distribution company, which means that it can represent the remaining suppliers in the contract’s subscription. The distribution companies of the process are shown below.

Table 4 Distribution companies, Tendering Process 2021/01

Distribution Companies		
CEC	COPELEC	LITORAL
CGE	CRELL	LUZ OSORNO
CHILQUINTA	EDECSA	LUZLINARES
CODINER	EEPA	LUZPARRAL
COELCHA	EMELCA	MATAQUITO
COOPELAN	Enel Distribución	SAESA
COOPREL	FRONTEL	SOCOEPA

The only bidding node in which the proponents must deliver prices and energy offered is Polpaico 220 kV. On the other hand, the purchase nodes correspond to all the nodes in which the distribution companies get their electrical supply. Both the bidding node and the purchase nodes have associated factors that are defined in the short-term nodal price decree valid at the invoicing moment, which are used to reference the offered price in the bidding node to all the purchase nodes.

Appendix 19 of the tender terms and conditions contain the supply contract model, which contains the rights and obligations of the proponents and distribution companies.

The price in the bidding node corresponds to the offered price by the proponent in its economic offer, indexed biannually using the formula exposed in the Appendix 9 of the bases. In this way, the energy price will correspond to:

$$Price_{energy} = Price_{base} \cdot \left(a_1 \cdot \frac{Index_1}{Index1o} + a_2 \cdot \frac{Index_2}{Index_{2o}} + a_3 \cdot \frac{Index_3}{Index_{3o}} + a_4 \cdot \frac{Index_4}{Index_{4o}} \right)$$

Where:

- $Price_{base}$: Base Price of energy in the bidding node, corresponding to the energy Price of the economic offer, in USD/MWh.
- $Index_i$: Value of index "i" used in the indexation formula. The monthly average of the index will be used for 6 months counted from the third month prior to the evaluation of the indexation formula.
- $Index_{io}$: Base value of index "i". It considers the monthly average of the last six months starting from the third month prior to the offer presentation date.
- a_i: Weight associated to the index "I". All weights must be bigger than 0, and they must add up to 1. The sum of the weights associated to fuels (1 to 3) must not be more than 0.7.

Table 5 Indexes for energy price indexation

N°	Index
1	Diesel
2	Brent
3	Henry Hub
4	Consumer Price Index, EEUU (CPI)

Once the indexed Price is calculated, it is referenced to the purchase points multiplying by the quotient between the modulation factors of the purchase node and bidding node.

On the other hand, the capacity price during peak hours in the bidding node corresponds to the price fixed in Supreme Decree Nº12T/20, which is, 7.7767 USD/kW/month. This price is biannually indexed using CPI, in the following way:

$$Price_{capacity} = Price_{base\_capacity} \cdot \frac{CPI}{CPI_o}$$

As it happens with the energy price, the capacity price during peak hours in the purchase nodes corresponds to the indexed base price multiplied by the quotient between the modulation factors of the purchase node and the bidding node.

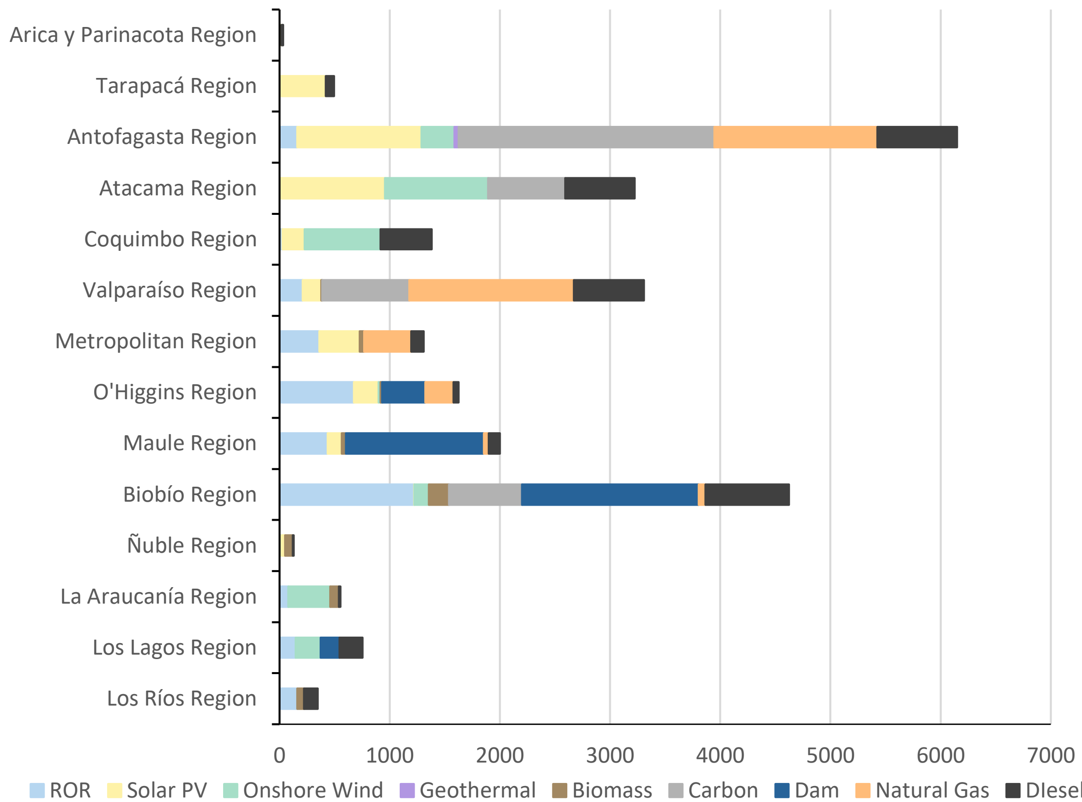
It is important to consider that the only suppliers that will be able to sell capacity during peak hours are those who contain the peak demand period defined for the system (18:00 – 22:00). In this case, the block corresponds to 1-C, and hence the contracts signed during the solar block will not be able to sell energy during peak hours.

2.3 General overview of the Chilean electricity market

2.3.1 Composition of supply and demand

This section focuses on delivering information on the composition of supply and demand of the Chilean electricity market. Topics revised in this section include installed generation per region and technology, historical generation of the SEN, installed capacity per generation company, market share and participants of the distribution and transmission segments, and composition of demand divided in regulated and unregulated clients. The following figure shows the installed capacity of the SEN per technology and region.

Figure 4 Installed capacity per region and technology.



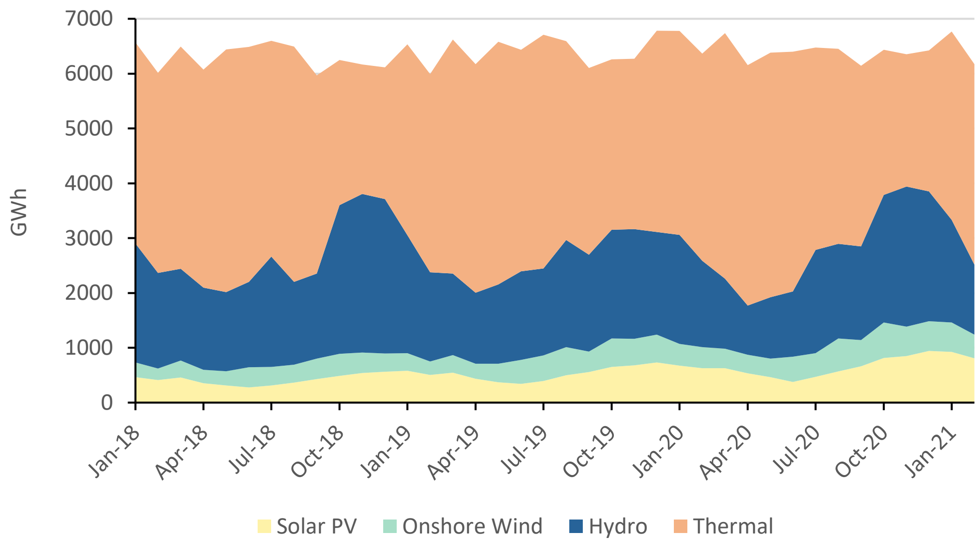
Source: Own elaboration based on CEN

As it can be seen, there is a wide variety of technologies operating in the SEN. Regions with the greater installed capacity are Antofagasta Region and Biobío Region. The first one has also the greater installed capacity of coal-fired units, but its solar deployment has increased during the last years and it is expected to grow even more, replacing the coal-fired units that will be decommissioned in the following years.

Regarding other renewable energies, Biobío Region shows a big amount of installed capacity in dam units, reaching a 34.7% of the total installed capacity of the region. A great amount of dam installed capacity can also be seen in the Maule Region, reaching 62.7% of its total installed capacity.

Onshore wind units are mostly seen in the Atacama and Coquimbo regions, adding up to 1,623 MW out of the 2,678 MW of installed onshore wind capacity throughout the SEN. The following figure shows the monthly generation of the SEN by technology, grouping all thermal technologies, and grouping dam and run-of-river units for a better visualization.

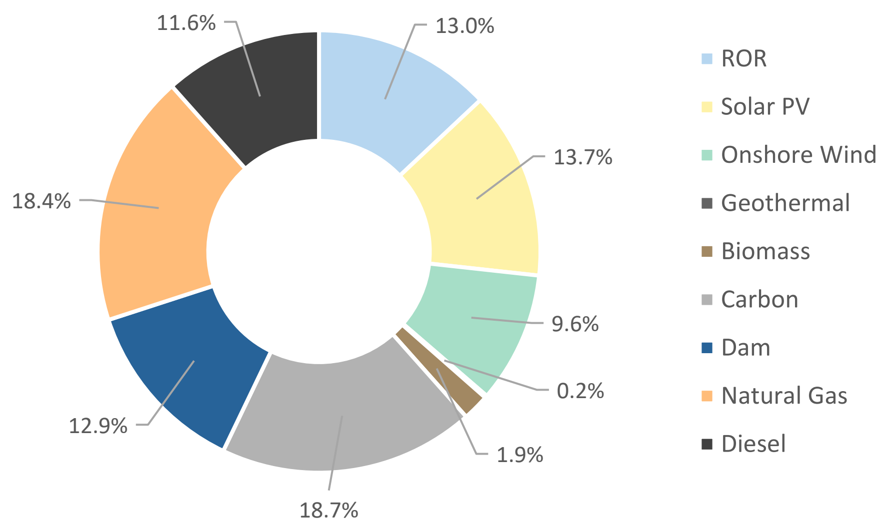
Figure 5 Historical generation of the SEN



Source: Own elaboration based on CEN

It can be observed from the figure above that the thermal generation is constant throughout the period, whereas the hydro, solar PV, and onshore wind technologies have a stational tendency that match the seasons with the highest amount of solar resource and the de-icing periods. It can also be seen that the solar PV technology has a growing tendency throughout the period, going from 4.975 GWh/year in 2018, to 6.290 GWh/year during 2019, and 7.609 GWh/year during 2020. The following figure shows the total installed capacity of the SEN by technology as of February 2021.

Figure 6 Installed capacity per technology



Source: Own elaboration based on CEN

The installed capacity of the SEN as of February 2021 totals 26,376 MW. Thermal installed capacity, counting coal, natural gas, and diesel technologies have a share of 48.7% of the total installed capacity of the SEN. Hydro powered units (run-of-river and dam units) add up to 25.9% of the total installed capacity, while solar PV and wind-based technologies represent 23.3% of the SEN's installed capacity.

The following table shows the installed capacity for the main generation companies nationwide.

Table 6 Installed capacity per generation company

Company		Installed capacity (MW)	Installed capacity (%)
ENEL		7,118	27.0%
AES Gener		3,558	13.5%
Colbún		3,217	12.2%
ENGIE		2,179	8.3%
Others	-	10,304	39.1%
Total		**26,376**	**100.0%**

Source: Generadoras de Chile

There is a big market concentration when considering the installed capacity of the SEN. The “big four” (Enel, AES Gener, Colbún, and Engie) own 60.9% of all the installed capacity of the SEN. However, given the increase in competitivity that has been seen during the last tendering processes for regulated and unregulated clients, the market share has diversified and permitted the entry of new competitors. This has also have had an impact on prices, as competitivity tends to lower prices, which is what has happened in the last years.

Regarding the transmission segment, the main company is Transelec, with 27.6% of the market share. CGE and Interchile come afterwards with 10.7% and 5.5%, respectively. The following table shows the tract kilometrage for lines of 66 kV, 110 kV, 220 kV, 500 kV, and total market share taking in consideration all transmission line kilometers, considering longitude and not number of circuits per tract.

Table 7 Transmission companies

Company	66 kV (Km)	110 kV (Km)	220 kV (Km)	500 kV (Km)	% Total kilometrage
TRANSELEC	463.7	544.8	6,212.0	1,339.0	27.6%
CGE	2,605.3	1,102.2	22.2	0.0	10.7%
INTERCHILE	0.0	0.0	442.6	1,509.2	5.5%
ENGIE	171.0	940.4	801.4	0.0	5.4%
COLBÚN TRANSMISIÓN	140.3	164.6	1,145.3	0.0	4.3%
MINERA ESCONDIDA	0.0	0.0	999.7	0.0	3.6%
AES GENER	14.4	181.6	621.4	0.0	3.4%
TEN	0.0	0.0	25.0	1,177.9	3.4%
CHILQUINTA	161.8	274.8	70.0	0.0	2.5%
STS	474.8	251.0	119.0	0.0	2.4%
ENEL TRANSMISIÓN CHILE	0.0	464.5	262.9	0.0	2.1%
OTHERS	1,058.7	2,088.3	5,835.6	720.8	29.1%

Source: Own elaboration based on CEN

As it can be seen, 11 companies concentrate 70.9% of the whole market share. In the remaining 29.1%, there are 176 additional companies, totalizing 187 transmission companies operating in the SEN. The following table shows market concentration per number of clients and sales in GWh for distribution companies.

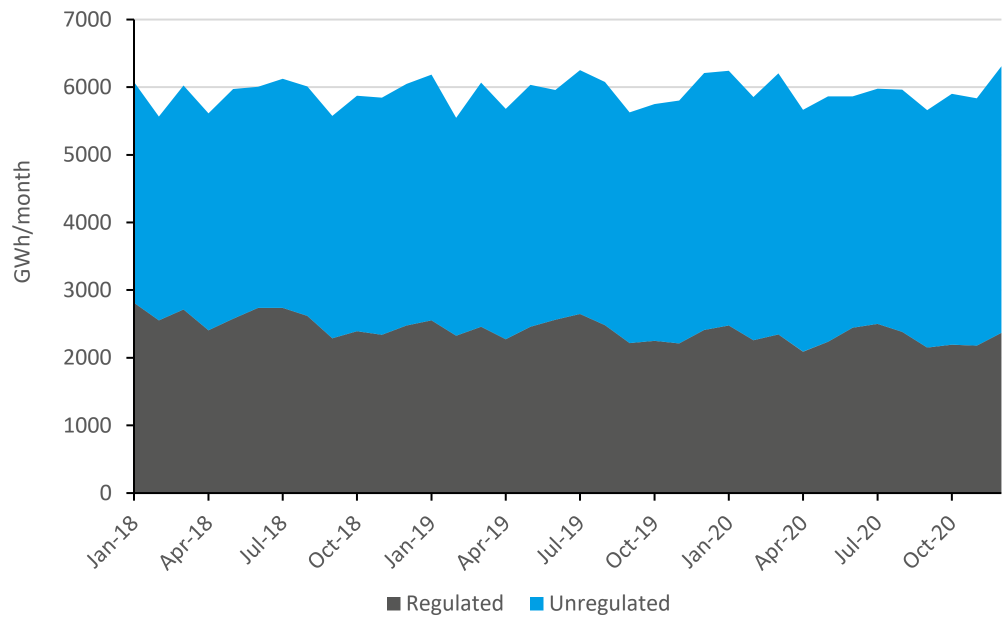
Table 8 Distribution companies

Group	Company	Distribution Region(s)	Clients (Dec-19)	% Clients	Energy Sales (Dec-19)	% Energy Sales
CGE	CGE	XV, I, II, III, IV, V, RM, VI, VII, VIII, IX	2,938,820	44.5%	11,156	31.7%
	Edelmag	XII	63,653	1.0%	318	0.9%
Chilquinta	Chilquinta Energía	V	611,889	9.3%	2,542	7.2%
	Litoral	V	63,233	1.0%	106	0.3%
	Energía de Casablanca	V y RM	6,401	0.1%	52	0.1%
	Luzlinares	VII	35,040	0.5%	107	0.3%
	Luz Parral	VII, VIII	25,694	0.4%	82	0.2%
Enel	Enel Distribución	RM	1,941,950	29.4%	16,999	48.4%
	Colina	RM	27,880	0.4%	98	0.3%
	Los Andes	RM	2,388	0.0%	9	0.0%
Saesa	Frontel	VIII, IX	365,747	5.5%	1,001	2.8%
	Saesa	IX, X, XIV	455,055	6.9%	2,351	6.7%
	Edelaysén	X, XI	48,528	0.7%	159	0.5%
	Luz Osorno	X, XIV	23,985	0.4%	158	0.4%

Source: Empresas Eléctricas A.G.

The most important company in terms of number of clients is CGE, with 44.5% of them, followed by Enel Distribución with 29.4% and Chilquinta Energía with a 9.3%. In between these three companies, 83.2% of the total clients of the SEN can be found. However, in terms of sales, the biggest company is Enel Distribución, with 48.4%, followed by CGE with 31.7% of the sales, and Chilquinta Energía, with 7.2%. However, it must be said that these are only regulated customers, and that there is a considerable amount of energy consumed by unregulated clients. The following figure shows the distribution between regulated and unregulated clients from January 2018 until December 2020.

Figure 7 Regulated and unregulated clients



Source: Own elaboration based on CEN

The figure shown above exposes that there has been a migration from regulated clients to the unregulated scheme, in the pursue of the access to more competitive and lower prices for their electric supply. This is evidenced in the reduction of 18.9% that the regulated scheme has suffered from January 2018 to December 2020.

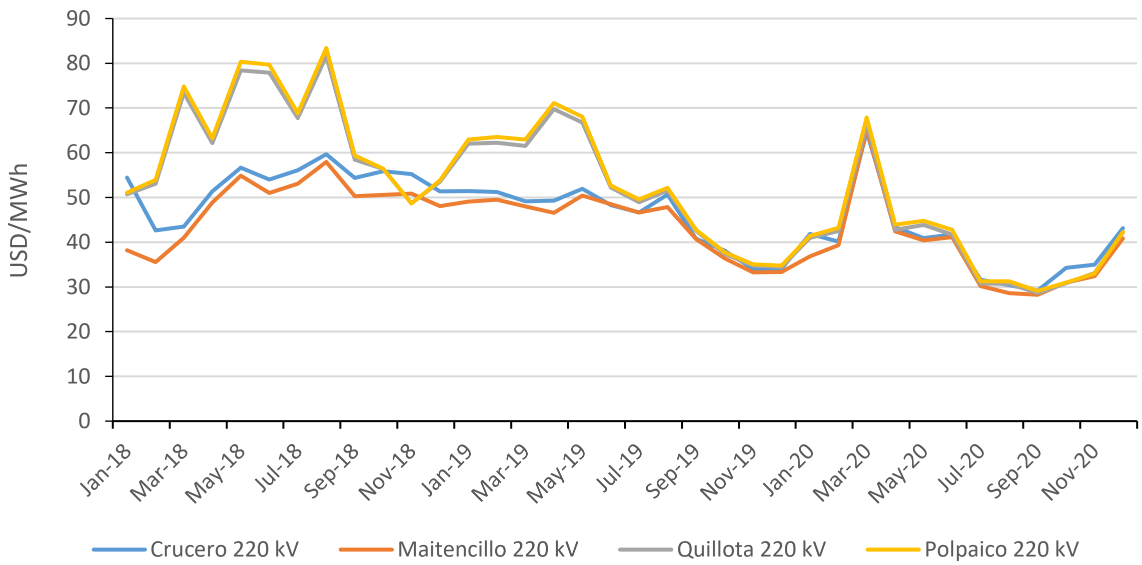
2.3.2 Historical Price Overview

The following section shows a revision of three topics mainly: spot price, capacity price, and ancillary services. The spot price revision is made in four representative nodes of the Northern and Central zones of the country, the capacity price revision oversees historical prices and regulation of the capacity market, and the ancillary services section shows the main regulatory aspects of the provision of said services along with historical data on prices per type of ancillary service.

2.3.2.1 Historical spot price

This section analyzes historical spot curves for representative nodes of the Northern and Central zones of the SEN. These nodes are Crucero 220 kV, Maitencillo 220 kV, Quillota 220 kV, and Polpaico 220 kV. The following figure shows monthly average prices for all four nodes from January 2018 until December 2020. This period is contemplated as the SEN was not interconnected before November 2017, and hence nodes were electrically and economically decoupled.

Figure 8 Historical marginal costs for representative nodes



Source: Own elaboration based on CEN.

As it can be seen, there is a stational tendency particularly in Central Zone nodes of higher marginal costs during autumn, from March to April. Furthermore, a decoupling can be seen between marginal costs for the Northern and Central Zones. However, this decoupling is partially solved during mid 2019 with the commissioning of the transmission line Cardones – Polpaico, which improved the transmission system. There is a decreasing tendency for all series analyzed that can be explained by the vertiginous insertion of NCRE units, particularly solar PV ones. The following table shows the yearly average of marginal costs for the nodes under analysis.

Table 9 Yearly average marginal costs

USD/MWh	Crucero 220 kV	Maitencillo 220 kV	Quillota 220 kV	Polpaico 220 kV
2018	53,0	48,4	63,6	64,6
2019	45,4	44,2	52,0	52,7
2020	39,7	38,1	39,5	40,2

Source: Own elaboration based on CEN

2.3.2.2 Historical capacity price

Supreme Decree 62 (DS 62) provides the computation formulas to obtain capacity injections and withdrawals, used to determine transfers within the generating units, which are valued at the capacity price.

DS 86 establishes that the CNE will calculate the basic capacity price in one or more national substations of the electrical system, depending on the number of subsystems that, for such purposes, it has defined. It also establishes that the CNE must determine the most cost-efficient generating technology to supply additional capacity during the hours of maximum annual demand in one or more main substations of the electrical system. The basic capacity price in each subsystem will be equal to the annual marginal cost of increasing the installed capacity of the subsystem with such technology, increased by a percentage equal to the theoretical capacity reserve margin of the respective subsystem. In addition, it establishes that the investment costs and fixed operating costs of the peak unit in the respective subsystems defined by the CNE will be determined based on a Study of the Costs of the Point Units for the respective electrical systems, in a period no longer than four years.

For the estimation of the capacity price in the basic capacity substations considered, the study "Determination of Investment Costs and Fixed Operating Costs of the Peak Unit, in SIC, SING and Medium Systems (SSMM); and determination of Investment Costs by Source of Generation" performed by the CEN in 2016 established that basic capacity price in the basic capacity substation (PBP) is determined with the following equation4:

$$Pbpot\left(\frac{\frac{\text{USD}}{\text{kW}}}{\text{month}}\right) = \left\{(C_{TG} \cdot FRC_{TG} + C_{SE} \cdot FRC_{SE} + C_{LT} \cdot FRC_{LT}) \cdot CF + C_{fijo}\right\} \cdot (1 + MRT) \cdot (1 + FP)$$

Where,

$Pbpot$: Basic Capacity Price (USD/kW/month).

C_{TG}: Unit investment cost of the project generating unit (USD/kW).

FRC_{TG}: Capital recovery factor of the generating unit. Corresponds to the monthly payment of the investment over a useful life of 25 years.

C_{SE}: Unit cost of the electrical substation of the project (USD/kW).

FRC_{SE}: Capital recovery factor of the electrical substation. Corresponds to the monthly payment of the investment over a useful life of 30 years.

[4] The 2016 report is used instead of the 2021 update as this report, published on March 2021, is still in a preliminary stage.

C_{LT}: Unit cost of the transmission line that connects the substation of the project to the National Transmission System (USD/kW).

FRC_{LT}: Capital recovery factor of the transmission line. Corresponds to the monthly payment of the investment over a useful life of 20 years.

CF: Financial cost.

C_{fijo}: Fixed cost of operation and maintenance (USD/kW).

$1 + MRT$: Increase by Margin of Theoretical Reserve.

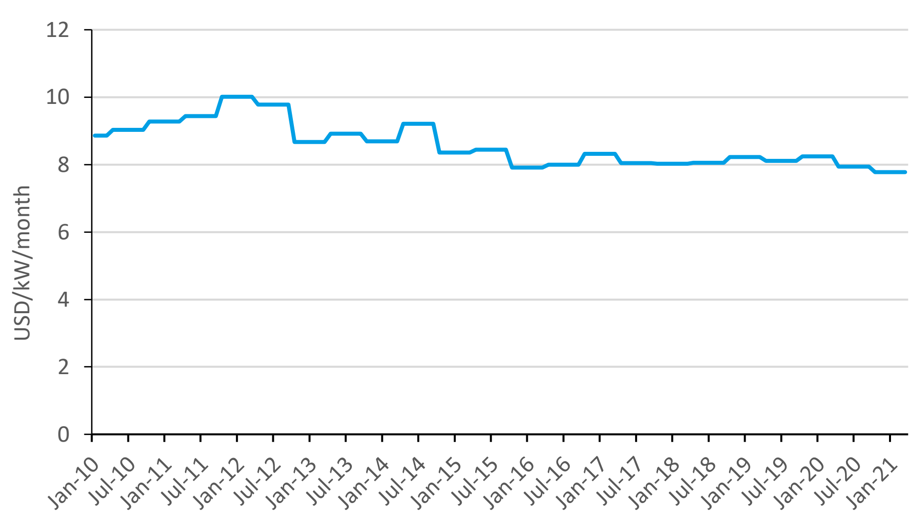
$1 + FP$: Increase by loss factor.

To estimate the capacity price at the node in which a generation unit is connected, the capacity price at a basic substation is required (the substation as reference for the capacity subsystem) and estimation of the capacity penalty factor at the node of interest. The multiplication of these two values gives the capacity price for each node of the system.

It should be noted that DS 86 establishes that both the short-term energy and capacity prices, set semiannually, will be readjusted when the price of capacity or energy resulting from applying the indexing formulas determined in the last biannual rate setting, experience a cumulative variation greater than ten percent.

The historical capacity price for Polpaico 220 kV is now revised. This information is obtained from the biannual ITD published by the CNE. The fixations occur every April and October of each year. The following figure shows the historical capacity price for Polpaico 220 kV from January 2010 until March 2021, in USD/kW/month.

Figure 9 Historical capacity price for Polpaico 220 kV



Source: Own elaboration based on CNE

As it can be seen, during the last decade capacity payments have been relatively stable, between 8 and 10 USD/kW/month. During the last three fixations a reduction of the capacity price has been seen, reaching a low peak during the last fixation period of 2020's second semester, of 7.78 USD/kW/month. This stability in power prices is observed in all nodes of the system.

2.3.2.3 Ancillary Services

The ancillary services actual regulation entered in operation at the beginning of 2020, incorporating market mechanisms in the allocation of these services. The current regulation is based in the Supreme Decree Nº113 of 2017, which approves the ancillary services dispositions. Despite this, the main elements to take in consideration from this are three:

- The instauration of market mechanisms for the allocation of some services
- The ability of the CNE to define services without the need of new laws being enacted (accelerating processes for possible future needs)
- The fact that services defined may not have been yet needed in the system.

The law defines that when there is a competitive market for a service available (which is declared in the Ancillary Services Report), it should be allocated and remunerated through a competitive market, being this market an auction system if they are short-term needs (when the presentation and delivery is separated by a time inferior to six months) or a tender process if they are long-term requirements.

For the moment, only short-term services (and only some of them) have been a competitive market, and therefore have a market system through which the services providers are allocated. In the case the CEN declares that a service has no competitive market, the allocation is defined by direct instruction of the CEN, and remuneration is related to covering the variable costs associated to delivering the service in question. Despite these broad guidelines for the allocation and remuneration mechanisms, each one of the services has individual characteristics, that will not be discussed in detail as it is beyond the scope of this report.

The main ancillary services presently defined are frequency control, voltage control, contingency control, and service recovery plan. Their subcategorization can be found in the following table.

Table 10 Ancillary services categorization

Ancillary Service	Categories	Subcategories
Frequency Control	Rapid Frequency Control (CRF)	CRF (+/-)
	Primary Frequency Control (CPF)	CPF (+)
		CPF (-)
	Secondary Frequency Control (CSF)	(CSF+)
		(CSF-)
	Tertiary Frequency Control (CTF)	(CTF+)
		(CTF-)
	Interruptible Demand (CI)	CI
Voltage Control	Voltage Control (CT)	CT
Contingency Control	Demand Disconnection	EDAC
		DMC
	Generation Disconnection	EDAG o ERAG
	Defense Plan against Contingencies (PDC)	Extreme PDC (PDCE)
		Critical PDC (PDCC)
Service Recovery Plan (PRS)	Autonomous start (PA)	PA
	Fast Isolation (AR)	AR
	Linking Infrastructure (EV)	EV

Source: Own elaboration based on CEN

As it was already mentioned, the CNE has the power to define new services if the CEN declares the necessity for them, avoiding the need to enact a new law. From all the services presented, only the CPF (-), CSF, and CTF have been found to have competitive markets and therefore are the only ones with a market allocation system, by auctions, for 2021. Currently, the rest of the ancillary services function under a mandatory and direct instruction from the CEN.

Despite the Ancillary Services defined above, not all are currently provided. The Rapid Frequency Control has been found not to be needed for the period 2021-2024, due to its substitutability with inertia in the system. This service will act as a countermeasure against rapid changes of frequency, replacing the inertia of synchronous machines.

Considering that the decarbonization process and the consequent disconnection of the coal plants will diminish the inertial response of the system, eventually the service is expected to be needed, but this point has not yet been reached. Anyhow, the study in which the CEN bases its results may have to reconsider some assumptions due to the rapid entrance of Variable Renewable Energy (VRE) sources making possible the CEN's reconsideration in the application of the CRF in the near future. This is relevant due to the suitability to supply this service with batteries, making it an alternative source of revenue for this type of technology. A hybrid project already proposed to deliver this type of service, but it was denied by the CEN as it does not see it economically beneficial for the system yet.

It is important to mention that the technology development, has allowed the entrance of VRE sources to compete in this market as well, therefore taking an active part as a solution of the problem imposed by their very own variability, and in maintaining the secure operation of the system. In the SEN there are already over 30 VRE generation plants that participate in the Voltage Control scheme and one VRE unit that has verification from the CEN to participate in the CSF: Luz del Norte. The maximum participation for this plant is 20 MW, a considerable amount considering that the national requirements for Secondary Frequency Control during 2021 are 130 MW, so it implies over 15% of the total reserves needed in this section.

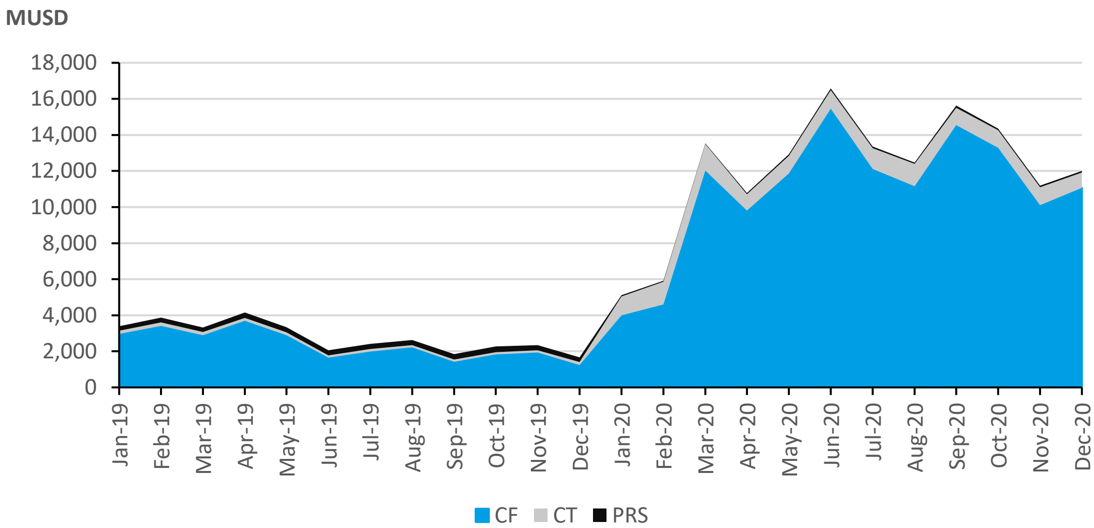
In Figure 10, the resulting costs separated by Ancillary Service can be observed. Two remarkable features can be seen, the first one being the preponderance of the cost spent in Frequency Control on the overall value, being around 88% of the costs associated to Ancillary Services. The second noticeable feature is the sudden increase in the Ancillary Services remunerations since the beginning of the year 2020. This is a consequence of the change in the regime, changing in 2020 to a market approach. This new regime has suffered certain difficulties due to auctions prices going up and auctions being declared deserted, therefore costs are expected to move downwards.

Considering the extreme change experienced during the last year in terms of total costs, it is difficult to predict the evolution of the market size for Ancillary Services. It will probably oscillate between the costs of 2019 and 2020, which were respectively of approximately 33 MM USD and 138 MM USD, considering that deserted auctions are paid at high prices. Anyway, it should be considered that there has been a huge expansion in costs associated to overruns (paid to units running when the marginal cost does not pay the variable cost of the unit), which expanded almost fivefold between those years, from around 14 MM USD to 68 MM USD. This is relevant because they are costs that have no critical relation with the results of the auctions.

The distribution of the remuneration received from the Ancillary Services between the main companies can be observed in Figure 11

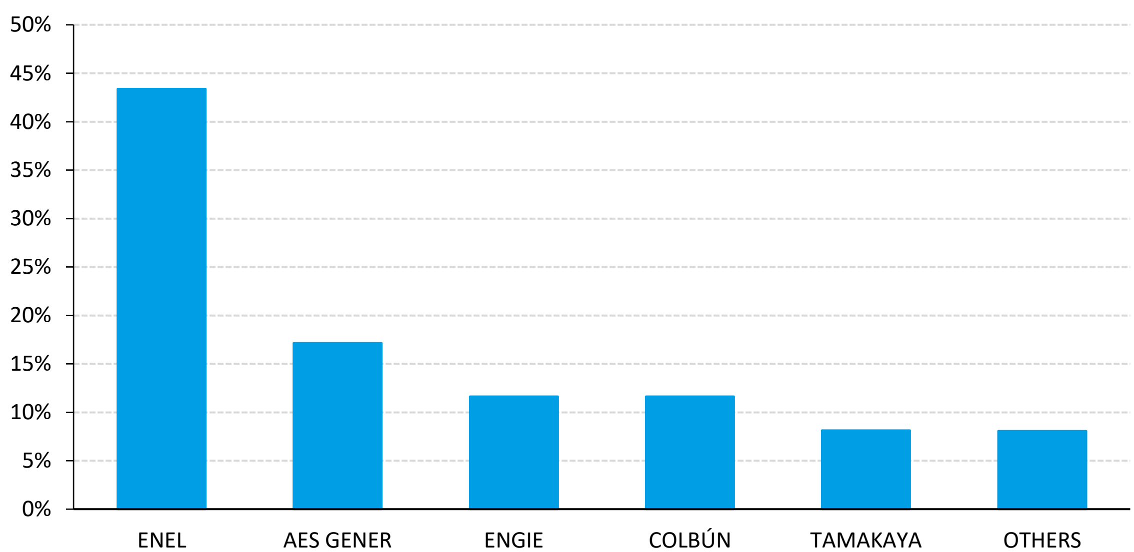
Figure 11. These services have mainly been supplied by the four largest companies of the generation segment (Enel, AES Gener, Colbún, and Engie). There is a noticeable participation of Tamakaya Energy, owner of the natural gas Kelar units.

Figure 10 Ancillary services costs grouped by service



Source: Own elaboration based on CEN

Figure 11 Ancillary services remuneration distribution by company



Source: Own elaboration based on CEN

2.4 Potential market changes

2.4.1 Modifications to the sufficiency capacity market

The Chilean electricity system is in a period of transformation or transition associated with a set of trends such as an increase in the participation of variable renewable generation sources, increasing participation of distributed generation, energy storage, among others.

To address this challenge, the Ministry of Energy developed a Flexibility Strategy to define a set of actions necessary to allow the development and use of the flexibility required in the National Electric System (SEN). Within the measures defined in the Strategy, one of the main suggested regulatory changes corresponds to improving the treatment of sufficiency capacity.

In this context, since October 8th, 2020, the Ministry of Energy has been developing a discussion process with representatives of associations, companies, consultants, and academics, for the modification of the capacity market. On December 30th, 2020, a "conceptual proposal" of the proposed change was share among the different representatives, requesting the actors to send their opinions no later than March 15th, 2021. In general, the proposal has been strongly questioned by most of the participants (among other questions, the “illegality” of the proposal has been raised). To date, the Ministry of Energy is defining the steps to follow, the discussion will probably return to an initial state of discussion on the “diagnosis” of the problems that are being solved.

From this perspective, although the current Minister of Energy has promised to have these modifications to the capacity market during the current year, given the political, health, and economic context (the presidential elections will be held in December 2021 and the change of government in March 2022), likely, the modifications that are being proposed will not reach to be published by the current administration.

However, the changes that are contemplated can be summarized as follows:

- Incorporation of a new concept of “Flexible Capacity” to satisfy the needs of the flexibility of the system (NFS), concerning the ramps of the system, measured in MWh. Specifically, the modification would introduce a new element to define the definitive capacity of a unit, called “sufficiency capacity”. In this way, the payment for the capacity of a unit would depend on its ability to contribute both sufficiency capacity and flexibility, so the current calculation for the different generation units would change significantly.
- Incorporation of modifications that integrate better “demand signals” for the determination and contribution to the sufficiency power. Fundamentally in this regard, a

control schedule will be established considering the hours of greatest stress for the system based on its reliability.

- Introduction of changes to the recognition of the supply in the market of sufficiency capacity, incorporating a probabilistic methodology for the recognition of the contribution of the facilities, without the need to define a particular methodology for each technology.
- Changes in the definition of subsystems; modification of the Theoretical Reserve Margin (MRT); treatment of the forced unavailability index (IFOR); and establishing a target reliability level.

According to the analysis presented by the Ministry of Energy, the aforementioned modifications would have an impact on a solar plant that would be 50% compared to the current standard. In the case of wind power, it is more variable since it depends on the location and the wind resource, some could benefit and others not.

2.4.2 Treatment of power plant dispatch based on liquified natural gas

In the case of Chile, LNG is a fuel that, by its nature, presents physical and logistical restrictions in terms of transportation, regasification, and storage. These restrictions are the ones that generate the "inflexibility" condition defined in the current LNG Technical Regulation, according to which the companies that own LNG-based plants have recognized the possibility of signing flexible gas supply contracts (with the possibility of diverting the shipment to other markets) or inflexible ("take or pay" type). In the latter case, the regulation establishes that their marginal cost is "zero", so they are dispatched first on the merit order considered as base in the system.

This situation has generated two main problems: higher levels of inflexible gas in periods of an abundance of variable renewable resources have implied the curtailment of solar and wind generation in certain nodes of the system. Likewise, the marginal cost would not be reflecting the corresponding price level, since, as indicated, inflexible gas is declared at a marginal cost equal to “zero” (since the opportunity cost is to burn that gas without an alternative use).

For this reason, the CNE has prepared a draft of the "Conceptual Proposal" for the modification of the corresponding technical regulation, the purpose of which would be that the declaration of inflexibility is exceptional so that the electrical system has power plants that operate with LNG flexibly and economically.

The CNE proposes that the inflexibility condition should be exceptionally used as a last resource by the LNG Companies, which would be activated under requirements that must be met by said companies as established by the GNL technical normative, considering a binding study prepared by the CEN, which would define the maximum volume of said fuel that companies could request in a condition of inflexibility.

Based on this analysis, the process would be as follows:

1. Study of Projection of Generation of LNG Units by CEN.
2. Annual delivery program (ADP) by companies. The LNG Company has two alternatives: a) Nominate in the respective ADP several vessels less than or equal to that indicated in the LNG Study; b) Nominate in the respective ADP several vessels greater than that indicated in the LNG Study. Only those companies that opted for alternative a) will have the possibility that their LNG volumes can be declared in a condition of inflexibility.
3. Ships included in ADP.
4. Avoidable inflexibility condition (it occurs six weeks before the arrival of the corresponding ship, and if a lesser use of Gas is projected, the clauses that could allow the ships to be diverted should be used).
5. Condition of inflexibility.

The “new” LNG Study to be carried out by the CEN would begin in 2021 onwards. In this way, LNG Companies whose contracts do not have all the flexibility clauses will apply these requirements to supply from 2023 onwards. Otherwise, the rule would apply from 2021.

As we have pointed out, the proposal is in a draft state and has been questioned both by the CEN and by the companies that own LNG-based plants. In the Consultant’s opinion, it requires further analysis in its development, since it could discourage the contracting of LNG, which could create safety risks in the operation and increase marginal costs, especially in dry hydrology scenarios.

Notwithstanding the above, if this new regulation is approved, the Consultant estimates it could have a positive effect on the income that would be obtained in the business model that the client is negotiating, since on the one hand, it reduces the probability of curtailment of variable renewable energy, such as likewise, it would tend to raise marginal costs, if diesel plants begin to be dispatched instead of gas that has not been contracted by companies.

2.5 Impact of the Pandemic on the Chilean Electricity Market

The effects of the pandemic in the Chilean electricity market can be seen in two main aspects. On one hand there is a variation in electricity consumption and on the other it can be seen in delays in construction of electrical infrastructure.

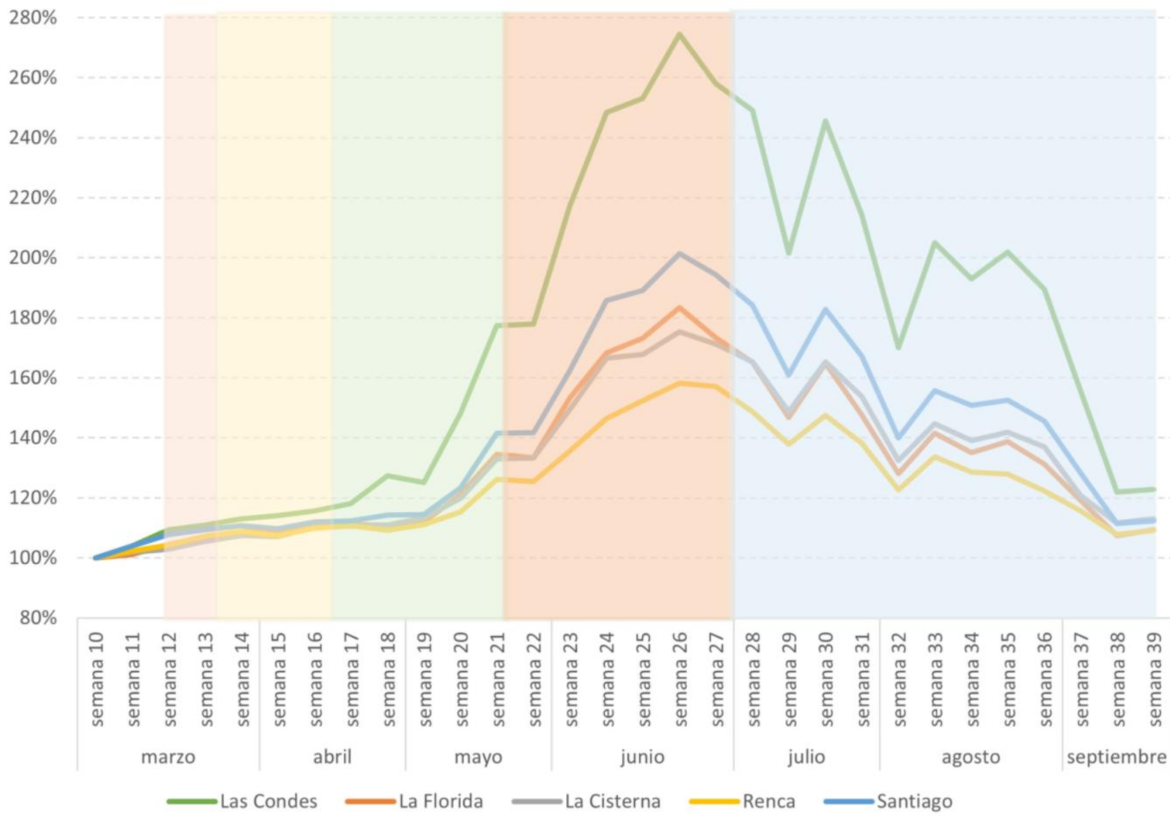
2.5.1 Energy Consumption

One of the aspects that has been affected by the pandemic in Chile is the demand for electricity. Electricity consumption in the country is divided into two groups, regulated clients and free clients, where the first group corresponds to a mainly residential, commerce or small industry consumption and the second industrial one. Given that they have different consumption profiles it is better to analyze them separately.

With respect to regulated clients, it was noted that confinement increased residential consumption considerably, especially in communes with higher incomes, but following a generalized increase. [5] Figure 12Figure 12 shows the impact of confinement on residential consumption. Quarantines begin in the green strip and the closing of schools in the orange strip. The blue band corresponds to the relaxation of some confinement measures. It can be noticed that the final value is still 10-20% higher. This cycle of consumption is expected to be repeated each time quarantine or other measures return. On the other hand, changes were also noted in the daily hourly distribution of consumption.

[5] MORENO, Rodrigo, et al. Impactos del COVID-19 en el Consumo Eléctrico Chileno. Revista Ingenierıa de Sistemas Volumen XXXIV, 2020.

Figure 12 Percentage increase in residential demand compared to the first week of the pandemic

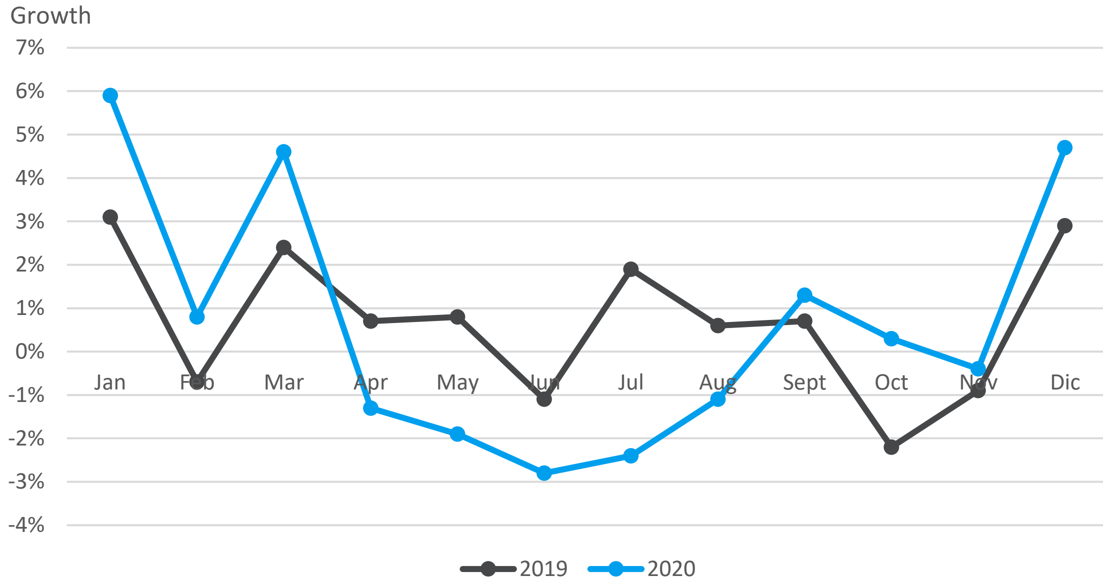


Source: *Impactos del COVID-19 en el Consumo Eléctrico Chileno*.[6]

Regarding the demand from free customers, a slowdown in the increase in demand was noted. Between the months of April and August 2020, there was a negative demand growth. Previous years are not compared due to regulatory changes that distort the signal. Figure 13 shows a graph with the growth in the demand of free customers month by month for the years 2019 and 2020, an effect of the pandemic is noted when the confinement measures began to take effect, generating a decrease in the growth of demand. It can also be noticed a drop in October 2019, this is attributed to the social unrest that occurred in the country during that time.

[6] MORENO, Rodrigo, et al. Impactos del COVID-19 en el Consumo Eléctrico Chileno. Revista Ingeniería de Sistemas Volumen XXXIV, 2020.

Figure 13 Increase in the demand of free clients for the years 2019 and 2020



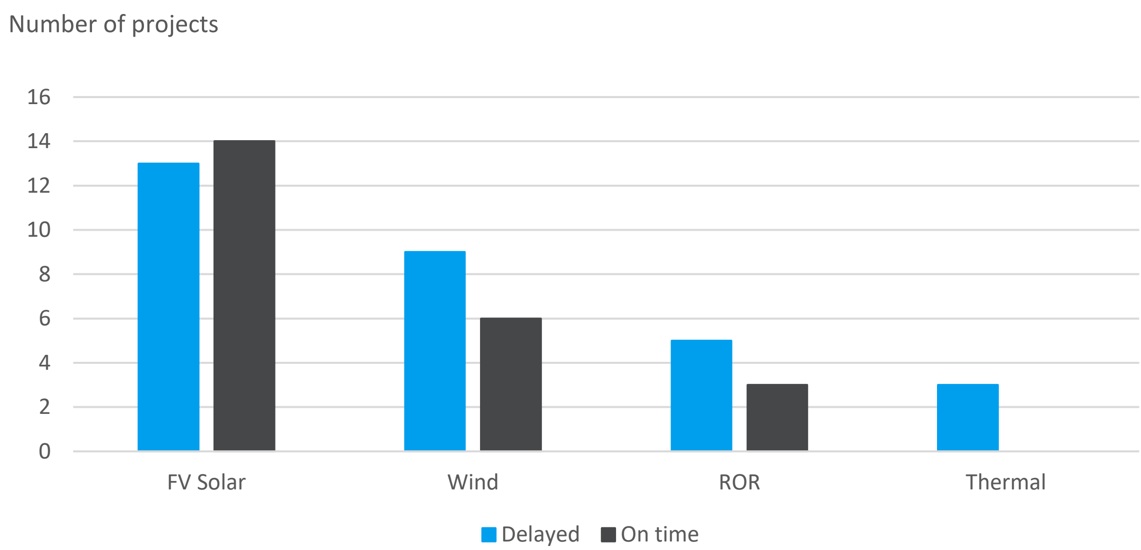
Source: Own elaboration, based on Coordinator data

2.5.2 Delays on electrical infrastructure

Another area in which an effect of the pandemic has been noticed is in the construction of electrical infrastructure. Either within the generation, transmission or distribution segment, there have been delays in projects declared under construction and also in future projects.

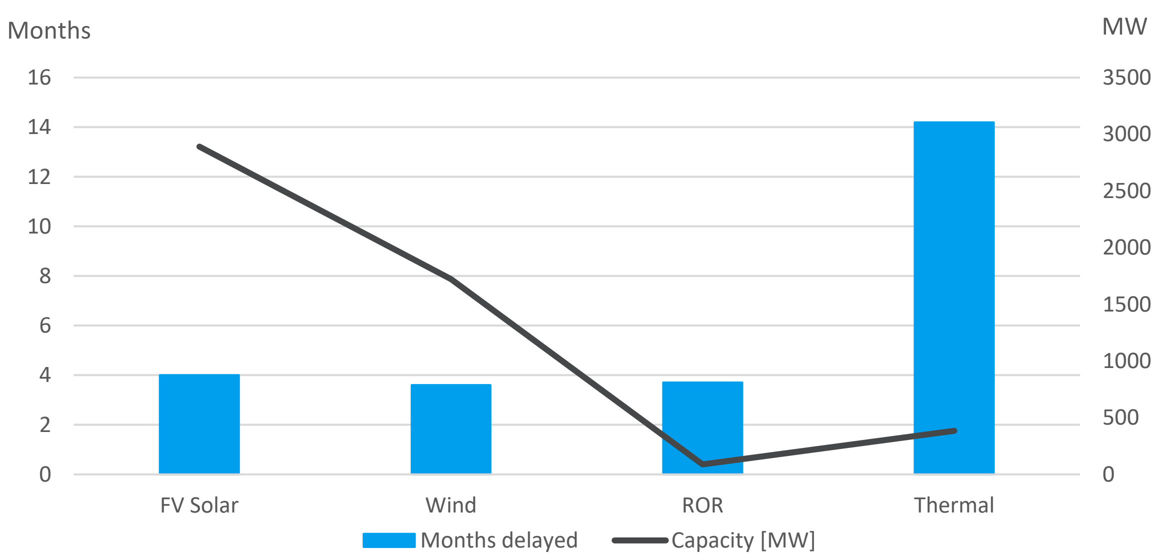
There has been a delay in the construction of generation projects across the country. Of about 5,000 MW of generation declared under construction, currently almost 2,800 MW have delays, corresponding to 55% of the projects. Figure 14 makes a comparison between the number of generation projects, currently under construction, that present delays in the works and those that do not. It can be seen that in general more than half of the projects are behind schedule. Then, in Figure 15 the average number of months of delay that each technology has and also the capacity under construction can be seen. The largest capacity currently under construction corresponds to solar plants, and these are 4 months behind on average. On the other hand, thermal plants are on average more than 14 months late in their construction.

Figure 14 Number of generation projects delayed and on time for every technology



Source: Own elaboration, based on Coordinator data

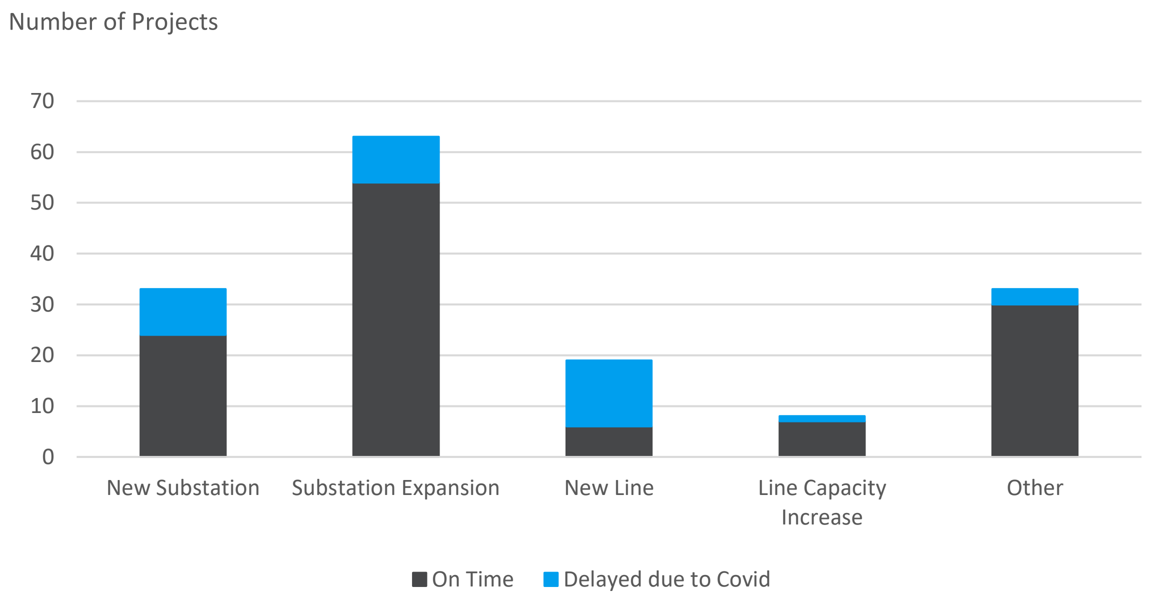
Figure 15 Average generation project delay in months and sum for capacity under construction by technology



Source: Own elaboration, based on Coordinator data

Regarding electrical infrastructure projects, these have also been affected by the pandemic. Although, in general, several projects do not present major delays, there are some that are behind the initial schedule for reasons directly related to the pandemic. Figure 16 shows the projects that have a declared delay due to covid-19. It can be noted that the type of project that has been most affected is the construction of new lines.

Figure 16 Electrical infrastructure projects with delays due to covid-19



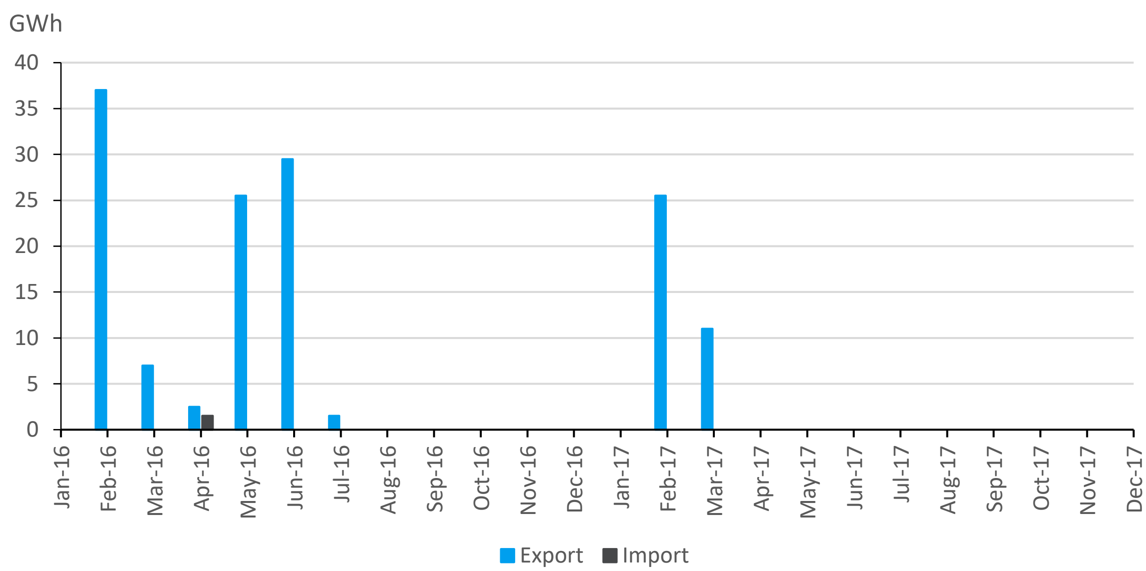
Source: Own elaboration, based on Coordinator data

2.6 Electricity Export Market

To date, Chile only has one international interconnection line. It is the Andes-Salta line, located in the north of the country, at approximately the same latitude as the city of Antofagasta. The interconnection was made on February 12, 2016.

Exports were only recorded in 2016 and 2017, with respect to imports they were only recorded in April 2016, since April 2017 there have been no exports or imports. In total, around 134 GWh have been exported since the interconnection of the line, what could be considered insignificant at the scale of the complete system. In 2016 exports corresponded to 0.14% of the total generation of the system. Figure 17 shows the monthly exports and imports that have taken place since the interconnection.

Figure 17 Energy exports and imports



Source: Own elaboration, based on coordinator data

International transfers of electrical services are established in the General Law of Electrical Services, specifically these are allowed in article 78 of the aforementioned document. Within the legislation, two types of national interconnection facilities are considered:

1. Public service international interconnection facilities: those that facilitate the formation or development of an international electricity market and complement the supply of the electricity system demand in the national territory, in the face of different scenarios of availability of generation facilities, including contingency and failure situations,

considering quality requirements and service security established in this law, the regulations and technical standards.

2. International interconnection facilities of private interest: those that do not meet the characteristics indicated in the previous point.

The General Law of Electrical Services establishes that the regulation of international exchanges of electrical services will be regulated from Decree 142, which sets the requirements and procedure applicable to requests for international exchanges of electrical services. This decree establishes that:

- The Coordinator will be responsible for the coordination of the technical and economic operation of the International Interconnection Systems.
- The safety and quality of service requirements to which the planning and operation of the export and import of energy and other electrical services must be subject will be those established in the current regulations.
- The expansion, development, remuneration and payment of the International Interconnection Systems will be governed by the provisions contained in articles 78 and 99 bis of the General Law of Electrical Services and in the other regulations in force.

3 Market Perspective, Methodology, and Assumptions

This chapter describes the main input data corresponding to the Base Scenario and the methodologies on which the projection of commercial revenues and costs are based. These data correspond to generation and transmission expansion plans, a decarbonization plan, fuel price projection, LNG availability and demand projection. In addition, methodological aspects related to energy marginal cost projection, capacity recognition projection.

The Base Scenario was prepared considering assumptions of future development that are deemed as representative and plausible, according to the available information contained in different relevant sources of the electricity sector, and it considers a decarbonization plan consisting of coal power plant decommissioning schedule.

Among the information used can be mentioned: January 2021 Nodal Price Final Technical Report, developed by the National Energy Commission, in its most recent version available at the beginning date of the study; public information of National Electrical Coordinator; and relevant electricity market information, in addition to the Consultant's criteria and experience.

3.1 SDDP model and energy marginal cost projection

The methodology adopted for projecting the monthly average marginal costs uses the Stochastic Dual Dynamic Programming (SDDP) model as its main element.

The SDDP model optimizes and simulates the operation of a multi-node and multi-reservoir hydrothermal system, with treatment of the hydrological uncertainty in water inflows to reservoirs and inflows to run-of-river power plants. Additionally, it incorporates a representation of the transmission system. Currently, the Consultant uses the latest version of the software SDDP.

The SDDP model calculates the operating policy that minimizes the expected cost of operation for a hydrothermal system, considering, among others, the following aspects:

- Thermal power plants: efficiency, specific consumption, minimum and maximum generation capacity.
- Hydroelectric plants including their reservoirs and operating features.
- The hydrological features of the system as represented by the hydrological statistics and uncertainty of tributary water courses.
- Transmission system: direct current power flow model, transmission capacity per facility, and transmission losses.

- Monthly stages with demand blocks in order to capture the demand's level variability in a working day and a non-working day. Also, demand blocks are used to capture hours with solar and hours without solar PV generation.

An important assumption in the projection of marginal costs is the future development of the electrical system, which is used as input data for the SDDP model. The main assumptions correspond to a generation expansion plan, a transmission system expansion plan, a projection of fuel prices and a projection of the demand of the system. The main assumptions will be explained in more details in the following sections.

From the simulation carried out by the model, it is possible to obtain expected average marginal cost projections for the nodes of interest for every monthly stage, from April 2021 to December 2040. In addition, given that several demand blocks per month were used, average monthly marginal cost projections for each block were obtained. This is particularly relevant given the possibility of obtaining marginal cost projections with solar photovoltaic generation, as well as marginal cost projections without solar photovoltaic generation.

It is also important to bear in mind that given the characteristics of the hydrothermal power systems operation projection, such as the National Electrical System, the marginal cost projection is not a deterministic activity, because depends on the evolution of variables involved in the electrical system, which are complex to determine or estimate with a high level of certainty. Therefore, it is necessary to establish that the projections are associated exclusively to the best possible estimates for these variables, with the model characteristics and the assumptions used.

3.2 Capacity recognition projection

In the Chilean electricity market, payments for capacity is an incentive to promote system adequacy. In Chile, the capacity recognition for power plants is called "Adequacy Capacity" (Potencia de Suficiencia).

To obtain an Adequacy Capacity projection of the units of interest recognized by the National Electrical Coordinator, a methodology based on the applicable provisions for the Adequacy Capacity of a generating unit calculation was used. These provisions correspond to those contained in Supreme Decree 62 of 2006, as amended by Supreme Decree 44 of 2007, Supreme Decree 130 of 2011, and Supreme Decree N° 42 of 2020, which establishes the regulation for the transfer of capacity between generation companies; and the provisions contained in the technical standard for the transfer of capacity between generation companies, of 2016.

Supreme Decree 62 provides that capacity transfers between generating companies are determined based on the generation capacity compatible with the adequacy (Adequacy Capacity) and the existing peak demand commitments assigned to each power plant.

Supreme Decree 62 defines **Capacity Adequacy** as the capacity of a system or subsystem to supply the peak demand. Likewise, it defines that Peak Demand corresponds to the average demand of the 52 higher hourly demands of the annual load curve for each system or subsystem (the capacity subsystems are those identified in the technical reports of the nodal prices). Also, it defines **Adequacy Capacity** as the capacity that a generating unit contributes to the capacity adequacy of the system or subsystem.

In order to determine the Adequacy Capacity of a generating unit, it is necessary calculate its Initial Capacity and its Preliminary Adequacy Capacity.

Supreme Decree 62 establishes that the **Initial Capacity** of a generating unit is less than or equal to its Maximum Capacity and characterizes the capacity that the unit can contribute to the system based on the uncertainty associated with the availability of its primary energy, which the generating unit can operate continuously for a Maximum Capacity.

Regarding the Adequacy Capacity for a wind project, it is necessary to calculate the initial capacity in order to obtain the final adequacy capacity. Therefore, the Initial Capacity (IC) is calculated as it follows:

$$IC = MIN(CF_{annual}; CF_{52\ hours})$$

Where,
CF_{annual}: Lower capacity factor in the last 5 years prior to the year of calculation.
$CF_{52\ hours}$: Simple average of the capacity factors at each of the 52 bigger hourly values of the system or subsystem load curve; in the year of calculation.

However, this method only works for already built projects. For new projects, statistical information for similar units is used.

Once the Initial Capacity of all the generating units of the system or subsystem have been obtained, the **Preliminary Adequacy Capacity** of a generating unit is determined from:

i. Initial Capacity of all generating units of the system or subsystem reduced by their maintenance factors and self-consumptions.
ii. Forced Outage rate of the generating unit.
iii. Peak demand of the system or subsystem.

The maintenance factor of a generating unit corresponds to a factor proportional to the major maintenance period. It is important to mention that, if the maintenance is carried out within the periods established in the major maintenance program in force at the beginning of the year, the statistics of the forced outage rate are not affected. On the other hand, if the maintenance is carried out in a term longer than the established, the difference will affect the statistics of the forced outage rate. Likewise, if the maintenance is carried out in a term shorter than the scheduled, only the period effectively used is counted for the maintenance factor.

The Forced Outage rate of a generating unit is determined based on the time the unit was in operation and the time it was unavailable, during all the hours of 5 consecutive years. This parameter is determined as follows:

$$FO = \frac{T_{OFF}}{T_{ON} + T_{OFF}}$$

Where,

T_{OFF}: Accumulated time in which the unit was unavailable, either by forced or programmed disconnection for 5 years. It considers accumulated time in maintenance periods that exceed the period of major maintenance in force at the beginning of each year.

T_{ON}: Accumulated time in which the unit was in operation, independent of the dispatch level, for 5 year.

The Forced Outage rate includes events in which the unit is not available due to the facilities unavailability that connect it to the transmission or distribution system, also, in the case of hydroelectric power plants, hydraulic facilities unavailability is attributed to Forced Outage rate. Thus, the Preliminary Adequacy Capacity (PAC) is defined as it follows.

$$PAC = IC * (1 - FO)$$

Finally, for each generating unit, the definitive Adequacy Capacity corresponds to the Preliminary Adequacy Capacity escalated by a single factor for all generating units so that the sum of the definitive Adequacy Capacity of the units is equal to the Peak Demand. The definite Adequacy Capacity is then calculated as follows:

$$Adequacy\ Capacity_{\ i} = PAC_i \cdot \frac{D_{Peak}}{\sum_i PAC_i}$$

Where,

PAC_i: Preliminary Adequacy Capacity of generating unit "i" (MW).
D_{Peak}: Peak demand of the System or Subsystem (MW).

It is important to note that, in the case that capacity subsystems are identified, the Preliminary and Definitive Adequacy Capacity of each generating unit and for each subsystem must be calculated, considering the Peak Demand of each subsystem plus the capacity transmitted between the subsystems.

Regarding the capacity price, the Supreme Decree 62 provides that capacity injections and withdrawals must be valued at the capacity nodal price. The capacity nodal price projection was made considering the most recent Short-Term Nodal Price Technical Report at the beginning date of this study and the report "Determination of Investment Costs and Fixed Operating Costs of the Peak Unit, in the systems SIC, SING and SSMM; and determination of Investment Costs by Source of Generation" of the year 2016.

Adequacy Capacity projections of the power plants of interest and capacity nodal price projections were obtained until December 2034. For subsequent years of this horizon, projections were made based on the trends obtained for the last years of projection.

3.3 Generation expansion plan

The expansion plan considers in the short and medium term power plants projects that belong to companies that have been awarded regulated PPA in public tender processes for regulated customers, and projects that are under construction or have a high certainty of being built. Capacity has been adjusted in order to match the final awarded energy per company in the tender process. Beyond year 2026, the expansion plan considers new renewable power plants, based on technology development costs, and strategic locations in order to fulfill future energy demands in the national system.

The following table shows the generation expansion plan, where power plants currently in testing period are indicated by (*):

Table 11 Generation expansion plan

Generation Expansion Plan					
CoD Date	Power Plant	Capacity (MW)	Technology	Developer/Owner	Comments
May-21	Solar Usya(*)	52	Solar PV	Acciona	PPA with DisCos
May-21	Pajonales (*)	100	Diesel	Prime Energy	Backup Unit

Generation Expansion Plan					
CoD Date	**Power Plant**	**Capacity (MW)**	**Technology**	**Developer/Owner**	**Comments**
May-21	San Pedro Solar(*)	106	Solar PV	GPG SOLAR CHILE SpA	PPA with DisCos
May-21	Cabo Leones II (*)	204	Wind	Ibereólica	PPA with DisCos
May-21	Solar Quillahua	100	Solar PV	Greenergy	
May-21	Renaico 1	88	Wind		
Jun-21	Combarbalá	75	Diesel	Prime Energy	Backup Unit
Jun-21	Parque FV Atacama Solar	150	Solar PV	Sonnedix	PPA with DisCos
Jun-21	Cerro Pabellon (U3)	30	Geothermal	Enel Green Power	
Jun-21	La Huella	84	Solar PV	Clean Capital Energy	
Jun-21	Malleco eólica (Etapa I)	135	Wind	WPD	PPA with DisCos
Jun-21	Negrete (Etapa I)	36	Wind	WPD	PPA with DisCos
Jun-21	Rio Escondido	150	Solar PV	Mainstrean Energy	PPA with DisCos
Jun-21	Malgarida (Etapa I)	28	Solar PV	Acciona	PPA with DisCos
Jul-21	CSP Cerro Dominador	110	CSP	Cerro Dominador CSP SA	PPA with DisCos
Jul-21	Azabache (*)	61	Solar PV	Enel Green Power	
Jul-21	Malleco eólica (Etapa II)	138	Wind	WPD	PPA with DisCos
Jul-21	La Estrella	50	Wind	OPDE Energy	PPA with DisCos
Aug-21	San Javier etapa 1	25	Diesel	Prime Energy	Backup Unit
Sep-21	Cabo Leones III (*)	268	Wind	Ibereólica	PPA with DisCos
Sep-21	San Javier etapa 2	25	Diesel	Prime Energy	Backup Unit
Sep-21	Alena	84	Wind	Mainstrean Energy	PPA with DisCos
Sep-21	Los Olmos	100	Wind	Aes Gener	
Sep-21	Eólico Calama	150	Wind	Engie	
Sep-21	Cerro Tigre Eólica (Etapa I)	185	Wind	Mainstrean Energy	PPA with DisCos
Oct-21	Central de respaldo Maitencillo	70	Diesel	Empresa Eléctrica Vallenar S.A.	Backup Unit
Oct-21	Llanos Blancos	150	Diesel	Prime Energy	Backup Unit
Oct-21	Tchamma Eólica	155	Wind	Mainstrean Energy	PPA with DisCos
Oct-21	Finis Terrae II	126	Solar PV	Enel Green Power	
Oct-21	Cabo Leones 1 (extensión)	175	Wind	EDF y Ibereólica	PPA with DisCos
Nov-21	La Cruz	50	Solar PV	Xelio Chile	
Nov-21	FV Capricornio	88	Solar PV	Engie	
Nov-21	Tamaya	114	Solar PV	Engie	
Nov-21	MAPA	160	Biomass	Arauco	
Dec-21	Valle del Sol	150	Solar PV	Enel Green Power	
Dec-21	Sol de Lila	152	Solar PV	Enel Green Power	
Jan-22	Renaico 2	232	Wind	Enel Green Power	
Jan-22	Malgarida (Etapa II)	163	Solar PV	Acciona	PPA with DisCos
Jan-22	Santa Isabel I	159	Solar PV	Total Energy	
Jan-22	Lomas de Duqueco	59	Wind	WPD	PPA with DisCos
Jan-22	Campo del Sol	399	Solar PV	Enel Green Power	
Jan-22	Puelche Sur	156	Wind	Mainstrean Energy	PPA with DisCos
Jan-22	Meseta de los Andes	120	Solar PV	Sonnedix	PPA with DisCos
Jan-22	Domeyko	186	Solar PV	Enel Green Power	
Jan-22	El Sol de Vallenar (Etapa I)	35	Solar PV	Cox Energy	PPA with DisCos
Jan-22	Las Lajas	267	ROR	Aes Gener	PPA with Non-regulated Customer

Generation Expansion Plan					
CoD Date	Power Plant	Capacity (MW)	Technology	Developer/Owner	Comments
Feb-22	Coya FV	180	Solar PV	Solventus	
Feb-22	Mesamávida	60	Wind	Aes Gener	
May-22	Valle Escondido	100	Solar PV	Mainstrean Energy	PPA with DisCos
May-22	Pampa Tigre	100	Solar PV	Mainstrean Energy	PPA with DisCos
May-22	Llanos del viento	156	Wind	Mainstrean Energy	PPA with DisCos
Jun-22	Sol del desierto	175	Solar PV	Mainstrean Energy	PPA with DisCos
Jun-22	Ckani Eólica (Etapa I)	110	Wind	Mainstrean Energy	PPA with DisCos
Jun-22	Alfalfal II	264	ROR	Aes Gener	PPA with Non-regulated Customer
Jun-22	CEME (Etapa I)	140	Solar PV		
Jul-22	Sol del desierto 2	55	Solar PV	Atlas Energy	
Jul-22	Caman Eólica (Etapa I)	165	Wind	Mainstrean Energy	PPA with DisCos
Nov-22	Sol de Andes	89	Solar PV	Austrian Solar	
Jan-23	Willka	98	Solar PV		
Jan-23	Campo Lindo	100	Wind	Aes Gener	
Jan-23	Horizonte (Etapa I)	170	Wind	Colbún	
Jan-23	Sol del desierto	230	Solar PV		
Aug-23	Sol de Atacama	81	Solar PV	Austrian Solar	
Aug-23	Sol de Varas	101	Solar PV	Austrian Solar	
Jan-24	Parque eólico Punta de Talca	86	Wind	Atacama Energy	PPA with DisCos
Jan-24	Hidroeléctrica VIII Región 02	20	ROR		
Jan-24	Hidroeléctrica VIII Región 04	20	ROR		
Jan-24	San Rarinco	150	Wind	FRV	PPA with DisCos
Jan-24	Parque solar Punta del viento	130	Solar PV	FRV	PPA with DisCos
Feb-24	Los Cóndores	150	ROR	Enel Green Power	
Jun-24	Horizonte (Etapa II)	340	Wind	Colbún	
Dec-24	Horizonte (Etapa III)	510	Wind	Colbún	
Jan-25	Sol de Vallenar (Etapa II)	97	Solar PV	Cox Energy	PPA with DisCos
Jan-25	Hidroeléctrica VIII Región 05	20	ROR		
Jan-25	CEME (Etapa II)	350	Solar PV	Generadora Metropolitana	PPA with DisCos. Replacement of El Campesino (Agreed with CNE).
Jan-26	Hidroeléctrica VIII Región 06	20	ROR		
Jan-26	CTA (cambio de tecnología)	175	Biomass	Engie	
Jan-26	CTH (cambio de tecnología)	175	Biomass	Engie	
Jan-26	IEM (cambio de tecnología)	370	LNG	Engie	
Sep-28	San Pedro	144	ROR	Colbún	
Jan-29	Hidroeléctrica VIII Región 07	20	ROR		
Jul-29	Solar Maitencillo 1	150	Solar PV		
Jan-30	Eólica Puerto Montt	50	Wind		
Jan-30	Ñuble	136	ROR		
Jan-31	Eólica Parinacota 2	150	Wind		
Jan-31	Hidroeléctrica VIII Región 08	20	ROR		
Jan-31	Solar Punta Color	200	Solar PV		
Jan-31	Eólica Pelambre	200	Wind		
Jul-31	Solar Lagunas	100	Wind		

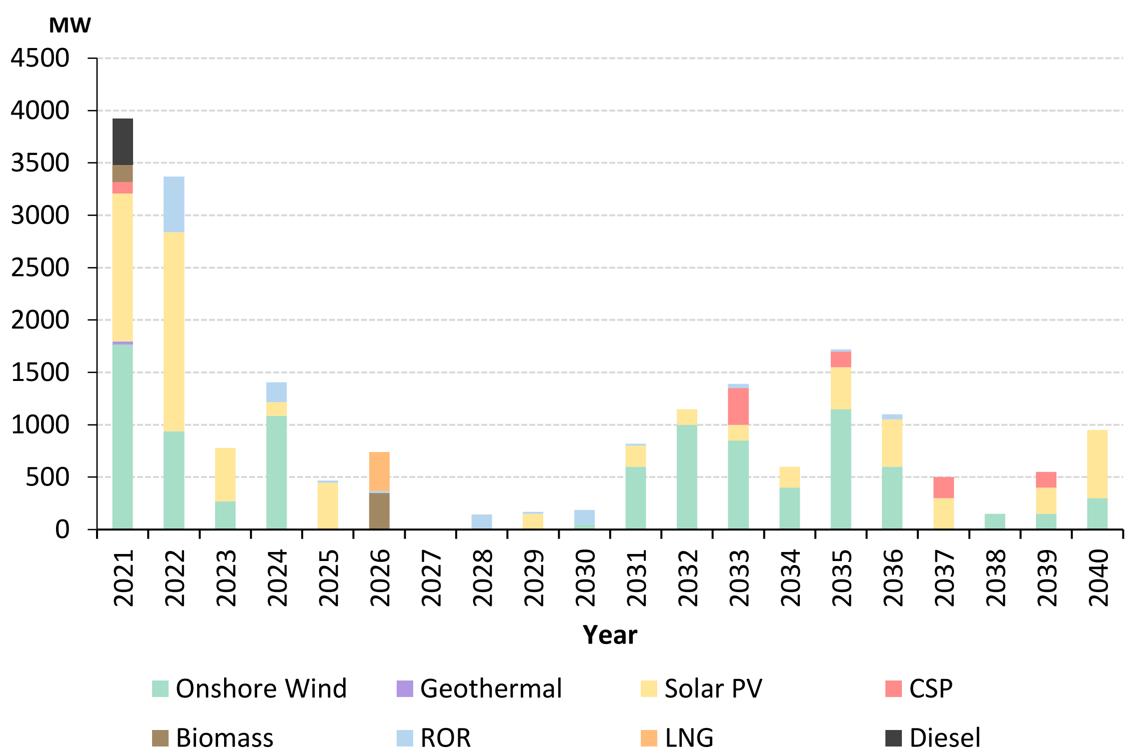
Generation Expansion Plan					
CoD Date	Power Plant	Capacity (MW)	Technology	Developer/Owner	Comments
Jul-31	Eólica Concepción	150	Wind		
Jan-32	Eólica Concepción 2	100	Wind		
Jan-32	Eólica Maitencillo	150	Wind		
Jan-32	Eólica Charrúa 4	250	Wind		
Jan-32	Eólica Cumbres 2	200	Wind		
Jan-32	Eólica Cumbres 2	150	Wind		
Jan-32	Eólica Chiloe	150	Wind		
Jan-32	Solar Diego de Almagro 2	150	Solar PV		
Jan-33	CSP Kimal 2	200	CSP		
Jan-33	Eólica Capricornio	150	Wind		
Jan-33	Eólica Mulchen	200	Wind		
Jan-33	Eólica Los Vilos 3	200	Wind		
Jan-33	Hidroeléctrica VIII Región 09	40	ROR		
Jan-33	Eólica Pan de Azúcar 3	150	Wind		
Jan-33	Solar Maitencillo 2	150	Solar PV		
Jan-33	Eólica V Región 3	150	Wind		
Feb-33	CSP Kimal 2	150	CSP		
Jan-34	Solar Los Cóndores	200	Solar PV		
Jan-34	Eólica San Vicente	200	Wind		
Jan-34	Eólica Hualpén	200	Wind		
Jan-35	Solar Maitencillo	200	Solar PV		
Jan-35	CSP Kimal	150	CSP		
Jan-35	Eólica Punta Sierra 2	200	Wind		
Jan-35	Hidroeléctrica VIII Región 10	20	ROR		
Jan-35	Eólica Mapal 2	200	Wind		
Jan-35	Eólica RM	150	Wind		
Jan-35	Eólica Rapel	200	Wind		
Jan-35	Solar Kimal	200	Solar PV		
Jan-35	Eólica Rapel	200	Wind		
Jul-35	Eólica Pan de Azúcar 3	200	Wind		
Jan-36	Eólica Rapel 2	200	Wind		
Jan-36	Los Vilos	200	Solar PV		
Feb-36	Eólica Kimal	200	Wind		
Jul-36	Solar Cardones 1	250	Solar PV		
Jul-36	Eólica Charrúa 4	200	Wind		
Sep-36	Hidroeléctrica VIII RegionC	50	ROR		
Jan-37	Solar Polpaico	300	Solar PV		
Jan-37	CSP Changos	200	CSP		
Jan-38	Eólica Charrua B	150	Wind		
Jan-39	CSP Lagunas	150	CSP		
Jan-39	Solar Lagunas 2	250	Solar PV		
Jan-39	Eólica Parinacota 2	150	Wind		
Jan-40	Eólica Gaby	150	Wind		
Jan-40	Pan de Azúcar	200	Solar PV		
Jan-40	Eólica Charrúa 4	150	Wind		
Jul-40	Solar Zaldívar	150	Solar PV		

Generation Expansion Plan					
CoD Date	Power Plant	Capacity (MW)	Technology	Developer/Owner	Comments
Jul-40	Solar Parinacota	200	Solar PV		
Jul-40	Eólica Atacama	100	Solar PV		

Source:CNE, CEN, Valgesta

Figure 18 shows a summary of the previous table grouping the capacity to be installed by technology each year.

Figure 18 Annual installed capacity by technology up to 2040



Sources: National Energy Commission, National Electrical Coordinator, Valgesta

3.4 Retirement of coal units

In the last years, the Chilean electricity market and its authorities have been adopting actions to facilitate the growth and participation of renewable energy.

In this context, the last actions of the government aim to decarbonize the energy matrix, in order to produce energy with less CO2 emissions each year. To achieve this goal, the government -in agreement with generation companies- set a decarbonization route, in which they indicate the year and the coal units that will stop producing energy. Nevertheless, the essence of this decommissioning schedule is not binding.

To converge with the Chilean regulation, the Base Scenario includes a decarbonization plan consisting of coal power plants decommissioning, which has been developed taking into account several aspects. Among the variables considered the following elements were evaluated: power plant's age, maintain security standards on system operation, reduction of the greenhouse gases by fulfilling the Chilean commitments in the Paris Agreement, local social impacts and restrictions of active PPA's that are associated to coal power plants.

The retirement plant for coal units is shown in the following table.

Table 12 Decarbonization plan

#	Owner	Powe Plant	Capacity	Decommissioning date
1	Engie	U13	87	out
2	Engie	U12	86	out
3	Enel	CTTAR	148	out
4	Aes Gener	Ventanas 1	120	out
5	Enel	Bocamina	130	out
6	Engie	U14	136	dic-21
7	Engie	U15	132	dic-21
8	Aes Gener	Ventanas 2	208	dic-21
9	Enel	Bocamina II	350	dic-21
10	Engie	CTM1	155	dic-23
11	Engie	CTM2	164	dic-23
19	Andina	CTA	175	dic-24
20	Hornitos	CTH	170	dic-24
28	Engie	IEM	375	dic-24
12	Aes Gener	NTO1	140	dic-25
13	Aes Gener	NTO2	136	dic-25
14	Guacolda	Guacolda U1	152	dic-26
15	Guacolda	Guacolda U2	152	dic-26

16	Guacolda	Guacolda U3	152	dic-27
17	Guacolda	Guacolda U4	152	dic-27
18	Aes Gener	Nueva Ventanas	272	dic-28
21	Guacolda	Guacolda U5	152	dic-29
22	Colbún	Santa María	370	dic-30
23	Angamos	ANG1	277	dic-31
24	Angamos	ANG2	281	dic-32
25	Aes Gener	Campiche	272	dic-33
26	Cochrane	CCH1	275	dic-34
27	Cochrane	CCH2	275	dic-34

Source: Valgesta

3.5 National Transmission expansion plan

In relation to the National Transmission works plan, the available public information is used. The state of progress of the upgrade and new projects under construction is considered based on CNE reports. Finally, for the long term, projected works are incorporated according to the detected requirements of the system, driven mainly because of possible future restrictions. The following table shows the National transmission expansion plan.

Table 13 Transmission expansion plan

Transmission Expansion Plan		
CoD Date	Project	Capacity (MVA)
Jul-21	New Line Pichirropulli - Puerto Montt 2x500 kV, energized in 220 kV	2x1500
Feb-22	New Line Nueva Pozo Almonte - Cóndores 2x220 kV: first circuit	1x260
Feb-22	New Line Nueva Pozo Almonte - Parinacota 2x220 kV: first circuit	1x260
Apr-22	New Line Maitencillo - Punta Colorada - Pan de Azúcar 2x220 kV	2x500
Nov-22	New Line Nueva Chuquicamata - Calama 2x220 kV	1x260
Nov-22	New Line Pan de Azúcar - Punta Sierra 2x220 kV	2x580
Nov-22	New Line Punta Sierra - Pelambres 2x220 kV	2x580
Nov-23	Capacity Increase Line Cautín - Ciruelos 2x220 kV	2x420
Jul-23	New Line Puerto Montt - Nueva Ancud y new air crossing 2x500 kV	2x1500
Jun-23	New Line Itahue - Mataquito 2x220 kV	2x485
Jul-24	Capacity increase Line Alto Jahuel - Lo Aguirre 2x500 kV	2x3000
Aug-24	New Line Nueva Alto Melipilla – Nueva Casablanca – La Pólvora – Agua Santa 2X220 kV	2x500
Aug-24	New Line Mataquito – Nueva Nirivilo – Nueva Cauquenes – Dichato – Hualqui 2X220 kV	2x485
Jul-24	Capacity increase Line La Cebada - Punta Sierra 2x220 kV	2x560
Jul-24	Second circuit laying Line Nueva Chuquicamata - Calama 2x220 kV (second circuit)	1x260
Jan-25	Capacity increase Line Frontera - María Elena 2x220 kV and María Elena - Kimal 2x220 kV	2x550

Transmission Expansion Plan		
CoD Date	**Project**	**Capacity (MVA)**
Jan-25	Capacity increase Line Charrua - Temuco 1x220 kV	1x530
Jan-25	New Line Parinas - Likanantai 2x500 kV	2x1700
Jun-28	New Line HVDC Kimal - Lo Aguirre	3000 (MW)
Jan-30	Energization in 500 kV of Line Pichirropulli - Puerto Montt 2x500 kV	2X1700
Jan-30	New Line Entre Ríos - Ciruelos 2x500 kV, energized in 220 kV	2x1700
Jan-30	New Line Ciruelos - Pichirropulli 2x500 kV, energized in 220 kV	2x1700
Jan-30	New Line Illapa - Cumbres 1x220 kV	1x400
Jan-30	New Line Changos - Cumbres 1x500 kV	1x1.500
Jan-32	New Line Pan de Azúcar - Polpaico 1x500 kV	1x1.500
Jan-32	New Line Rapel - Melipilla 1x220 kV	1x290
Jan-33	New Line El Tesoro - Esperanza 1x220 kV	1x190
Jan-33	New Line Charrúa - Ancoa 1x500 kV	1x1.500
Jan-33	New Line Ancoa - Alto Jahuel 1x500 kV	1x1.500
Jan-34	New Line Encuentro - Lagunas 1x220 kV	1x290
Jan-34	New Line Kimal - Changos 1x500 kV	1x1500
Jan-35	New Line Charrua - JMA 1x220 kV	1x650
Jan-35	New Line Atacama - Esmeralda 1x220 kV	1x290
Jan-35	New Line Laberinto - El Cobre 1x220 kV	1x360
Jan-35	New Line HVDC Kimal - Lo Aguirre	3000 (MW)

3.6 Fuel price projection

The following tables and figures show price projections for coal, WTI crude oil, and Liquefied Natural Gas (LNG). These projections are based on price projection from the report Annual Energy Outlook 2021 (AEO2020), developed by Energy Information Administration (EIA), updated to CPI of February 2021.

The projections for the price of coal in Chile were determined from the application of the methodology used by the National Energy Commission, which considers freight charges, marine insurance, waste, import tariff, customs agent, unloading, sampling and analysis. These charges were obtained from the “Informe de proyecciones de precios de combustibles 2021-2035”, of December 2020.

In relation to the projected price for natural gas in Chile, the projection corresponds to 115% of the projection of the natural gas price in Henry Hub, obtained from the AEO2020 report, plus 3.5 US$/MMBtu for liquefaction, transportation and regasification.

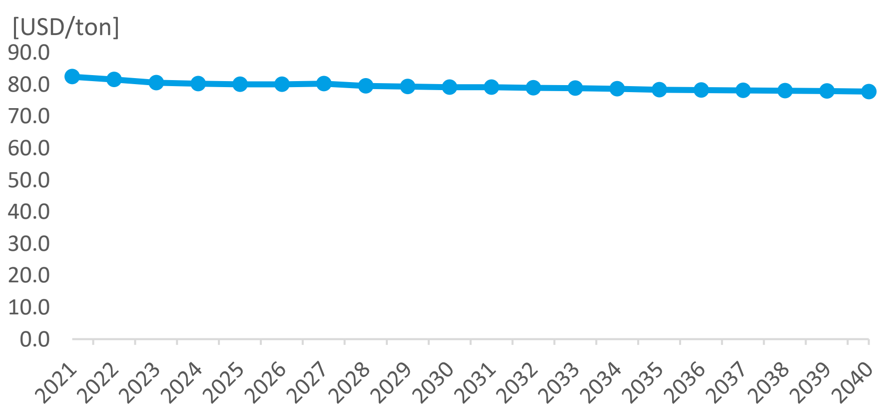
3.6.1 Coal Price

Table 14 Coal price projection

Year	Price [USD/Ton]
2021	82.4
2022	81.5
2023	80.5
2024	80.3
2025	80.0
2026	80.0
2027	80.2
2028	79.6
2029	79.3
2030	79.1
2031	79.1
2032	78.9
2033	78.8
2034	78.6
2035	78.3
2036	78.2
2037	78.1
2038	78.0
2039	77.9
2040	77.8

Source: EIA, CNE, Valgesta

Figure 19 Coal price projection



Source: EIA, CNE, Valgesta

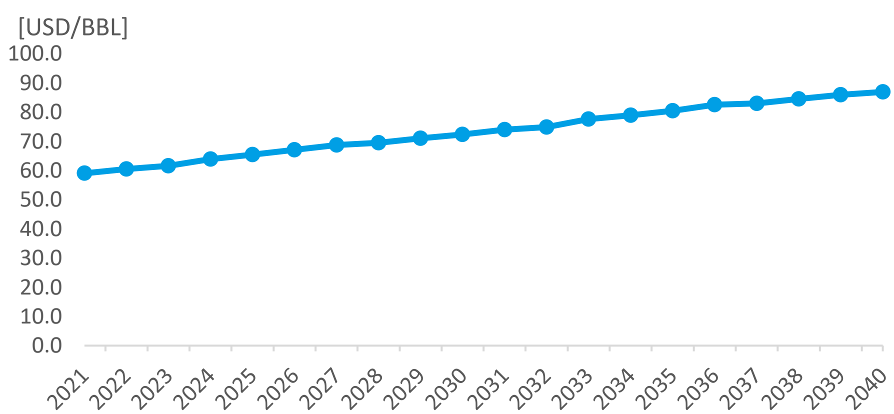
3.6.2 WTI crude price

Table 15 WTI crude price projection

Year	Price [USD/BBL]
2021	59.0
2022	60.5
2023	61.6
2024	63.9
2025	65.4
2026	67.1
2027	68.7
2028	69.5
2029	71.0
2030	72.3
2031	74.0
2032	74.9
2033	77.6
2034	78.9
2035	80.4
2036	82.5
2037	82.9
2038	84.5
2039	85.9
2040	86.9

Source: EIA, Valgesta

Figure 20 WTI crude price projection



Source: EIA, Valgesta

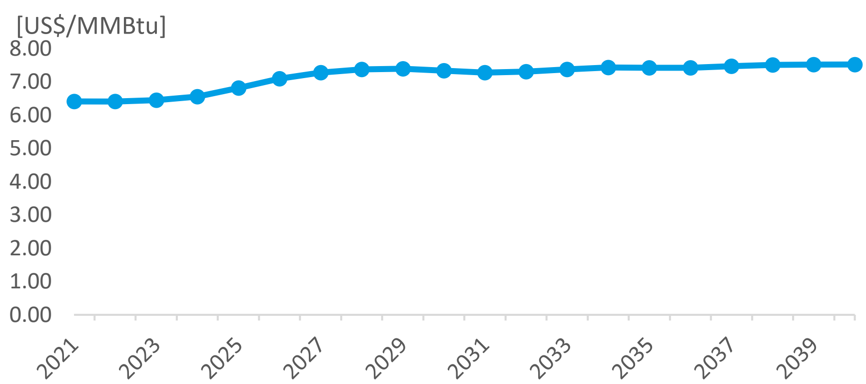
3.6.3 LNG price

Table 16 LNG price projection

Year	Price (US$/MMBtu)
2021	6.41
2022	6.40
2023	6.44
2024	6.55
2025	6.81
2026	7.09
2027	7.27
2028	7.37
2029	7.38
2030	7.33
2031	7.28
2032	7.30
2033	7.37
2034	7.43
2035	7.42
2036	7.41
2037	7.47
2038	7.50
2039	7.51
2040	7.52

Source: EIA, Valgesta

Figure 21 LNG price projection



Source: EIA, Valgesta

3.7 LNG availability projection

The projected availability of LNG for the generating plants of the National Electric System was determined on the basis of information contained in the Definitive Technical Report of the Short-Term Node Prices of July 2021 (published by CNE), public information of the National Electric Coordinator and Consultant's criteria. Values used are shown in Table 17.

Table 17 LNG availability projection

Unit	From	To	Availability
Taltal 1 y 2 CA	Mar-21	Dec-29	0%
	Jan-30	Dec-40	90%
Nehuenco 1 y 2	Mar-21	Dec-40	(*)
San Isidro 1 y 2	Mar-21	Dec-35	90%
Nueva Renca CC	Mar-21	Dec-24	25%
	Jan-25	Dec-30	50%
	Jan-31	Dec-40	90%
Candelaria 1 y 2 CA	Mar-21	Dec-29	0%
	Jan-30	Dec-40	90%
Quintero 1 y 2 CA	Mar-21	Dec-29	0%
	Jan-30	Dec-40	90%
CTM3	Mar-21	Dec-30	50%
	Jan-31	Dec-40	90%
Kelar CC 1 y 2	Mar-21	Dec-40	90%
U16	Mar-21	Dec-30	50%
	Jan-31	Dec-40	90%
Atacama (CC1 y CC2)	Mar-21	Dec-24	0%
	Jan-25	Dec-30	50%
	Jan-31	Dec-40	90%

(*) The availability of natural gas for the Nehuenco 1 and 2 plants, as of January 2021, corresponds to 90% from January to June and 50% from July to December.

Sources: CNE, CEN, Valgesta

3.8 Energy demand projection

3.8.1 Demand projection for the Base Scenario

The energy demand projection is based on actual demand data from 2020 and growth rates presented in the Final Technical Report for Short Term Nodal Prices of January 2021.

Table 18 National system energy demand projection – Base Scenario

Demand Forecast		
Year	Total (GWh)	Growth %
2020	71,808	
2021	74,516	3.77%
2022	78,393	5.20%
2023	81,206	3.59%
2024	84,990	4.66%
2025	87,084	2.46%
2026	90,242	3.63%
2027	93,140	3.21%
2028	93,802	0.71%
2029	94,676	0.93%
2030	95,511	0.88%
2031	96,613	1.15%
2032	98,334	1.78%
2033	100,066	1.76%
2034	101,845	1.78%
2035	102,717	0.86%
2036	103,982	1.23%
2037	105,479	1.44%
2038	107,278	1.71%
2039	109,342	1.92%
2040	112,040	2.47%

Sources: Valgesta

3.8.2 Demand projection for the downside sensitivity scenario

In addition to the Base Scenario, marginal cost projections are also obtained for a downside scenario that is characterized by lower annual growth rates for demand. Specifically, the assumed average demand growth in the period 2021-2030 in the downside scenario is 1.20%, substantially lower than the 2.90% for the Base Scenario. The average growth rate in the longer term, from 2031 to 2040, shows a moderate difference being 1.50% in the downside scenario and 1.61% in the Base Scenario.

Table 19 National system energy demand projection – Downside case

Demand Forecast		
Year	Total (GWh)	Growth %
2020	71,808	
2021	72,526	1.00%
2022	73,976	2.00%
2023	74,716	1.00%
2024	76,210	2.00%
2025	76,973	1.00%
2026	77,742	1.00%
2027	78,520	1.00%
2028	79,305	1.00%
2029	80,098	1.00%
2030	80,899	1.00%
2031	82,112	1.50%
2032	83,344	1.50%
2033	84.594	1.50%
2034	85,863	1.50%
2035	87.151	1.50%
2036	88,458	1.50%
2037	89,785	1.50%
2038	91,132	1.50%
2039	92,499	1.50%
2040	93,887	1.50%

Sources: Valgesta

3.9 Demand Block Construction

Regarding the demand representation for each stage, in this case monthly stages, the demand for an electrical system within each month can show significant variations in hourly instantaneous consumption levels. Therefore, modeling the demand of a stage/month as a single demand block is not representative of the reality. It is common, when solving hydrothermal coordination problems, that the demand of each month is represented through a set of demand blocks to represent variations during the day. Each demand block aggregates the consumption of several hours to capture the variability in demand during the day.

For this study, twelve demand blocks per month have been used, six blocks to capture the level demand variability in a working day, from Monday to Friday, as shown in Table 20, and six blocks to capture the level demand variability in a non-working day for Saturday, Sunday and holidays (Table 21). Additionally, each group of six blocks have 3 blocks with solar PV generation (where solar photovoltaic power plants can generate electricity), and 3 blocks without solar PV generation (where solar photovoltaic power plants cannot generate electricity).

The following tables show the hours comprising each demand block of a working day and non-working day.

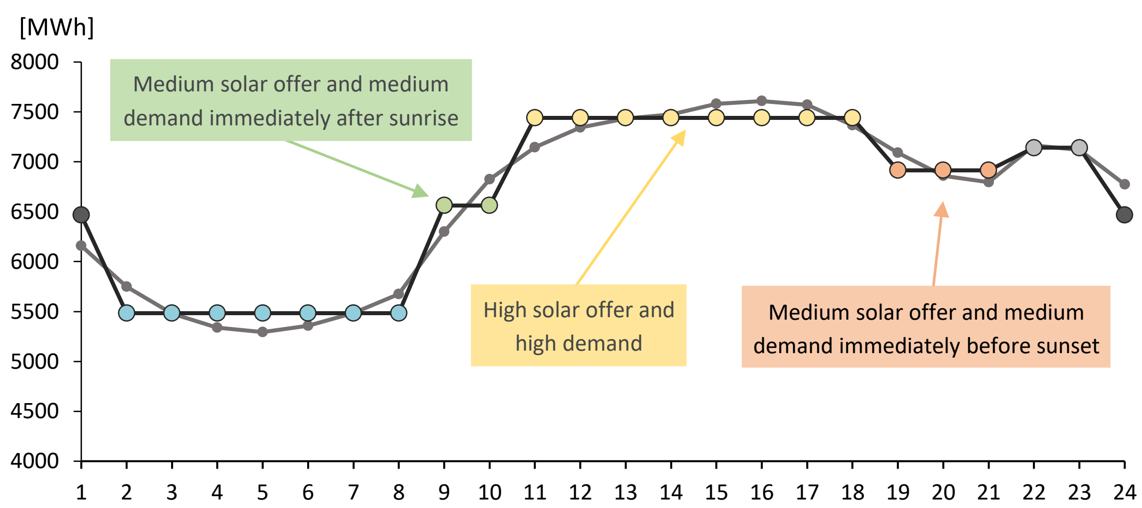
Table 20 Hours comprising each demand block of a working day

Month	Hour																						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	5	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	3	6	6	5
Feb	5	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	6	6	6	5
Mar	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	2	3	3	6	6	5	5
Apr	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	5	6	6	5	5
May	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	6	6	6	5	5
Jun	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	6	6	6	6	5	5
Jul	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	6	6	6	6	5	5
Aug	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	6	6	6	5	5
Sep	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	5	6	6	5	5
Oct	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	3	3	3	6	6	5	5
Nov	5	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	2	3	3	6	6	6	5
Dec	4	4	4	4	4	4	4	1	1	2	2	2	2	2	2	2	2	2	3	3	5	6	6	5

Table 21 Hours comprising each demand block of a non-working day

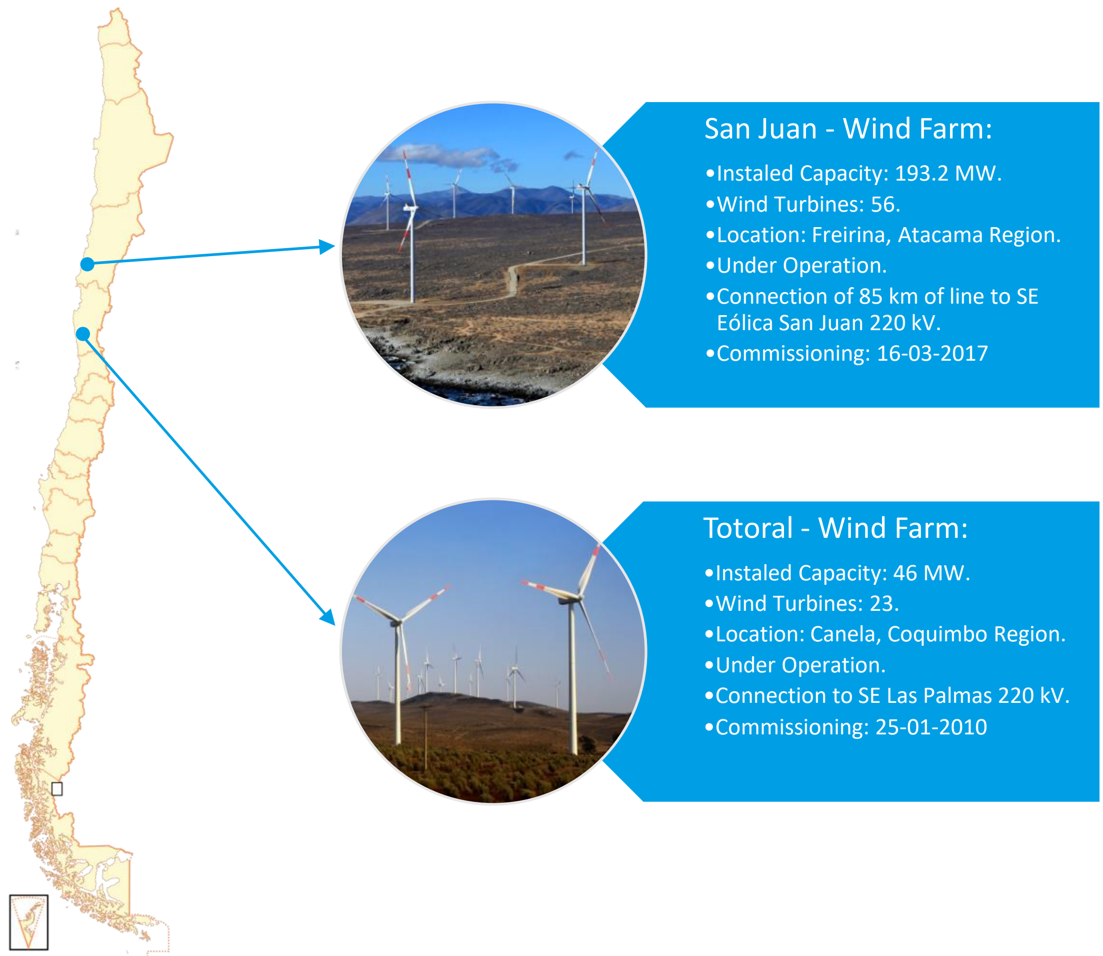
Month	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	11	11	10	10	10	10	10	10	7	7	8	8	8	8	8	8	8	8	9	9	9	12	12	11
Feb	11	11	10	10	10	10	10	10	7	7	8	8	8	8	8	8	8	8	9	9	11	12	12	11
Mar	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	8	9	9	9	12	12	12	11
Apr	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	8	9	9	11	12	12	11	11
May	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	8	8	9	12	12	12	11	11
Jun	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	8	9	12	12	12	12	11	11
Jul	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	9	9	12	12	12	12	11	11
Aug	11	10	10	10	10	10	10	10	10	7	7	8	8	8	8	8	9	9	9	12	12	12	12	11
Sep	11	11	10	10	10	10	10	10	10	7	8	8	8	8	8	8	9	9	9	11	12	12	12	11
Oct	11	10	10	10	10	10	10	10	7	7	8	8	8	8	8	8	9	9	9	9	12	12	12	11
Nov	11	11	10	10	10	10	10	10	7	7	8	8	8	8	8	8	9	9	9	9	12	12	12	11
Dec	11	11	10	10	10	10	10	10	7	7	8	8	8	8	8	8	8	8	9	9	11	12	12	11

Figure 22 Example for a working day of January



4 ILAP'S PORTFOLIO

4.1 Portfolio characteristics



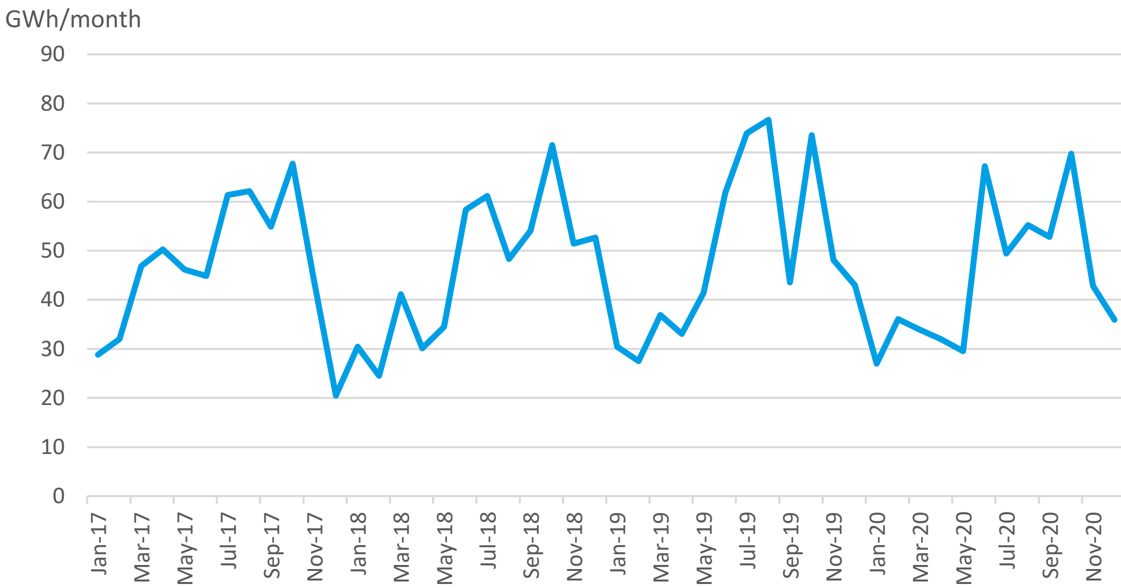
The portfolio consists of 2 wind farms. Totoral Wind Farm is located in Canela, Coquimbo Region. It has an installed capacity of 46 MW made up of 46 Vestas V90/2000 turbines, each with a nominal power of 2 MW. It has a connection point to SE Las Palmas 220 kV and it has been in operation since January 25 of 2010. In 2020, it generated 79.5 GWh, corresponding to a capacity factor of 19.7%.

The other project corresponds to the San Juan Wind Farm, located in Freirina, Atacama region. This wind farm has an installed capacity of 193.2 MW that can generate from 56 turbines, making it the second largest wind farm in Chile. It has been in operation since March 16, 2017 and has a connection point to the SEN in SE Eólica San Juan. In 2020, it generated 504.6 GWh, corresponding to a capacity factor of 29.7%.

4.2 Historical generation

San Juan wind farm has the characteristic of being located near the coast so it has a good capacity factor, as will be seen later. It can be noted that this wind farm has a fairly marked seasonality, reaching its maximum between the months of July and September and with a minimum between January and March. It is noted that the generation cycle is relatively predictable. Figure 23 shows the generation profile of the San Juan wind farm for the last 4 years.

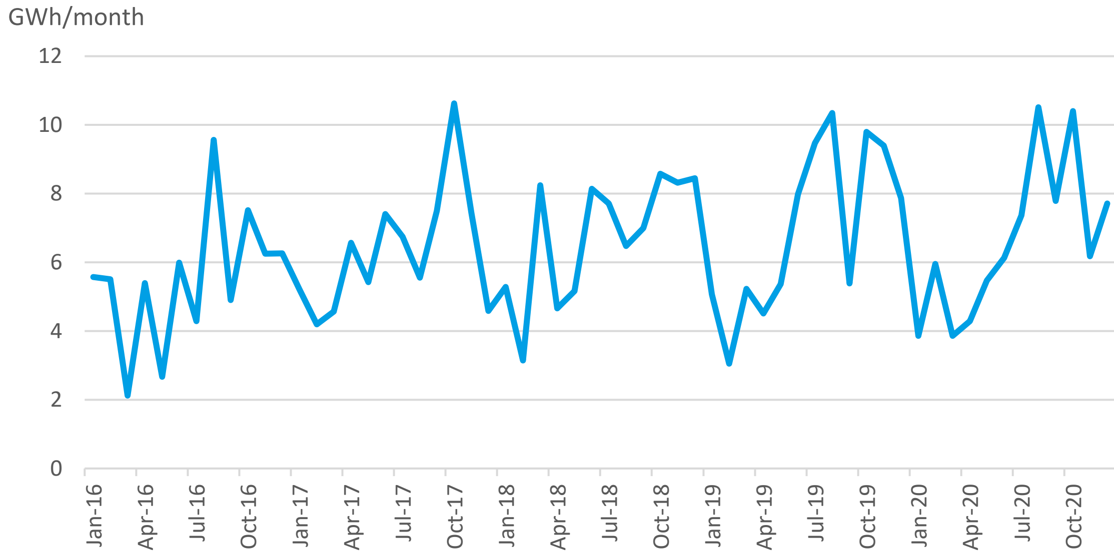
Figure 23 San Juan wind farm monthly generation from 2017 to 2020



Source: Own elaboration based on CEN.

The Totoral winid farm has a more unpredictable generation, where seasonality can be seen, but not in a very noticeable way. Figure 24 shows the generation of the last 5 years of the Totoral wind farm.

Figure 24 Totoral wind farm monthly generation from 2016 to 2020

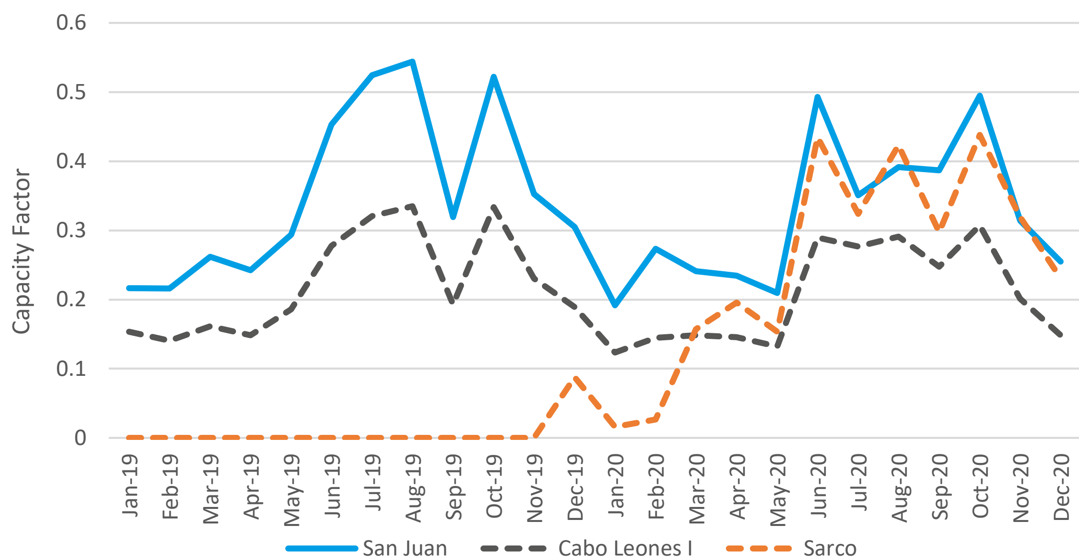


Source: Own elaboration based on CEN

4.3 Comparison regarding other wind projects

Below is a comparison of the San Juan wind farm with other farms in the area. It is compared to the wind farms with the best and worst capacity factor near San Juan. It can be seen that the San Juan wind farm is the one with the best performance in the area, with capacity factors similar to that of newer wind farms, such as Sarco, as can be seen in Figure 25. The difference between San Juan and other wind farms in the area with a worse plant factor is mainly due to the fact that it is located in an advantageous geographical area, closer to the coast and with stronger wind.

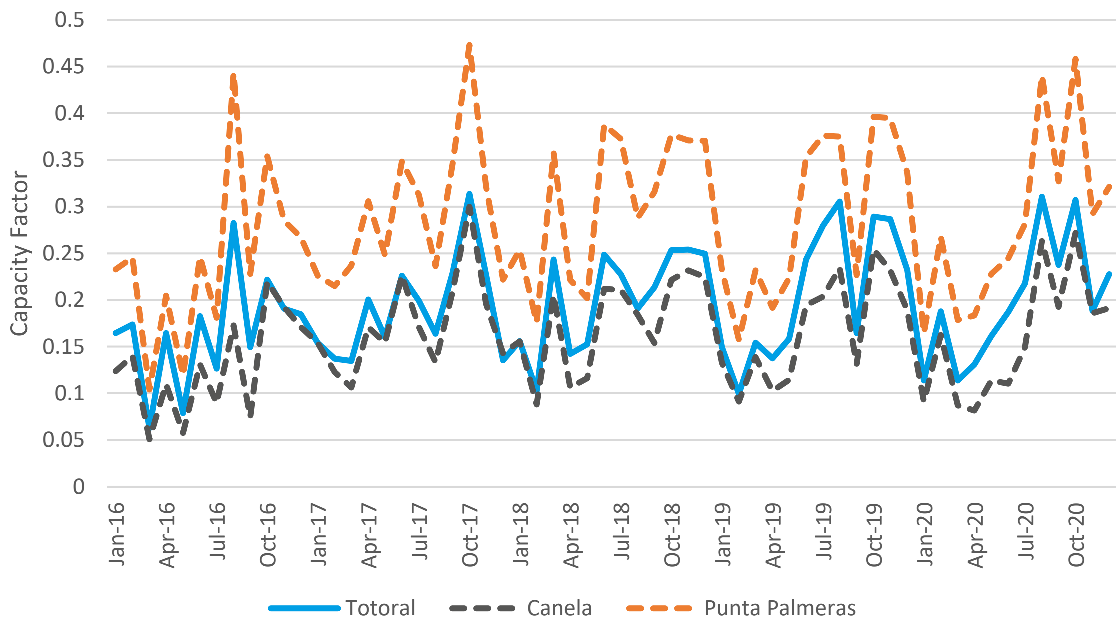
Figure 25 Capacity factor comparison between San Juan and other wind farms in the region



Source: Own elaboration based on CEN

In the case of the Totoral wind farm, it follows the same performance pattern as the other wind farms in the area. When comparing it with the wind farms with the best and worst capacity factors, it is seen that Totoral is close to the lowest capacity factor.

Figure 26 Capacity factor comparison between Totoral and the best and worst (in terms of capacity factor) wind farms in the region



Source: Own elaboration based on CEN

5 PPA Review

As mentioned in section **Error! Reference source not found.**, the generation segment is part of a m andatory pool type spot electricity market managed by the independent system coordinator (CEN). In this spot market, only generators are able to withdraw energy, and therefore are the ones that supply clients through bilateral contracts (PPA), which are of a financial nature. PPAs can be classified into three groups, according to the type of client being supplied.

- Contracts with distribution companies: these contracts are awarded through competitive auction processes and are intended to supply only regulated consumers.
- Contracts with non-regulated customers (also called free clients): these customers are entitled to sign contracts directly with generation companies and to freely negotiate prices. Free clients can also sign PPAs with distribution companies and in that case the distribution company buys the energy directly from a generator according to terms agreed bilaterally.
- Contracts with other generation companies.

The two wind farms, San Juan and Totoral, hold PPAs that fall into the first two categories. Both wind farms have contracts with regulated and non-regulated customers. In the following sections, the conceptual frame, and the main characteristic of these PPAs is described, according to the classification.

Before going into their description, it is important to highlight that each of the units has their own contracts, both of short and long term. On the one hand, Totoral has the following contracts:

- Regulated supply PPA with distribution companies.
- PPA with a mining company: “Minera Cerro Negro”.
- PPA to supply part of Walmart’s demand.
- PPA to supply Contitech’s demand.
- Several PPAs with some aggregated smaller clients.

On the other hand, San Juan has the following contracts:

- Regulated supply PPA with distribution companies.
- Supply contract with a distribution company for non-regulated clients.
- PPA with Metro, the company in charge of the subway system of Santiago.

5.1 PPAs for supplying regulated customers of distribution companies

The electricity supply for regulated customers of distribution companies is awarded through a competitive tender process, as it is regulated by law. As it was already described, the main laws governing the tender processes are Law N° 20.018 (Short Law II) and Law N° 20.805 (Distribution auction reform). According to this framework, the CNE is responsible of preparing the terms of the tender process while the distribution companies are only responsible for the administrative aspects.

A relevant objective is that distribution companies have enough energy contracted in order to be able to supply their regulated clients. This must be done five years in advance, in order to allow possible new generation capacity to be installed.

In order to implement this process, the CNE must every year develop a report that projects the demand of regulated customers. Considering this, and the contracts already signed, the needs for new energy contracts must be projected. With this under consideration, if the CNE determines that there is a need for new energy contracted a new tender process is started. The tender terms and methodology are defined by the CNE, which includes among other things the block size and division, and the supply period, which has a maximum of 20 years. Awarded PPAs are subsequently signed between each distribution company and each selected generator in the process. The long term nature of the tender contracts provides price and revenue stability.

One of the main risks to generators participating in the auction process is the regulatory provision that exposes generators to lower than contracted energy sales volumes to the extent that actual regulated demand is less than the demand projections used in the supply contracts (or awarded in the tender process). In the auction mechanism, the distribution companies, under the supervision of the CNE, make projections of regulated demand. Due to the uncertainty inherent in forecasts, it is possible that the actual energy demand from regulated customers of a distribution company differs from the projection, leading to a mismatch between demand and contracted energy supply. In the case that actual demand is less than the contracted energy at a particular time, the actual demand will be covered by all generators which have been awarded part of that supply in proportion to their energy contracts, which implies that the PPA revenues to generators could be less than the expected contracted amounts.

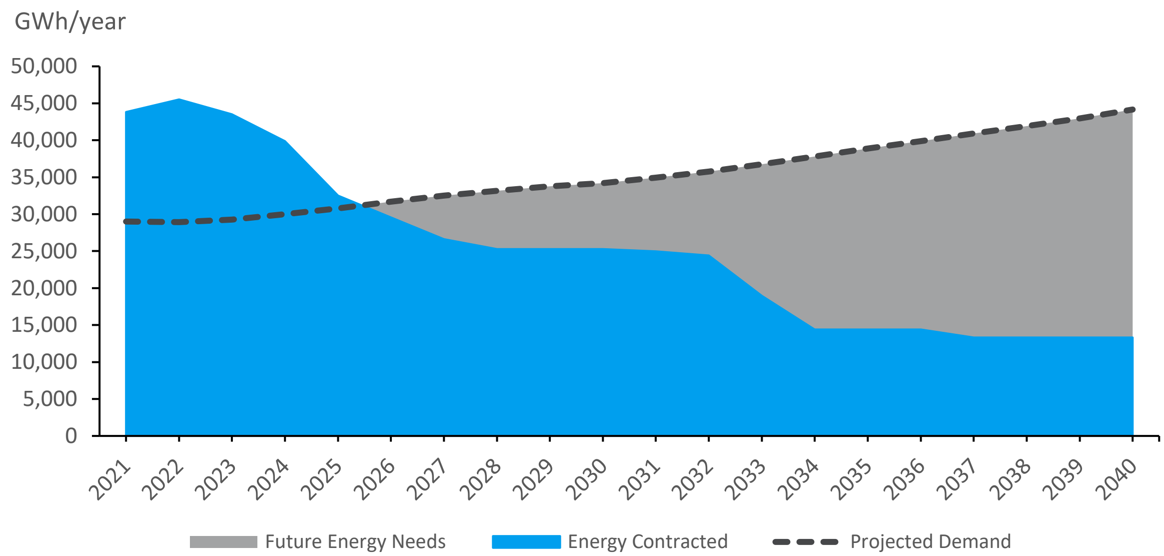
The CNE aims to reduce the potential error in these projections. The distribution companies can be penalized if they are found to have overstate their projected demand. In addition, the CNE has the ability to revise or completely reconstruct a forecast it believes to be flawed.

A noticeable degree of oversupply (overcontracting by distribution companies) has been observed in recent years and it is also expected until 2025. This has been largely driven by two factors. The first one is lower regulated demand compared to projections. The overestimation of demand in earlier projections resulted in the procurement of excess supply contracts to meet regulated demand.

A second factor has been the decision of some regulated customers to become free customers. Customers with a connected capacity between 5 MW and 0.5 MW are entitled to decide between being considered as regulated customers and non-regulated customers. This decision is binding for at least four years. Therefore, the migration of clients from regulated to non regulated causes the actual regulated energy demand to decrease comparatively to the projected values.

The following figure shows both the actual energy contracted and the energy needs projected by the CNE. It is possible to observe that after some years the effect of the oversupply decreases, and it is expected to be moderate as long as the projections are close to the actual future requirements.

Figure 27. Contracted energy and future needs projected for regulated customers.



As it was mentioned, the projections used by the CNE are updated every year taking into account new information, and a new tender process is carried out when there is a projected need for energy supply for regulated customers after a period of five years.

Table 22 and Figure 28 shows the oversupply of energy until the year 2025. It is seen that this occurs with a maximum in the years 2021 and 2022 to decrease in subsequent years, from 2026 onwards the projected demand exceeds the contracted energy, therefore the CNE must request new tenders in order to supply the projected demand.

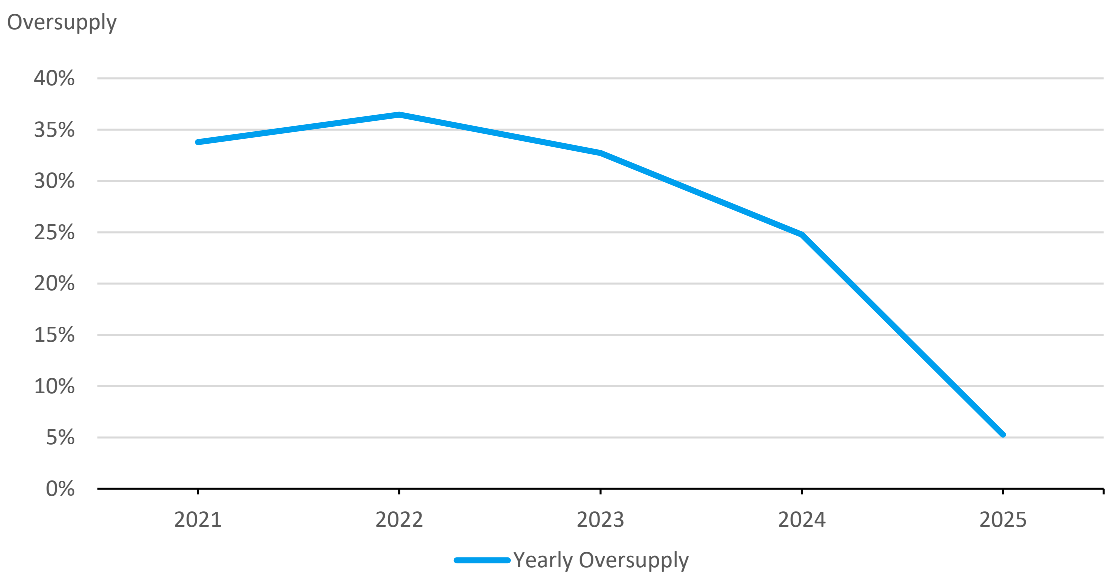
Oversupply is calculated as it follows:

$$\text{Oversupply} = \frac{\text{Energy Contracted} - \text{Projected Demand}}{\text{Energy Contracted}}$$

Table 22 Oversupply for regulated customers

Year	Demand [GWh]	Energy Contracted [GWh]	Yearly Oversupply
2021	29,019	43,831	33.8%
2022	28,929	45,532	36.5%
2023	29,271	43,507	32.7%
2024	30,016	39,897	24.8%
2025	30,786	32,498	5.3%

Figure 28 Oversupply for regulated customers



The two wind farms in this portfolio, San Juan and Totoral, hold contracts with distribution companies for the Tendering Process 2013/03 Second Call, which took place in 2014. In the process four blocks were defined, in which the first two were divided according to their hours of the day. The blocks defined were the following:

- Block 1: from January 1st **2016** to December 31th **2030.** This is divided into three sub-blocks:
    - N° 1-A: 250 GWh in the following hours 23:00-07:59
    - N° 1-B: 500 GWh in the following hours 08:00-17:59
    - N° 1-C: 250 GWh in the following hours 18:00-22:59

- Block 2: from January 1st **2017** to December 31th **2031.** This is divided into three sub-blocks:
    - N° 2-A: 250 GWh de 23:00-07:59
    - N° 2-B: 500 GWh de 08:00-17:59
    - N° 2-C: 250 GWh de 18:00-22:59

- Block 3: from January 1st **2018** to December 31th **2032.**, without hourly division. It considers 2,400 GWh in 2018. From 2019 onwards it considers a 6,000 GWh block per year.

- Block 4: from January 1st **2019** to December 31th **2033.**, without hourly division. It considers 2,500 GWh in 2019. From 2020 onwards it considers a 5,000 GWh block per year.

San Juan was awarded 68.2 GWh per year in block 2-A, 40.9 GWh per year in block 2-C and 218 GWh per year in block 3. Meanwhile, Totoral was awarded 45.4 GWh per year in block 4.

Since both plants are expected to have an energy surplus, considering their energy generation and the expected amounts demanded by regulated consumers of distribution companies, it becomes attractive to enter into shorter term PPAs with non regulated consumers, until the effects of the oversupply described are moderate.

5.2 PPA with Metro

In addition to the distribution company PPAs, the San Juan wind farm also holds a PPA with Metro de Santiago, the subway system of the city of Santiago. The terms of this 15-year PPA state that Metro will purchase energy from San Juan from April 2017 up to March 2032. The Metro PPA provides San Juan wind farm a significant revenue stream. It is the only PPA with non-regulated customers in the portfolio that extends beyond 2026.

Metro relies on PPAs with distribution companies and generators in order to meet its energy demand requirements. The energy supplied by San Juan in recent years has been close to 70 GWh/year. Since the 2020 and 2021 demand has been affected by the sanitary situation, it cannot be taken as representative of future consumption levels. For the period 2022-2023 a supply of 75 GWh/year is projected. In addition, Metro has new networks extensions planned for the coming years. Therefore, a future supply by San Juan of 79 GWh/year is expected.

Currently, Metro has a PPA with Enel Distribución, one of the largest distribution companies in the country, and a separate PPA with a solar generation company to be supplied by El Pelícano solar PV plant. The Enel and Pelícano PPAs take priority over the San Juan PPA, which means that San Juan is contracted to supply Metro's residual energy demand. Specifically, 40% of Metro demand is to be supplied by Enel Distribución and the remaining 60% is to be supplied by El Pelícano and San Juan wind farm, in that order. Despite being the third priority supply for Metro energy demand, San Juan dispatch profile complements the typical solar dispatch profile as the majority of the output from wind plants like San Juan occurs at dawn and dusk when solar generation is limited.

The maximum energy that San Juan can supply in each hour is the available energy generation that is not being used to supply the PPA with distribution companies, with a maximum annual block of 355 GWh. Additional energy demanded by Metro may be supplied by San Juan, buying it in the spot market and charging the marginal cost plus a fee.

The energy that San Juan supplies to Metro corresponds to surplus energy after supplying its obligations to the distribution companies. Hence, the Metro PPA allows San Juan to hedge against the risk of demand and supply mismatches in the tender process contract.

It is also important to mention that the PPA protects San Juan against the possibility of a difference in marginal costs between the withdrawal node and the injection node through an internodal charge that will be assumed by Metro. This may be an important aspect that allows protecting San Juan against the risk mentioned, and can be particularly relevant at least until the commissioning of the Kimal-Lo Aguirre HVDC line.

5.3 Non regulated Customer Contracts

As mentioned before, the contracts with non regulated customers are negotiated bilaterally, being free to negotiate prices and energy amounts. Each of these wind farms has signed this type of PPA in an independent way. Both plants have some long duration contracts and others with a shorter period of supply. A general overview of existing contracts is provided.

Before entering the description for each of the generation plants, it is important to mention that normally a PPA includes energy supply but also capacity must be paid. Almost all the PPAs in the portfolio, consider a pass-through scheme regarding the cost associated with the power demand of the clients (and all the other cost associated to the withdrawal of energy in the spot market) fully to the clients.

In the case of Totoral wind farm, the number of contracts involved is comparatively high. This plant has signed fifteen contracts with different non-regulated clients. Despite this, two of them may be categorized of greater relevance in terms of the energy involved: the contract with Walmart and the one with the mining company “Minera Cerro Negro”. The first one has a shorter period of supply, ending in March 2022 (inclusive). On the other hand, the PPA with Minera Cerro Negro will continue until December 2025 (inclusive). These PPAs consider energy blocks of 27.7 GWh and 40 GWh per year, respectively.

Almost all the other PPAs that Totoral has were signed through a trader. A trader pools the demand of several smaller non regulated clients in order to obtain a more stable and larger demand, and in this way be able to get more attractive wholesale market prices for their customers. Despite the relationship actually being through the trader, in this case ECOM, the contracts are signed with each of the final clients. These are:

- Agricovial
- Ceresita
- Inmobiliara Encomenderos
- PSA
- Punta Blanca
- MN Agrícola Ltd
- Viña Caliterra
- JEPSEN
- Universidad de los Andes
- ICB
- VFCH

Together these PPAs represent almost 40 GWh per year of energy demand, a value that will gradually decrease because each of the PPAs has different extensions. The earlier expiration date is December 2022, while the last one to end will be in place until March 2026. The average energy supplied from July 2021 until March 2026 through these contracts is 27.1 GWh per year.

It is important to note that the supply period of the non regulated contracts described does not exceed the year 2026. This is reasonable considering the oversupply phenomenon described with respect to the PPAs for regulated customers of distribution companies. As a consequence of the oversupply, a lower quantity of energy is expected to be demanded by regulated customers compared to the contracted energy. This effect is expected to drastically decrease after 2025, as it was previously explained.

In the case of San Juan, the number of PPAs with non regulated customers is comparatively lower, being two PPAs. As it was mentioned before, one of them is with Metro. The other PPA is an agreement to sell energy to Enel Distribución, in order to supply non regulated customers. This contract considers a 180 GWh per year until December 2023 (inclusive).

6 Results: Marginal Cost and Capacity Projections

This chapter provides monthly marginal cost projection results for several nodes of interest. The tables below show annual average marginal cost projections for several nodes located primarily in the north and central zone of the country. Projections for representative nodes in north, central and south regions are shown in the figures below. The nodes selected are Crucero 220 kV, Maitencillo 220 kV, Las Palmas 220 kV, Quillota 220 kV, and Charrúa 220 kV. Projections corresponding to capacity credit and payments are also shown, specifically the Definitive Adequacy Capacity and the revenues corresponding to the capacity market.

6.1 Energy marginal cost projection

This section shows the marginal cost projection results for selected nodes of interest, according to the assumptions described in chapter 3. The following table contains annual average marginal cost projections. Then projections monthly average projections for nodes Crucero 220 kV, Maitencillo 220 kV, Las Palmas 220 kV, Quillota 220 kV and Charrúa 220 kV are show. Results for both the Base Scenario and the downside scenario are presented.

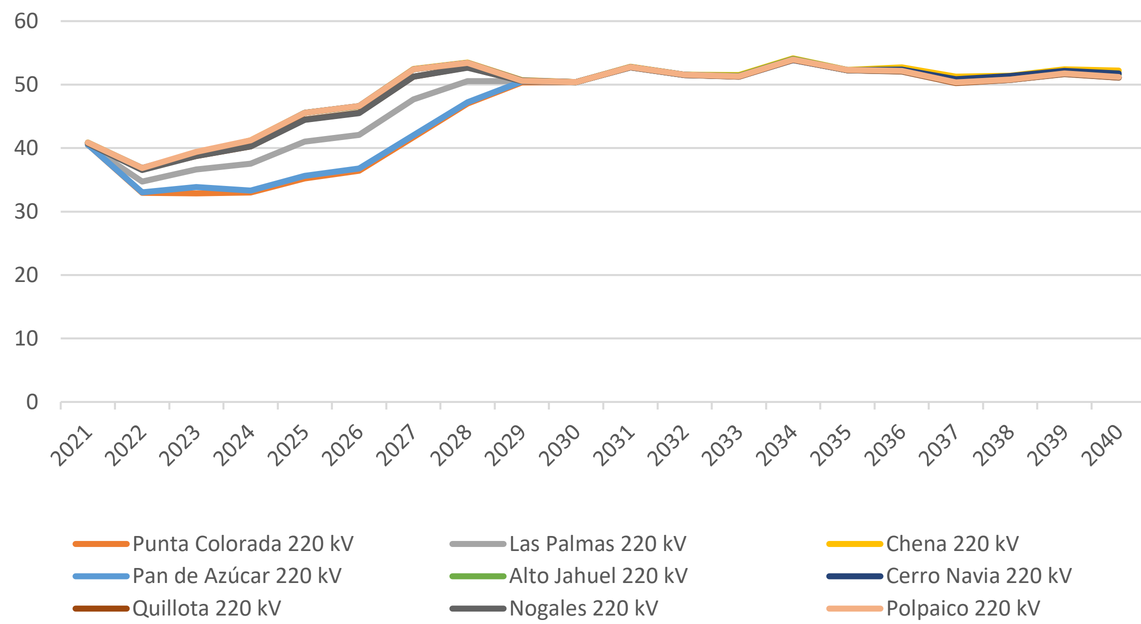
6.1.1 Base Scenario

This section shows the results of the marginal cost projections for the Base Scenario.

Table 23 Yearly average marginal cost projection for base scenario

Year	Punta Colorada 220 kV	Las Palmas 220 kV	Chena 220 kV	Pan de Azúcar 220 kV	Alto Jahuel 220 kV	Cerro Navia 220 kV	Quillota 220 kV	Nogales 220 kV	Polpaico 220 kV
2021	40.58	40.47	40.88	40.58	40.86	40.84	40.84	40.69	40.84
2022	32.93	34.72	36.85	33.02	36.82	36.85	36.70	36.54	36.85
2023	32.86	36.65	39.06	33.84	38.79	39.24	38.73	38.74	39.41
2024	32.98	37.54	41.21	33.30	41.09	41.16	40.27	40.26	41.20
2025	35.23	41.00	45.56	35.63	45.53	45.56	44.49	44.45	45.57
2026	36.44	42.09	46.61	36.77	46.58	46.60	45.55	45.50	46.61
2027	41.72	47.65	52.44	42.03	52.40	52.43	51.27	51.25	52.44
2028	47.00	50.56	53.46	47.22	53.41	53.44	52.70	52.69	53.43
2029	50.34	50.55	50.67	50.50	50.62	50.67	50.57	50.56	50.59
2030	50.40	50.39	50.41	50.40	50.40	50.41	50.38	50.38	50.41
2031	52.74	52.74	52.80	52.75	52.78	52.76	52.71	52.73	52.77
2032	51.52	51.51	51.56	51.53	51.55	51.53	51.48	51.50	51.54
2033	51.29	51.29	51.48	51.30	51.41	51.26	51.26	51.28	51.32
2034	53.89	53.92	54.13	53.91	54.05	53.86	53.90	53.94	53.94
2035	52.28	52.28	52.33	52.29	52.29	52.28	52.24	52.29	52.30
2036	52.13	52.12	52.70	52.14	52.38	52.37	52.05	52.13	52.17
2037	50.30	50.31	51.23	50.31	50.77	50.84	50.25	50.32	50.36
2038	50.75	50.76	51.40	50.76	50.95	51.37	50.73	50.78	50.81
2039	51.71	51.72	52.43	51.72	52.03	52.15	51.67	51.73	51.76
2040	51.12	51.15	52.19	51.13	51.56	51.78	51.10	51.16	51.19

Figure 29 Yearly average marginal cost projection for the Base Scenario



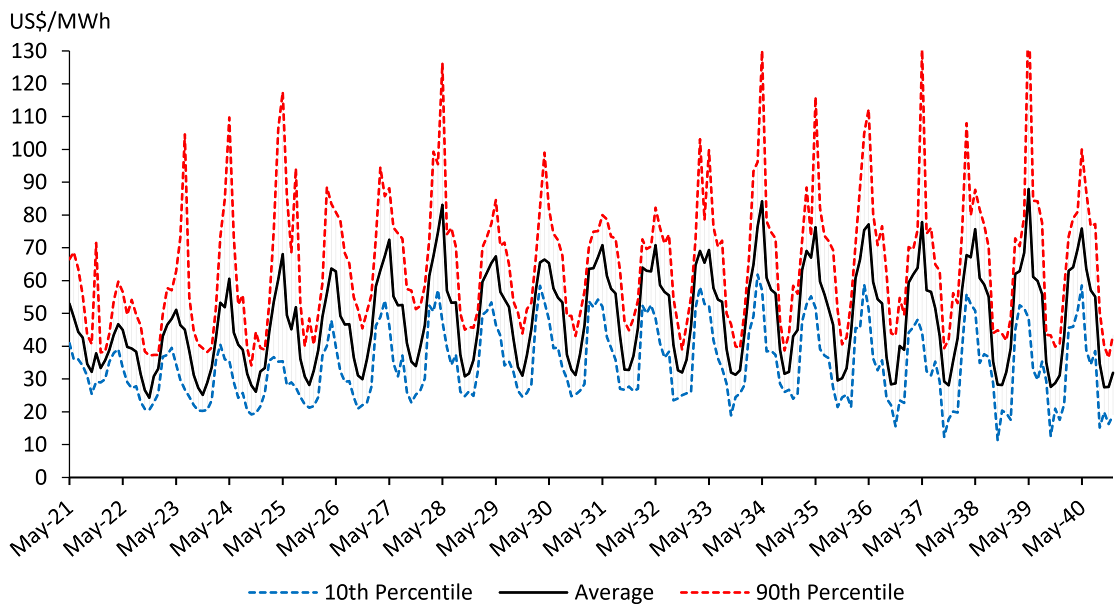
The following graphs show the monthly average marginal cost projections. The expected monthly average marginal costs are represented by a black solid line. Additionally, in order to present the marginal cost variability, the 10th and 90th percentiles have been included. The 10th percentile represents the monthly average marginal cost under which 10% of observations fall, and the 90th percentile is interpreted similarly, but for 90% of observations.

The marginal cost projection results for the node Quillota 220 kV are presented first. This node generally serves as a reference node for the SEN, given that it is located in a high demand zone in the central area of the system.

6.1.1.1 Marginal cost projection results for node Quillota 220 kV

Figure 30 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Quillota 220 kV.

Figure 30 Monthly average marginal cost projection for node Quillota 220kV – Base Scenario



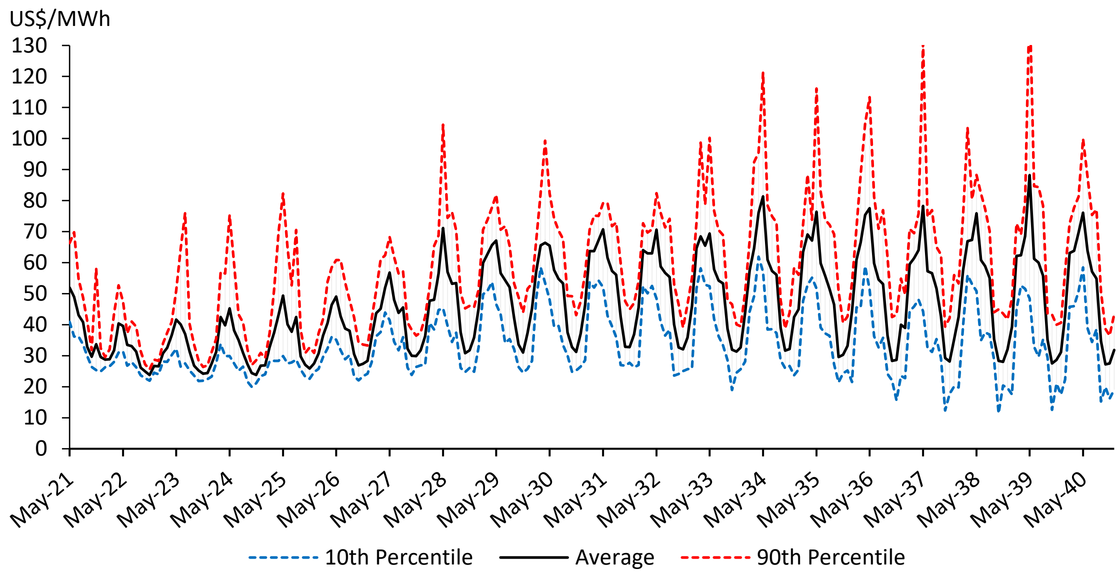
In Figure 30 above, it can be seen the SEN's annual hydrological cycles, alternating months with moderate or relatively low projected energy marginal costs and months with higher costs. Months showing average low energy marginal costs are related to the rainy season, expecting on average an increase in hydro inflows, substituting thermal generation and, therefore, leading on average to moderate energy marginal costs. This situation is normally observed until the ice melting season (October-March). When the latter is ending, it is necessary to increase the thermal generation participation due to a decrease in hydro resources availability, which leads to rising expected marginal costs in the months of March and April.

The expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 48.6 US$/MWh.

6.1.1.2 Marginal cost projection results for node Crucero 220 kV

Figure 31 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Crucero 220 kV. The expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 45.7 US$/MWh.

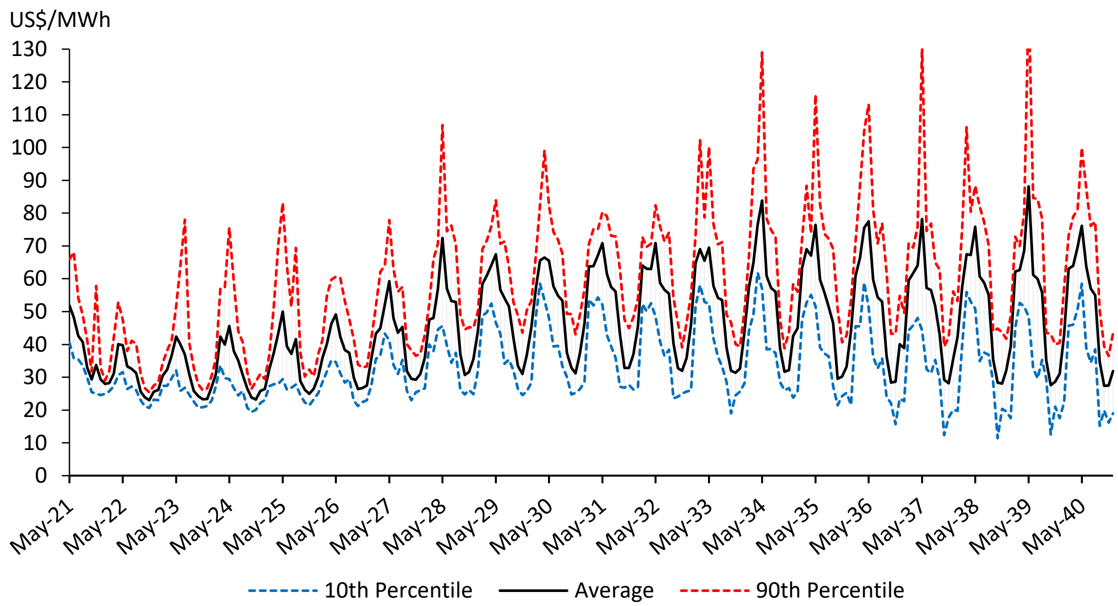
Figure 31 Monthly average marginal cost projection for node Crucero 220kV – Base Scenario



6.1.1.3 Marginal cost projection results for node Maitencillo 220 kV

Figure 32 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Maitencillo 220 kV. The expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 45.5 US$/MWh.

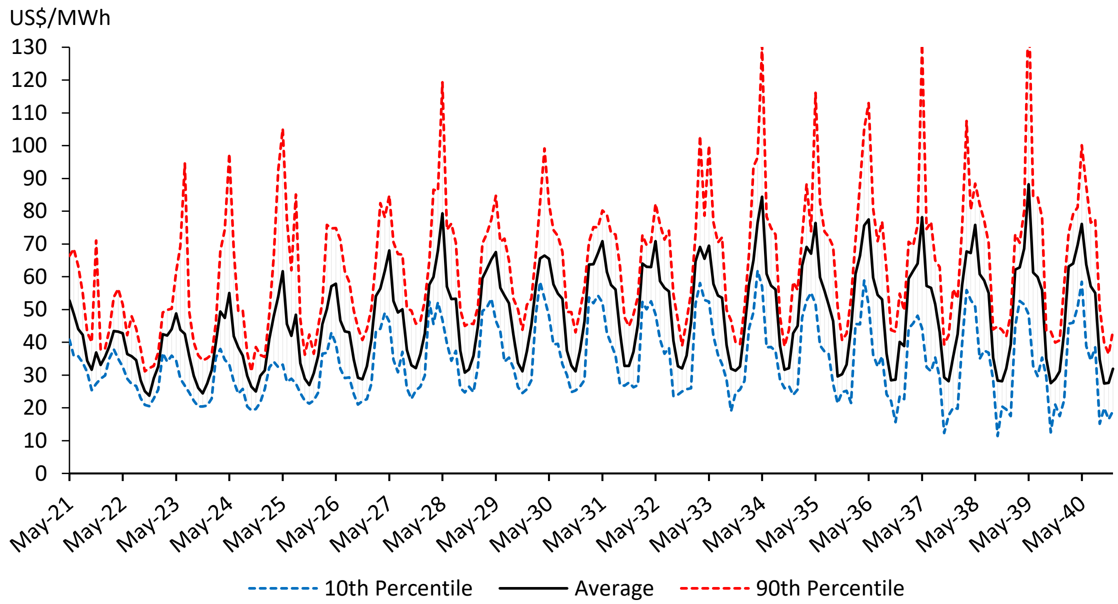
Figure 32 Monthly average marginal cost projection for node Maitencillo 220kV – Base Scenario



6.1.1.4 Marginal cost projection results for node La Palmas 220 kV

Figure 33Figure 33Figure 33Figure 32 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Las Palmas 220 kV. The expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 47.6 US$/MWh.

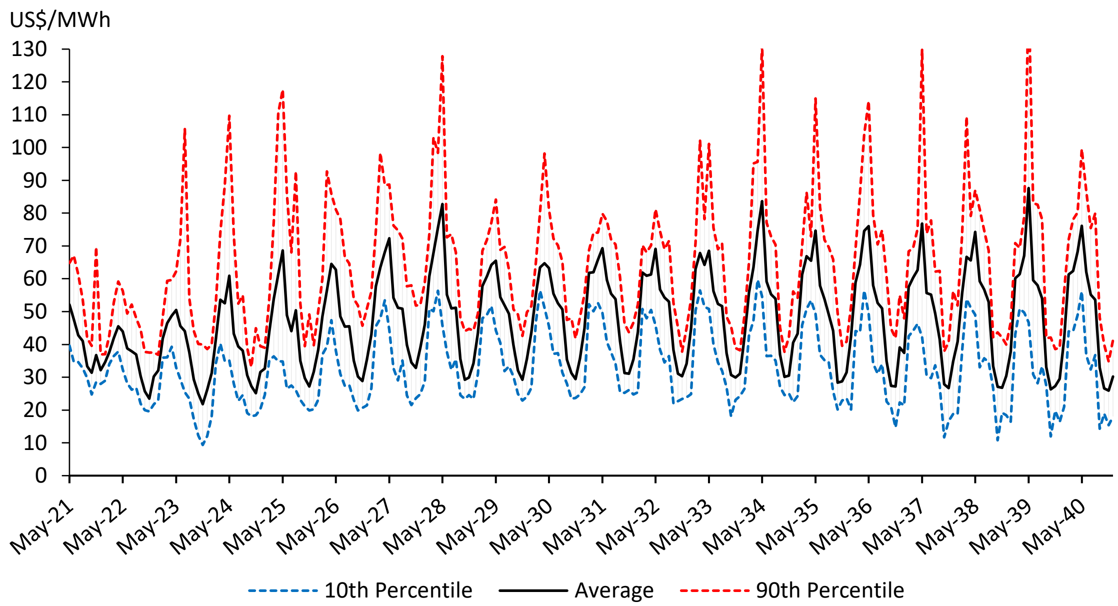
Figure 33 Monthly average marginal cost projection for node Las Palmas 220kV – Base Scenario



6.1.1.5 Marginal cost projection results for node Charrúa 220 kV

Figure 34Figure 32 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Charrúa 220 kV. The expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh.

Figure 34 Monthly average marginal cost projection for node Charrúa 220kV – Base Scenario



It can be seen in the figure above that the monthly average marginal cost projected for the node Charrúa 220 kV has a similar behavior to the marginal cost projected for the node Quillota 220 kV, but generally it has lower marginal cost projected. This is mainly because Charrúa 220 kV is located in an area with relevant hydroelectric generation resources in the south of the SEN.

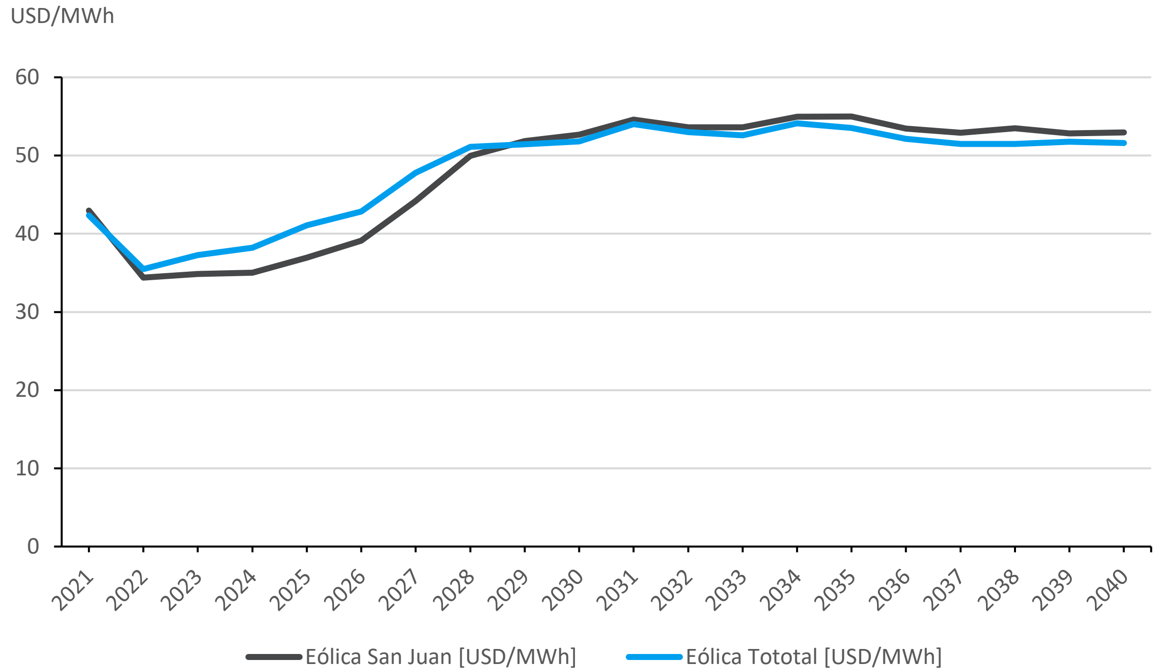
6.1.1.6 Weighted injection price

Table 24Table 24 shows the annual average of the weighted injection price. This price reflects the price captured at the times when the project generated energy. In the same way as the aforementioned table, Figure 35 shows the annual average of prices.

Table 24 Annual average of weighted injection price

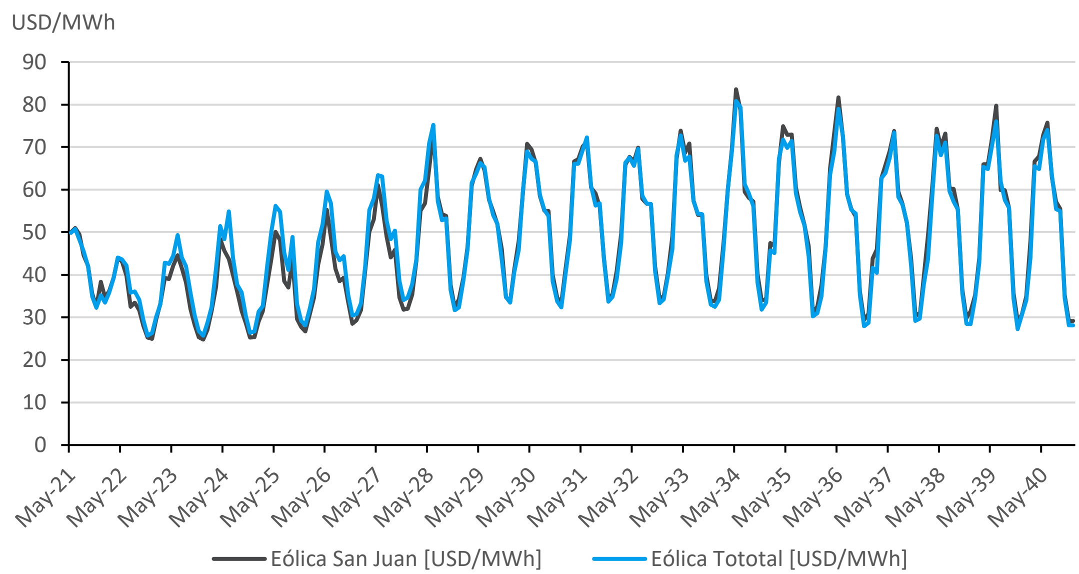
Year	Eólica San Juan [USD/MWh]	Eólica Tototal [USD/MWh]
2021	42.95	42.34
2022	34.39	35.48
2023	34.84	37.28
2024	35.02	38.20
2025	36.96	41.09
2026	39.12	42.85
2027	44.20	47.80
2028	49.95	51.13
2029	51.86	51.44
2030	52.65	51.79
2031	54.61	54.00
2032	53.59	53.00
2033	53.62	52.58
2034	54.95	54.11
2035	54.99	53.51
2036	53.44	52.14
2037	52.90	51.46
2038	53.49	51.48
2039	52.82	51.78
2040	52.94	51.58

Figure 35 Annual average of weighted injection price for San Juan and Totoral wind farms



Finally, Figure 36 shows the monthly average of the weighted injection price within the range of projections.

Figure 36 Monthly average of weighted injection price



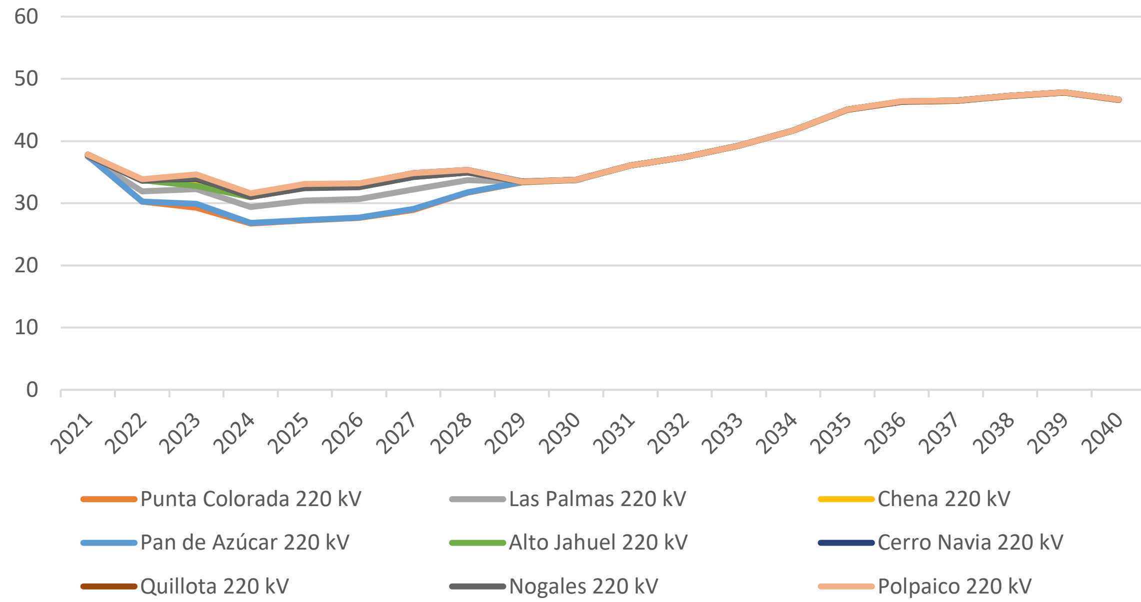
6.1.2 Downside sensitivity case

This section shows the results of the marginal cost projections for the downside sensitivity case.

Table 25 Yearly average marginal cost projection for sensitivity case

Year	Punta Colorada 220 kV	Las Palmas 220 kV	Chena 220 kV	Pan de Azúcar 220 kV	Alto Jahuel 220 kV	Cerro Navia 220 kV	Quillota 220 kV	Nogales 220 kV	Polpaico 220 kV
2021	37.60	37.48	37.84	37.60	37.81	37.79	37.80	37.68	37.80
2022	30.24	31.88	33.73	30.28	33.68	33.76	33.74	33.60	33.87
2023	29.27	32.28	33.41	29.91	32.77	33.89	34.05	34.08	34.63
2024	26.73	29.38	31.17	26.83	30.97	31.31	31.01	31.03	31.59
2025	27.22	30.42	33.01	27.28	32.97	33.03	32.46	32.43	33.07
2026	27.63	30.67	33.13	27.69	33.09	33.15	32.60	32.57	33.18
2027	28.94	32.20	34.81	29.05	34.77	34.83	34.23	34.22	34.86
2028	31.71	33.69	35.31	31.76	35.27	35.33	34.95	34.92	35.34
2029	33.36	33.44	33.45	33.42	33.40	33.48	33.45	33.44	33.45
2030	33.75	33.75	33.74	33.75	33.72	33.75	33.75	33.74	33.76
2031	36.08	36.08	36.08	36.08	36.05	36.08	36.07	36.07	36.09
2032	37.41	37.41	37.40	37.41	37.38	37.41	37.39	37.39	37.41
2033	39.26	39.26	39.26	39.27	39.24	39.27	39.25	39.25	39.27
2034	41.68	41.69	41.68	41.69	41.65	41.68	41.66	41.69	41.69
2035	45.07	45.08	45.06	45.07	45.03	45.07	45.04	45.08	45.08
2036	46.36	46.37	46.37	46.37	46.34	46.37	46.32	46.37	46.38
2037	46.48	46.50	46.49	46.49	46.46	46.48	46.47	46.50	46.50
2038	47.26	47.26	47.27	47.26	47.24	47.26	47.23	47.27	47.27
2039	47.81	47.82	47.84	47.82	47.80	47.81	47.79	47.82	47.83
2040	46.63	46.65	46.67	46.64	46.63	46.64	46.61	46.64	46.65

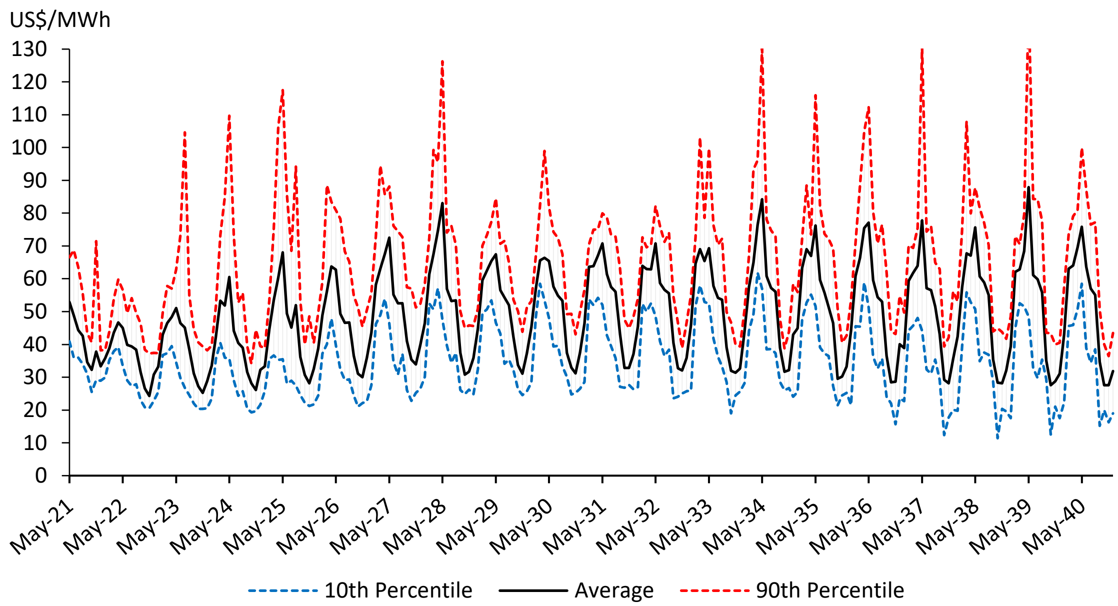
Figure 37 Yearly average marginal cost projection for sensitivity case



6.1.2.1 Marginal cost projection results for node Quillota 220 kV

Figure 38Figure 38 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Quillota 220 kV. The expected average marginal cost projected for the node Quillota 220 kV between 2021 and 2040 (next 20 years) is 38.6 US$/MWh.

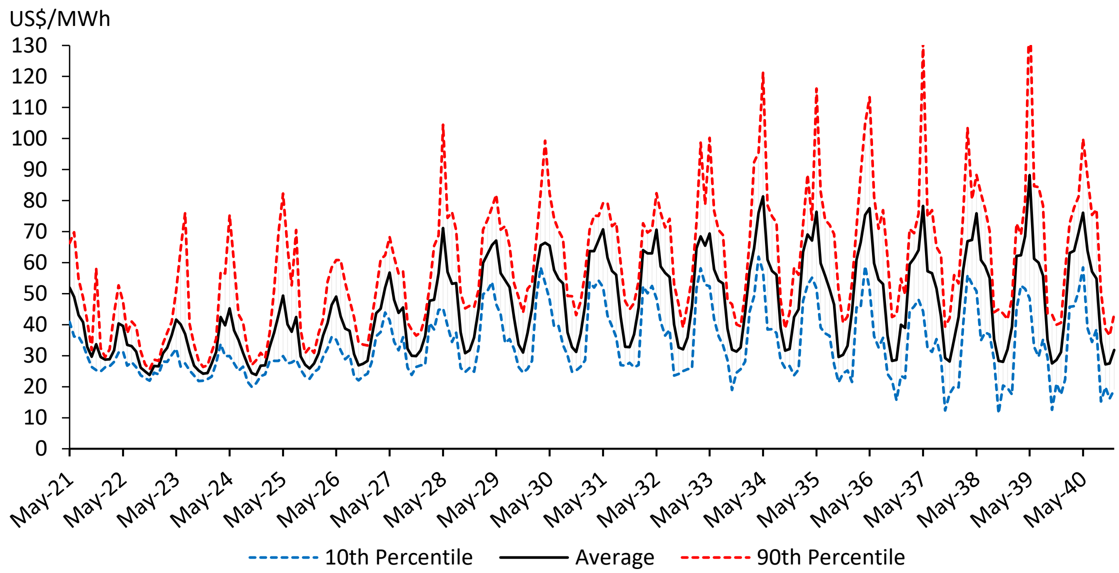
Figure 38 Monthly average marginal cost projection for node Quillota 220kV – Sensitivity Case



6.1.2.2 Marginal cost projection results for node Crucero 220 kV

Figure 39 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Crucero 220 kV. The expected average marginal cost projected for the node Crucero 220 kV between 2021 and 2040 (next 20 years) is 37 US$/MWh.

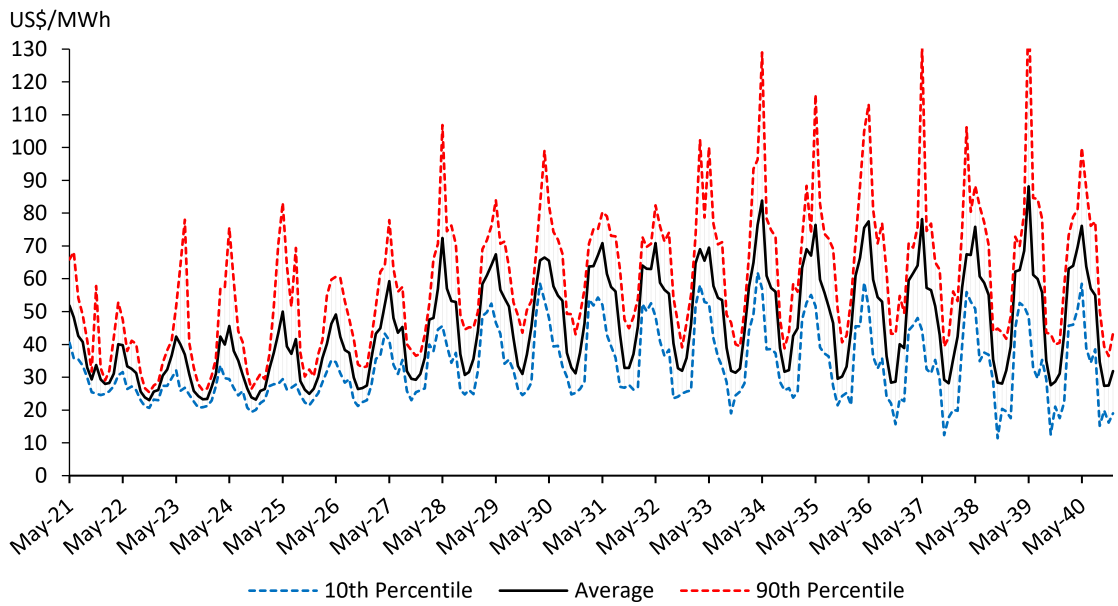
Figure 39 Monthly average marginal cost projection for node Crucero 220kV – Sensitivity Case



6.1.2.3 Marginal cost projection results for node Maitencillo 220 kV

Figure 40 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Maitencillo 220 kV. The expected average marginal cost projected for the node Maitencillo 220 kV between 2021 and 2040 (next 20 years) is 36.8 US$/MWh.

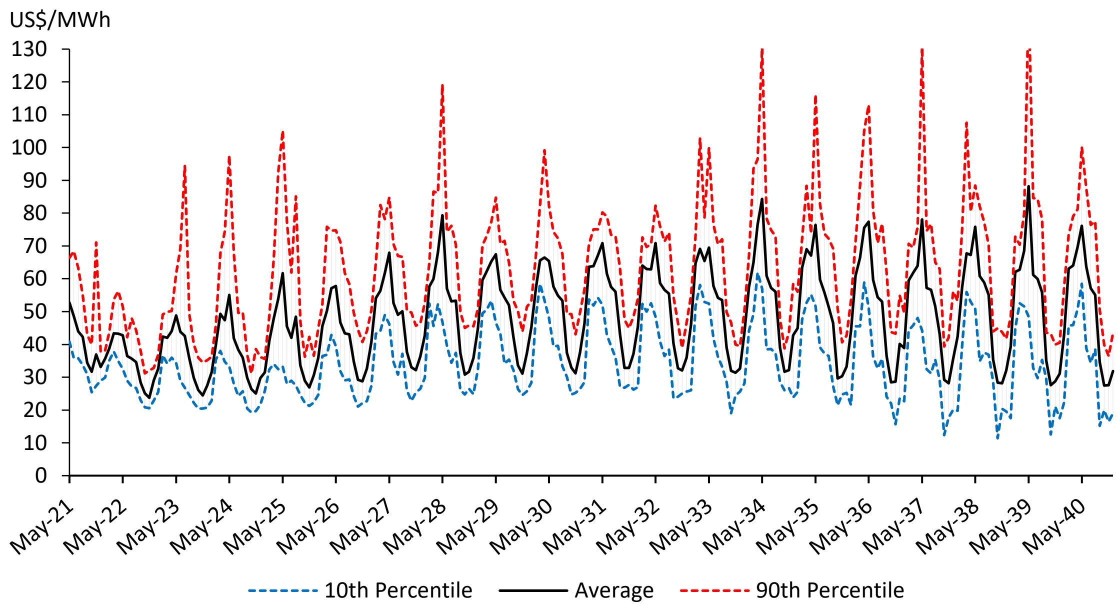
Figure 40 Monthly average marginal cost projection for node Maitencillo 220kV – Sensitivity Case



6.1.2.4 Marginal cost projection results for node La Palmas 220 kV

Figure 41Figure 32 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Las Palmas 220 kV. The expected average marginal cost projected for the node Las Palmas 220 kV between 2021 and 2040 (next 20 years) is 38 US$/MWh.

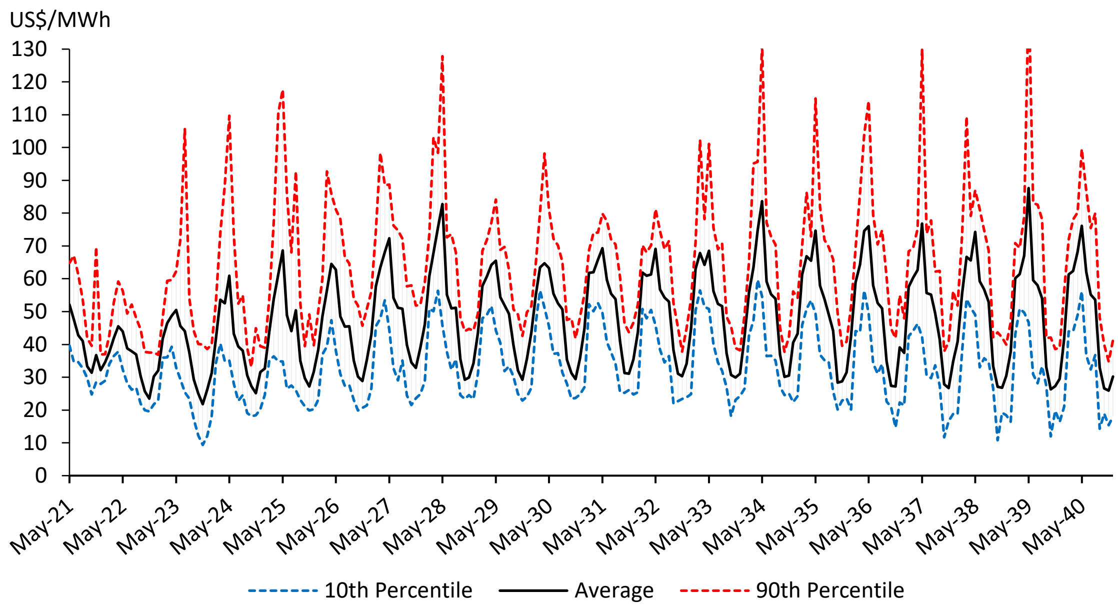
Figure 41 Monthly average marginal cost projection for node Las Palmas 220kV – Sensitivity Case



6.1.2.5 Marginal cost projection results for node Charrúa 220 kV

Figure 42Figure 32 shows the expected monthly average marginal cost projection and 10th and 90th percentiles for the node Charrúa 220 kV. The expected average marginal cost projected for the node Charrúa 220 kV between 2021 and 2040 (next 20 years) is 37.3 US$/MWh.

Figure 42 Monthly average marginal cost projection for node Charrúa 220kV – Sensitivity Case



6.2 Capacity payment projections

This section shows the projections corresponding to the Definitive Adequacy Capacity and the projected income from the capacity market. The following table shows the Definitive Adequacy Capacity projections and annual income projections for each year in the range 2021-2040.

Table 26 Definitive Adequacy Capacity projection and annual income projection

	San Juan		Totoral	
Year	Definitive Adequacy Capacity [MW]	Annual Income [MM USD]	Definitive Adequacy Capacity [MW]	Annual Income [MM USD]
2021	27.22	2.55	4.71	0.45
2022	27.20	2.55	4.71	0.45
2023	27.67	2.59	4.79	0.45
2024	28.99	2.72	5.02	0.48
2025	29.85	2.80	5.16	0.49
2026	30.43	2.85	5.27	0.50
2027	31.93	2.99	5.53	0.52
2028	32.39	3.04	5.60	0.53
2029	32.72	3.07	5.66	0.54
2030	32.78	3.07	5.67	0.54
2031	33.08	3.10	5.72	0.54
2032	33.24	3.12	5.75	0.55
2033	33.09	3.10	5.72	0.54
2034	33.48	3.14	5.79	0.55
2035	33.46	3.14	5.79	0.55
2036	33.21	3.11	5.74	0.54
2037	33.02	3.09	5.71	0.54
2038	33.35	3.13	5.77	0.55
2039	33.47	3.14	5.79	0.55
2040	33.75	3.16	5.84	0.55

6.2.1 Income projection from the capacity market

The plots below (Figure 43 and Figure 44) show the income from capacity payments for the San Juan and Totoral projects. In both cases, it can be noted that revenues increase during the first years, especially between 2021 and 2030. This is the result of the change in the mix of generation technologies, especially due to decarbonization, which makes the recognized sufficiency power of the system is lower, which increases payments.

Figure 43. Annual income projection for San Juan wind farm

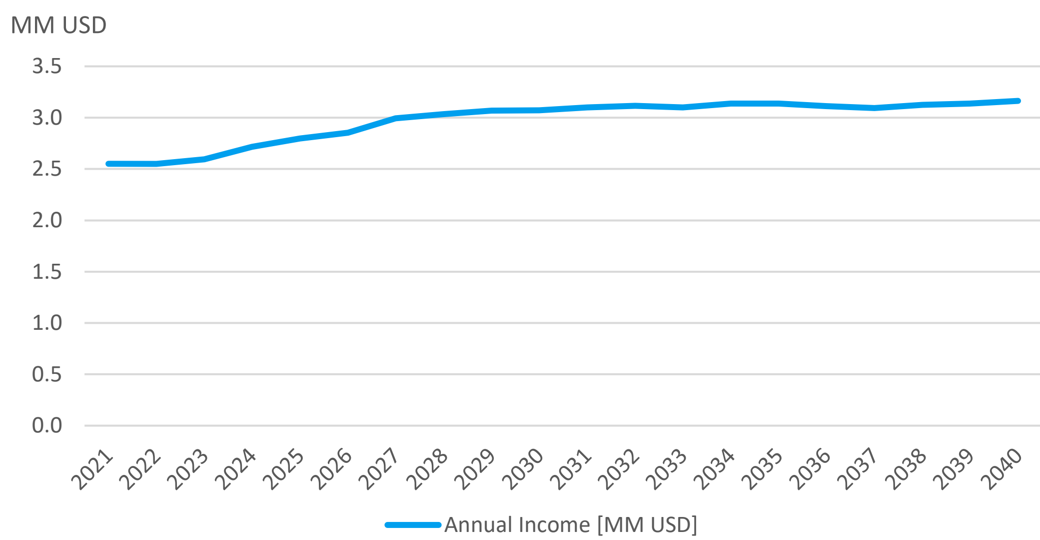
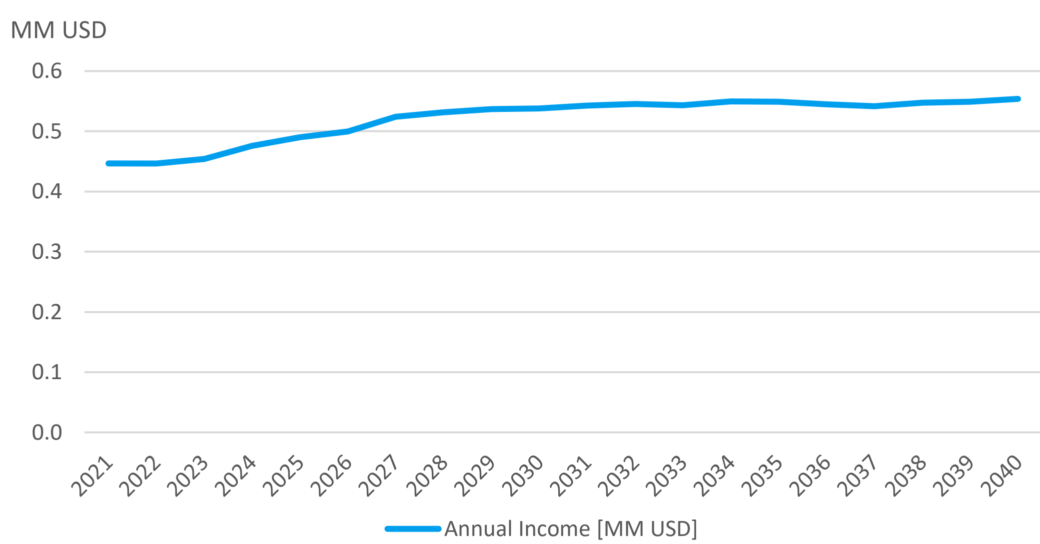


Figure 44. Annual income projection for San Juan wind farm



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To the Issuer and the Guarantors as to Chilean law

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June 9, 2021