Management's Discussion and Analysis

As at and for the year ended December 31, 2022

MANAGEMENT'S DISCUSSION AND ANALYSIS

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars unless otherwise indicated.)

This Management's Discussion and Analysis ("MD&A") dated March 8, 2023, is provided to enable readers to assess the results of operations, liquidity and capital resources of TriSummit Utilities Inc. ("TSU" or the "Company") as at and for the year ended December 31, 2022. This MD&A should be read in conjunction with the accompanying audited consolidated financial statements as at and for the year ended December 31, 2022 (the "Consolidated Financial Statements").

The Company's presentation currency is in Canadian dollars. In this MD&A, references to "$" are to Canadian dollars unless otherwise indicated. The Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") as codified by the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"). Throughout this MD&A, reference to GAAP refers to U.S. GAAP. Any reference to per Common Share measures are presented on a basic basis, unless otherwise indicated.

This MD&A refers to certain terms commonly used in the rate-regulated utility industry, such as "rate-regulated", "rate base" and "return on equity". The terms "rate base" and "return on equity" are key performance indicators but are not considered to be non-GAAP measures. Rate base is an amount that a utility is required to calculate for regulatory purposes, and generally refers to net book value of the utility's assets for regulatory purposes. Return on equity or "ROE" is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base. The Company refers to the rate base of its utility businesses because it believes that such term assists in understanding the Company's business and is commonly used by investors to help evaluate the performance of rate-regulated utilities. For a discussion of these terms and other terms commonly used in the rate-regulated utility industry, please see the "*Business of the Company - Utilities Business*" section in the annual information form of TSU dated March 8, 2023 (the "Annual Information Form").

Abbreviations, acronyms, and capitalized terms used in this MD&A that are not otherwise defined herein are used consistently with the definitions in the Annual Information Form.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "should", "believe", "plan", "would", "could", "focus", "forecast", "opportunity" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: expected success of financing plans and strategies, including maintenance of TSU's credit rating; the expected safety and reliability of TSU's operations; expectations regarding the PNG Reactivation Project (as defined herein) and the Salvus to Galloway Project (as defined herein); the GCOC (as defined herein) proceedings announced by the AUC (as defined herein) and the BCUC (as defined herein); the rate application proceedings announced by the NSUARB (as defined herein); the PBR (as defined herein) proceedings announced by the AUC (as defined herein); expectations regarding planned expenditures and related investments and capital program from 2023 to 2027 and the expected capital spend in 2023, including the sources of financing for TSU's capital expenditures; expected fluctuations in the Company's working capital and the expected funding of the Company's capital program; the Company's objective for managing capital and its effects on rate base and return to investors; the payment of dividends to the Company's shareholder; the expected benefits of the Alaska Utilities Acquisition (as defined herein); plans for the operation of the Alaska Utilities Business (as defined herein) and investments to be made in the local community; the impact of the Alaska Utilities Acquisition in respect of TSU's business (including, without limitation, in respect of rate base and other characteristics) and on TSU's strategic plans; expectations regarding the draw down of the RDA (as defined herein) by EEI (as defined herein); expectations regarding the expiry of the CRP (as defined herein); the Natural Gas Rebate Program announced by the Government of Alberta; and expected impact of adopting ASUs (as defined herein) in the future on the Company's consolidated financial statements.

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Company including, without limitation: the success of the integration of the Alaska Utilities Business;

expected commodity supply, demand and pricing; that the Company will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; regulatory approvals and policies; funding operating and capital costs; project completion dates; capacity expectations; that there will be no material defaults by the counterparties to agreements with the Company and such agreements will not be terminated prior to their scheduled expiry; and the Company will continue to have access to wind and water resources in amounts consistent with the amounts expected by the Company. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information and statements, including, without limitation: changes in the demand for or supply of the Company's services; unanticipated operating results; changes in regulatory matters; limited, unfavourable or a lack of access to capital markets; increased costs; the impact of competitors; attracting and retaining skilled personnel and certain other risks (including, without limitation, those risks identified elsewhere in this MD&A); and the other factors discussed under the heading *"Risk Factors"* in the Annual Information Form and set out in the Company's other continuous disclosure documents.

The Company believes the forward-looking statements in this MD&A are reasonable. However, such statements are not a guarantee that any of the actions, events or results of the forward-looking statements will occur, or if any of them do occur, their timing or what impact they will have on the Company's results of operations or financial condition. Because of these uncertainties, investors should not put undue reliance on any forward-looking statements.

The forward-looking statements included in this MD&A are expressly qualified by this cautionary statement and are made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by Canadian securities laws.

Additional information relating to the Company, including the Annual Information Form, is available on SEDAR at *www.sedar.com.*

ACQUISITION OF THE ALASKA UTILITIES BUSINESS

On March 1, 2023, Alaska Utility Holdings Inc. ("AUHI"), a subsidiary of the Company, completed the acquisition of a 100 percent interest in ENSTAR Natural Gas Company, LLC, the Alaska Pipeline Company, LLC and the Norstar Pipeline Company, Inc. (collectively, "ENSTAR"), and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") (collectively, the "Alaska Utilities Business") from a subsidiary of AltaGas Ltd., in an all cash transaction valued at approximately US$800 million, before customary post-closing adjustments (the "Alaska Utilities Acquisition"). As at February 28, 2023, CINGSA had approximately US$45 million (approximately US$29 million proportionate share) of outstanding senior notes which remain in place.

The Alaska Utilities Acquisition was financed using: (i) US$471 million of equity; (ii) net proceeds from the private placement offering of senior unsecured notes in three series totaling US$165 million; (iii) partial net proceeds of US$100 million ($135 million) from the issuance of medium-term notes ("MTNs") in January 2023; and (iv) borrowings from the Company's credit facilities. See Capital Resources section for additional information on the private placement and MTNs.

ENSTAR is the largest gas utility in the State of Alaska, servicing approximately 60 percent of the State's population, with approximately 150,000 customers and 3,626 miles of transmission and distribution pipeline. CINGSA, located in Kenai, Alaska, is the only commercial, fully contracted, state regulated gas storage facility in Alaska.

ENSTAR and the 65 percent interest in CINGSA had 2022 combined average rate base of approximately US$350 million. In 2022, ENSTAR's approved regulated ROE was 11.875 percent with an approved deemed capital structure of 51.8 percent equity, and effective August 19, 2022, CINGSA's approved regulated ROE was 10.60 percent with an approved deemed capital structure of 59.99 percent equity. Combined, ENSTAR and 100 percent of CINGSA's 2020-2022 three-year historical normalized EBITDA was approximately US$60 - $65 million per annum and normalized funds from operations was approximately US$45 - $50 million per annum. Normalized EBITDA and normalized funds from operations are non-GAAP financial measures, please see cautionary statement under the "Non-GAAP Financial Measures" section of this MD&A.

The closing of the Alaska Utilities Acquisition increased the Company's scale and capacity, growing TSU's consolidated rate base by approximately 40 percent to over $1.5 billion, and more than doubling its customer base. TSU believes ENSTAR has growth potential and intends to work closely with ENSTAR management to invest and support economic growth in the region. The Alaska Utilities Acquisition will also provide greater geographical and business diversification. Upon closing of the Alaska Utilities Acquisition, TSU now operates in multiple distinct regulatory jurisdictions in Canada and the United States.

THE COMPANY

TSU is incorporated under the *Canada Business Corporations Act* and its registered office and principal place of business is in Calgary, Alberta. TSU is a wholly-owned subsidiary of TriSummit Cycle Inc., a company in which the Public Sector Pension Investment Board indirectly holds a majority economic interest and Alberta Investment Management Corporation indirectly holds a minority economic interest.

As at December 31, 2022, the Company owns and operates rate-regulated distribution and transmission utility businesses through its wholly-owned operating subsidiaries Apex Utilities Inc. ("AUI") in Alberta, Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)") in British Columbia and Eastward Energy Incorporated (formerly Heritage Gas Limited) ("EEI") in Nova Scotia. The Company also owns the Bear Mountain Wind Park, an approximately 10 percent indirect interest in the Northwest Hydro Facilities, and a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories.

Upon the closing of the Alaska Utilities Acquisition on March 1, 2023, TSU's utility businesses also include wholly-owned operating subsidiaries ENSTAR Natural Gas Company, LLC and the Alaska Pipeline Company, LLC as well as a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC.

VISION, MISSION AND STRATEGY

The Company's vision is to be a premier growing North American utility and renewable energy company. The Company's mission is to be a reliable and cleaner energy provider of choice through being a leader in safety, cost effectiveness, and customer service. To achieve its vision and mission, the Company's strategy is to make disciplined, smart expansion choices that are consistent with a transitioning energy industry while safeguarding its existing businesses and driving organic growth within them.

2022 FINANCIAL HIGHLIGHTS

(Normalized EBITDA, normalized funds from operations, normalized net income, net debt, and net debt to total capitalization ratio are non-GAAP financial measures. Please see the *"Non-GAAP Financial Measures"* section of this MD&A.)

- Net income after taxes was $36.6 million, compared to $51.2 million in 2021.
- Normalized net income was $50.5 million, compared to $49.0 million in 2021.
- Operating income was $66.0 million, compared to $81.7 million in 2021.
- Normalized EBITDA was $127.1 million, compared to $123.8 million in 2021.
- Cash from operations was $104.2 million, compared to $95.4 million in 2021.
- Normalized funds from operations was $97.0 million, compared to $92.3 million in 2021.
- Net debt was $858.8 million as at December 31, 2022, compared to $768.5 million as at December 31, 2021.
- Net debt to total capitalization ratio was 57.6 percent as at December 31, 2022, compared to 55.0 percent as at December 31, 2021.
- Rate base as at December 31, 2022 was $1,192 million inclusive of construction work-in-progress, compared to $1,080 million as at December 31, 2021.
- On December 21, 2022, the Regulatory Commission of Alaska approved the acquisition of the Alaska Utilities Business and the Alaska Utilities Acquisition closed on March 1, 2023.
- On November 30, 2022, PNG filed a 2023 to 2024 revenue requirements application with the British Columbia Utilities Commission ("BCUC") seeking approval of interim customer delivery rates.
- In November 2022, the BCUC approved PNG's 2022 revenue requirements application.
- On September 28, 2022, TSU amended its $200 million unsecured syndicated revolving credit facility to increase the borrowing capacity to $235 million and extended the maturity date to September 28, 2026.
- On September 28, 2022, TSU amended its $35 million revolving operating credit facility to increase the borrowing capacity to $60 million.
- On September 1, 2022, the Alberta Utilities Commission ("AUC") issued a decision with respect to AUI's 2023 cost of service application that largely accepted the approach used by AUI to arrive at its 2023 cost forecasts.
- On August 15, 2022, TSU completed the issuance of $100 million MTNs with a coupon rate of 5.28 percent (5.288 percent yield to maturity) and a maturity date of August 15, 2052.
- On April 1, 2022, the BCUC accepted PNG's biomethane purchase agreements ("BPAs") with ATCO Future Fuel RNG Limited Partnership ("ATCO") and Tidal Energy Marking Inc. ("Tidal") as meeting the requirements for a prescribed undertaking as defined by B.C.'s *Greenhouse Gas Reduction (Clean Energy) Regulation*. On November 25, 2022, the BCUC approved a low carbon energy ("LCE") cost recovery mechanism for PNG.
- On March 31, 2022, the AUC issued a decision approving the extension of the current ROE of 8.5 percent and equity thickness of 39 percent for AUI for 2023.

HIGHLIGHTS SUBSEQUENT TO YEAR END

- On March 1, 2023, the Company completed the acquisition of the Alaska Utilities Business valued at approximately US$800 million, before customary post-closing adjustments.
- On March 1, 2023, AUHI completed a private placement offering of senior unsecured notes in three series totaling US$165 million:(i) series A senior unsecured notes in the aggregate principal amount of US$50 million that carry a coupon rate of 5.34 percent and mature on December 15, 2027; (ii) series B senior unsecured notes in the aggregate principal amount of US$25 million that carry a coupon rate of 5.38 percent and mature on March 31, 2030; and (iii) series C senior unsecured notes in the aggregate principal amount of US$90 million that carry a coupon rate of 5.41 percent and mature on March 31, 2033 (collectively, the "AUHI Notes").
- In February 2023, TriSummit Cycle Inc. contributed approximately $631.1 million (US$471 million) of equity to fund a portion of the Alaska Utilities Acquisition.
- In February 2023, TSU entered into a foreign exchange swap contract to sell US$100 million for 1.3386 Canadian per U.S. dollar in order to hedge the foreign currency exposure related to the Alaska Utilities Business.

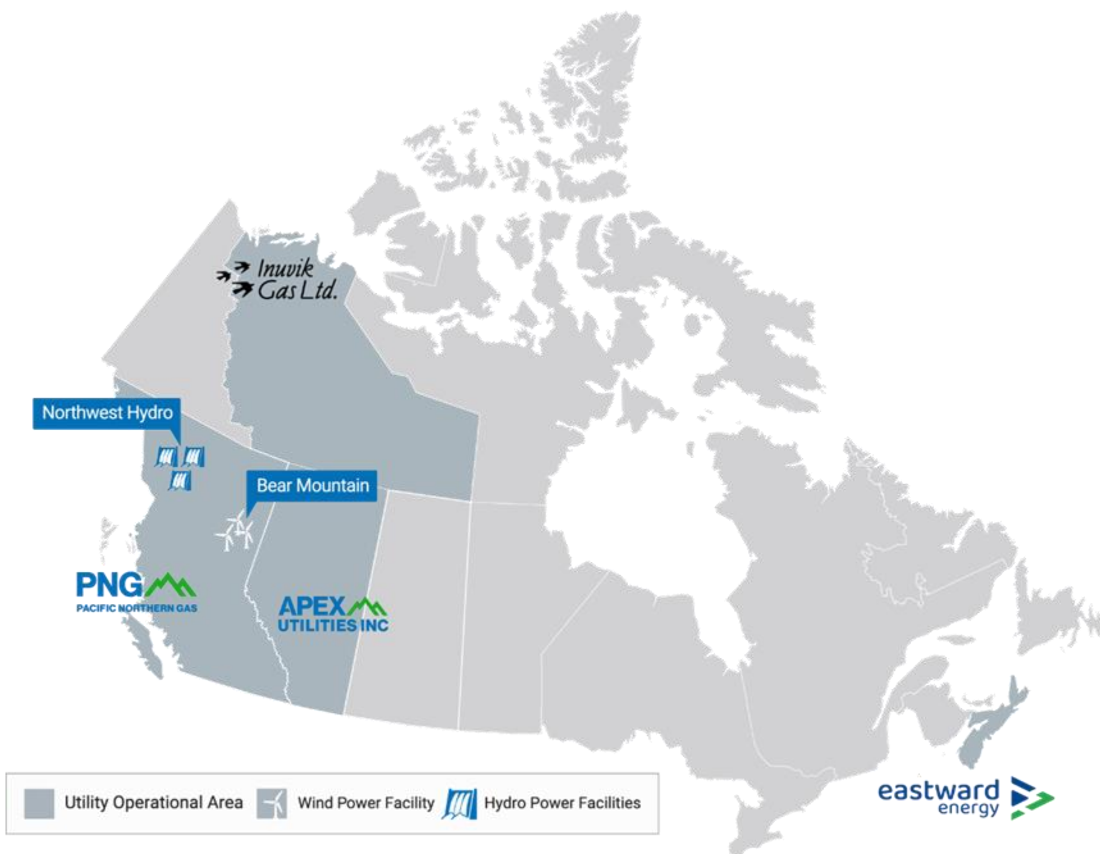
- On January 11, 2023, TSU completed the issuance of $200 million MTNs with a coupon rate of 5.02 percent (5.026 percent yield to maturity) and a maturity date of January 11, 2030.
- On January 16, 2023, EEI filed its 2024 to 2026 general rate application with the Nova Scotia Utility and Review Board ("NSUARB").

OVERVIEW OF THE BUSINESS

TSU has three reporting segments:

- Utilities, which owns and operates rate-regulated distribution and transmission assets in Alberta, British Columbia and Nova Scotia. TSU also owns a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. In aggregate, the utilities had approximately $1,192 million of rate base as at December 31, 2022 inclusive of construction work-in-progress and serve approximately 134,000 customers across Canada. Subsequent to the closing of the Alaska Utilities Acquisition on March 1, 2023, TSU's Utilities segment also includes the results from the operations of ENSTAR and CINGSA.
- Renewable Energy, which includes the 102 MW Bear Mountain Wind Park and an approximately 10 percent indirect interest in the 303 MW Northwest Hydro Facilities.
- Corporate, which primarily includes the cost of providing shared services, financing and access to capital, general corporate support as well as the equity investment in the NGIF Cleantech Ventures Limited Partnership.

Utilities segment



Alberta

AUI owns and operates a regulated natural gas distribution utility in Alberta. As at December 31, 2022, AUI served approximately 82,800 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. AUI's rate base as at December 31, 2022 was approximately $473 million.

For 2022 and 2021, AUI's approved ROE was 8.5 percent on 39 percent equity. On January 3, 2022, the AUC initiated a GCOC proceeding to establish the 2023 GCOC parameters for ROE and equity ratios (Stage 1), and address 2024 and future years (Stage 2). On March 31, 2022, the AUC issued a decision for Stage 1 approving the extension of the current ROE of 8.5 percent and equity thickness of 39 percent for AUI for 2023. On June 29, 2022, the AUC initiated Stage 2 of the proceeding to establish the approach for setting ROE for 2024 and beyond and to consider whether any changes are required to the cost-of-capital parameters.

AUI operates in a stable regulatory environment under a Performance-Based Regulation ("PBR") framework, first introduced for the initial 2013 to 2017 PBR plan term. Effective January 1, 2018, the AUC approved a second PBR plan term from 2018 to 2022 ("PBR 2"). Under the PBR 2 plan, rates continue to be set under a revenue cap per customer formula with annual adjustments for customer growth and inflation less expected productivity improvements. As revenues are generally decoupled from costs, a utility is incentivized to achieve cost efficiencies during the PBR plan term.

In addition, the PBR 2 plan continues to allow for recovery of costs determined to flow through directly to customers, recovery of items related to material exogenous events, and re-opener threshold provisions that allow an application to be re-opened in order to address specific problems with the design or operation of the PBR plan. Incremental capital funding is largely determined formulaically based on historical capital additions with an additional mechanism available for cost recovery of specific capital projects that are extraordinary, not previously included in rate base, and required by a third party ("Type 1 Capital Tracker"). As a result of its formulaic design, the PBR framework provides a level of regulatory certainty throughout the PBR period, allowing the utility to manage its costs and to allocate and plan capital spending accordingly.

On September 1, 2022, the AUC issued a decision with respect to AUI's 2023 cost of service application and confirmed that the rates approved for 2023 on a forecast basis will serve as going-in-rates for the third PBR term ("PBR 3") which will commence on January 1, 2024. In the decision, the AUC largely accepted the approach used by AUI to arrive at its 2023 cost forecasts. A compliance filing to reflect the directions and findings of the decision was filed by AUI on October 3, 2022 and a decision was issued on December 15, 2022.

In 2022, the AUC initiated a proceeding for PBR 3 to be effective January 1, 2024. The scope of the proceeding will consider parameters from PBR 2 to be retained, modified, removed, or added. On September 16, 2022, the AUC released its ruling on the final list of issues for the proceeding with initial evidence being filed on January 27, 2023.

On November 5, 2021, the Government of Alberta released the Hydrogen Roadmap identifying the province as being well positioned to participate in the global hydrogen economy, with the province enabling hydrogen blending into natural gas distribution systems as one method to reduce greenhouse gas emissions. Upon the direction of the Minister of Energy, the AUC opened an inquiry on matters related to hydrogen blending in natural gas distribution systems. Written comments from inquiry participants, including AUI, were submitted in April 2022, and the AUC's report to the Minister of Energy was submitted on June 30, 2022 and publicly released on September 6, 2022.

On July 6, 2022, the Government of Alberta released preliminary details of a Natural Gas Rebate Program, which will be funded by the Province of Alberta, to help consumers manage higher winter heating costs. The rebate threshold is an absolute rate cap that will be triggered when the monthly gas cost recovery rate for any of Alberta's three regulated utility providers is above $6.50 per GJ. On December 7, 2022, the Government of Alberta announced the Natural Gas Rebate Program will be extended beyond its original October 1, 2022 to March 31, 2023 timeframe with details to be included once forthcoming regulations are tabled in 2023.

British Columbia

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (the "Western System") and PNG(N.E.), PNG's wholly-owned subsidiary, owns and operates a distribution utility in northeastern British Columbia (the "Northeast System"). As at December 31, 2022, PNG served approximately 42,400 customers. Approximately 87 percent of PNG's total customers are residential. PNG's rate base as at December 31, 2022 was approximately $391 million.

PNG operates under a cost of service regulatory framework affording PNG an opportunity to recover all prudently incurred costs and earn a rate of return on its deemed common equity. The allowed ROE and deemed capital structure is approved by the BCUC and is based off the low risk benchmark utility. The allowed ROE for the Western System and the Northeast System (Tumbler Ridge) is 9.50 percent and for the Northeast System (Fort St. John/Dawson Creek) is 9.25 percent. The approved common equity ratio for the Western System and the Northeast System (Tumbler Ridge) is 46.5 percent and for the Northeast System (Fort St. John/Dawson Creek) is 41 percent. In January 2021, the BCUC announced the initiation of a GCOC proceeding to address the appropriate common equity component and return on equity for the utilities it regulates. The BCUC is currently reviewing the common equity component and return on equity for each of the FortisBC gas and electric utilities and assessing which utility will serve as the appropriate benchmark utility. Once the benchmark utility has been established, the BCUC will conduct a review of other utilities, including PNG, to determine their applicable common equity component and return on equity; these reviews are expected to be completed in 2023.

On July 8, 2021, the BCUC granted approval of the certificate of public convenience and necessity ("CPCN") application filed by PNG on October 2, 2020, for a project to repair and refurbish part of its Western System, specifically an 80-kilometer segment of the 8-inch transmission line between Terrace, British Columbia, and Prince Rupert, British Columbia (the "Salvus to Galloway Project"). The project is required to address the integrity condition of aging infrastructure and to ensure long-term reliable supply. Project work will be conducted within the existing PNG corridor and nearby permitted temporary workspace. The expected capital cost for the Salvus to Galloway Project is approximately $85 million, to be incurred over a four-year period, between 2021 and 2024. Following BCUC approval, construction began in the summer of 2021 and will continue in phases with completion expected in the fall of 2024. As at December 31, 2022, $51.4 million of capital expenditures have been incurred on the Salvus to Galloway Project.

On November 30, 2021, the BCUC granted approval of the application for a CPCN filed by PNG on March 5, 2021, for costs related to system reactivation and recommissioning work necessary to return the existing Western System back to the contracted utilization capacity (the "PNG Reactivation Project"). PNG currently expects to incur approximately $49 million of the BCUC approved maximum $89 million for the capital costs on the PNG Reactivation Project. These capital costs are required to meet existing contracted demand and will be incurred over a four-year period, between 2021 and 2024. Following BCUC approval, construction began in the fourth quarter of 2021. As at December 31, 2022, $16.9 million of capital expenditures have been incurred on the PNG Reactivation Project.

On September 10, 2021, Port Edward LNG Ltd. ("Port Edward LNG"), a party to certain transportation and service agreements with PNG, received approval from the British Columbia Energy Regulator ("BCER") (formerly British Columbia Oil and Gas Commission) for its LNG project in Port Edward, British Columbia. Port Edward LNG subsequently received approval from the BCER on March 17, 2022, for an amendment to incorporate the second phase of its LNG project. Under the terms of PNG's transportation and service agreements with Port Edward LNG, demand charges commenced in December 2022.

In November 2022, the BCUC approved PNG's 2022 revenue requirements application, which included the determination of final customer delivery rates for 2022.

On November 30, 2022, PNG submitted its 2023 and 2024 revenue requirement applications seeking interim rate increases effective January 1, 2023. On December 16, 2022, the BCUC approved the 2023 delivery rates on an interim and refundable/recoverable basis. Amendments to the applications were filed in February 2023 and PNG expects the BCUC decision on permanent rates for 2023 and 2024 in the third quarter of 2023.

On April 1, 2022, the BCUC accepted PNG's BPAs with ATCO and Tidal as meeting the requirements for a prescribed undertaking as defined by B.C.'s *Greenhouse Gas Reduction (Clean Energy) Regulation*. This approval exempts the BPAs from regulatory review as to whether they are in the public interest. The BPAs provide biomethane supply for PNG's LCE program in support of the greenhouse gas reduction goals of PNG, its customers, and the Province of British Columbia. On November 25, 2022, the BCUC approved a LCE cost recovery mechanism for PNG.

Nova Scotia

EEI has the exclusive rights to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality. As at December 31, 2022, EEI's customer base is approximately 8,800 customers. EEI has a mix of residential, small commercial, large commercial and industrial customers. EEI's rate base as at December 31, 2022 was approximately $328 million.

EEI operates under a cost of service regulatory framework where prudently incurred investments earn a rate of return on its deemed capital structure which is approved by the NSUARB. For 2022 and 2021, EEI's approved regulated ROE was 11 percent with an approved deemed capital structure of 45 percent equity.

In September 2016, the NSUARB approved EEI's Customer Retention Program ("CRP") application allowing EEI to reduce the base energy charges for customers who consume between 500 and 4,999 GJs per year and the flexibility to increase the base energy charges up to $8.69 per GJ (the previously approved rates), deferral of depreciation expense and a deferral of an additional approximately 25 percent of maintenance and administrative expenses while the program is in place. Effective January 1, 2020, the CRP deferral mechanism was changed to defer amounts equivalent to the price discount provided to certain small commercial customers, rather than suspending depreciation and deferring a portion of operating, maintenance and administrative expenses. The deferred amounts under the CRP earn a return of 4 percent. The CRP program is scheduled to expire on December 31, 2023. EEI exercised the flexibility provided for in the CRP to gradually increase the rates that were previously reduced as part of the CRP from $3.10 per GJ in 2017 to the current rate of $7.10 per GJ in 2022. EEI has forecasted to return to the previously approved cost of service levels by the end of 2023.

For its regulated operations, EEI has approval from the NSUARB to use a Revenue Deficiency Account ("RDA") until it is fully recovered, subject to a maximum of $50 million, which may be increased subject to approval by the NSUARB. The RDA is revenue required to afford EEI the opportunity to earn the rates of return on its rate base, as approved by the NSUARB. In periods where the actual revenue billed is less than the revenue required to earn the approved rates of return, the RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rates of return and the RDA is drawn down.

On January 16, 2023, EEI filed its 2024 to 2026 general rate application with the NSUARB for new customer rates effective January 1, 2024 to December 31, 2026. The NSUARB has issued a board order for the public hearing to take place starting on June 12, 2023.

Inuvik Gas Ltd. & Ikhil Joint Venture

The Company has an approximate one third interest in Inuvik Gas Ltd. ("Inuvik Gas") and the Ikhil Joint Venture natural gas reserves, which helps supply Inuvik Gas with natural gas for the Town of Inuvik.

Renewable Energy Segment

Bear Mountain Wind Park

The Bear Mountain Wind Park near Dawson Creek, British Columbia is a 102 MW generating wind facility consisting of 34 turbines, a substation and transmission and collector lines, which is connected to the BC Hydro transmission grid. All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year electricity purchase agreement (“EPA”) expiring in 2034 with an escalation factor of 50 percent of Canadian CPI.

Northwest Hydro Facilities

The Northwest Hydro Facilities, in which the Company has a 10 percent indirect equity interest, are located in Tahltan First Nation territory approximately 1,000 kilometers northwest of Vancouver, British Columbia, and are comprised of the Forrest Kerr Hydroelectric Facility (“Forrest Kerr”), the McLymont Creek Hydroelectric Facility (“McLymont Creek”), the Volcano Creek Hydroelectric Facility (“Volcano Creek”) and a substation and transmission line and related facilities. The facilities have total installed capacity of 303 MW. These facilities are each underpinned by 60-year EPAs, fully indexed to BC CPI. The EPAs for Forrest Kerr and Volcano Creek expire in 2074, and the EPA for McLymont Creek expires in 2075. Impact benefit agreements are in place with the Tahltan First Nation for all three facilities, to facilitate a cooperative and mutually beneficial long-term relationship.

CAPITAL PROGRAM GUIDANCE

Over the 2023 to 2027 time period, TSU expects capital investments of up to $1.1 billion at its Utilities. The expected capital program includes investments in the recently acquired Alaska Utilities Business, PNG Reactivation Project and the Salvus to Galloway Project, as well as investments in system betterment projects to maintain the safety and reliability of TSU’s utility infrastructure, new business opportunities, technology improvements, and energy transition investments. In 2023, TSU expects capital investments to be in the range of $200 to $220 million.

SEASONALITY

Results for the Utilities segment have a high degree of seasonality associated with them as the second and third quarters usually produce lower net income as a result of warmer weather, lower customer demand, and certain expenses such as depreciation, operating and administrative expenses, and interest expense, which generally increase as a result of rate base growth and are more evenly distributed throughout the year. These increased costs are normally more than offset in the first and fourth quarters which produce higher net income as a result of colder weather and higher customer demand.

SELECTED FINANCIAL INFORMATION

The following tables summarize key financial results:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2022**	2021	**2022**	2021
Normalized EBITDA[1]	**43.4**	39.7	**127.1**	123.8
Operating income	**11.2**	28.7	**66.0**	81.7
Net income after taxes	**1.9**	21.0	**36.6**	51.2
Normalized net income[1]	**23.6**	20.9	**50.5**	49.0
Total assets	**1,917.4**	1,748.7	**1,917.4**	1,748.7
Total long-term liabilities	**1,055.6**	1,010.6	**1,055.6**	1,010.6
Net additions to property, plant and equipment	**50.6**	55.7	**149.0**	111.3
Dividends declared	**9.3**	8.8	**35.6**	33.5
Cash from operations	**26.6**	20.7	**104.2**	95.4
Normalized funds from operations[1]	**37.4**	36.9	**97.0**	92.3

	Three Months Ended December 31		Year Ended December 31	
($ per Common Share, except Common Shares outstanding)	**2022**	2021	**2022**	2021
Net income after taxes - basic and diluted	**0.06**	0.70	**1.22**	1.71
Normalized net income - basic[1]	**0.79**	0.70	**1.68**	1.63
Cash from operations	**0.89**	0.69	**3.47**	3.18
Normalized funds from operations[1]	**1.25**	1.23	**3.23**	3.08
Weighted average number of Common Shares outstanding - basic (millions)	**30.0**	30.0	**30.0**	30.0

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

The following table summarizes TSU's consolidated results:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2022**	2021	**2022**	2021
Revenue	**153.8**	130.8	**465.3**	377.1
Cost of sales	**(82.6)**	(63.1)	**(230.4)**	(154.8)
Operating and administrative expense	**(33.1)**	(29.6)	**(125.4)**	(108.8)
Accretion expense	**(0.1)**	(0.1)	**(0.2)**	(0.3)
Depreciation and amortization expense	**(11.1)**	(10.1)	**(44.7)**	(40.2)
Income from equity investments	**0.7**	0.7	**5.8**	6.3
Unrealized gain (loss) on risk management contracts	**(17.0)**	0.1	**(6.9)**	2.2
Other income	**0.6**	0.1	**2.5**	0.5
Foreign exchange loss	**—**	(0.1)	**—**	(0.3)
Operating income	**11.2**	28.7	**66.0**	81.7
Interest expense	**(8.9)**	(7.2)	**(31.8)**	(28.1)
Income tax recovery (expense)	**(0.4)**	(0.5)	**2.4**	(2.4)
Net income after taxes	**1.9**	21.0	**36.6**	51.2

Three Months Ended December 31

Normalized EBITDA for the three months ended December 31, 2022 was $43.4 million, an increase of $3.7 million relative to the same period in 2021 primarily due to higher approved rates and rate base growth at the Utilities, colder weather compared to the same period in 2021 in Alberta, and higher normalized EBITDA from the Northwest Hydro Facilities, partially offset by lower generation at the Bear Mountain Wind Park, warmer weather in Nova Scotia compared to the same period in 2021 and higher operating and administrative expense.

Operating income for the three months ended December 31, 2022 was $11.2 million, a decrease of $17.5 million relative to the same period in 2021 primarily due to an unrealized loss on risk management contracts compared to an unrealized gain in the same period in 2021, higher depreciation and amortization expense, and transaction costs of approximately $2.6 million incurred related to the Alaska Utilities Acquisition, partially offset by the same factors as the increase in normalized EBITDA discussed above.

Operating and administrative expense for the three months ended December 31, 2022 was $33.1 million, an increase of $3.5 million from the same period in 2021 mainly due to transaction costs of approximately $2.6 million incurred related to the Alaska Utilities Acquisition and higher employee and consulting expenses.

Depreciation and amortization expense for the three months ended December 31, 2022 was $11.1 million, an increase of $1.0 million from the same period in 2021 primarily due to rate base growth.

Interest expense for the three months ended December 31, 2022 was $8.9 million compared to $7.2 million in the same period in 2021. The increase of $1.7 million was mainly due to a higher average debt balance outstanding and higher average interest rate.

Income tax expense for the three months ended December 31, 2022 was $0.4 million, compared to $0.5 million in the same period in 2021 primarily due to higher capital cost allowance deductions at the Utilities.

Normalized net income for the three months ended December 31, 2022 was $23.6 million, compared to $20.9 million in the same period in 2021. The increase in normalized net income was mainly due to the same factors as the increase in normalized EBITDA discussed above, partially offset by higher depreciation and amortization expense and higher interest expense.

Net income after taxes for the three months ended December 31, 2022 was $1.9 million, compared to $21.0 million in the same period in 2021 primarily due to the same factors as the decrease in operating income discussed above and higher interest expense.

Normalized funds from operations for the three months ended December 31, 2022 was $37.4 million compared to $36.9 million in the same period in 2021 primarily due to the same factors impacting normalized EBITDA discussed above, higher distributions from the Company's investment in the Northwest Hydro Facilities, partially offset by higher current income tax expense and interest expense.

Please refer to the "*Liquidity and Capital Resources - Liquidity"* section of this MD&A for a discussion of changes in cash from operating activities.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2022 was $127.1 million, an increase of $3.3 million from the same period in 2021, mainly due to higher approved rates and rate base growth at the Utilities and colder weather in Alberta compared to the same period in 2021, partially offset by lower revenues from the Bear Mountain Wind Park and higher operating and administrative expense.

Operating income for the year ended December 31, 2022 was $66.0 million, a decrease of $15.7 million from the same period in 2021, mainly due to an unrealized loss on risk management contracts compared to an unrealized gain in the same period in 2021, higher depreciation and amortization expense, higher costs incurred to support business development activities, and transaction costs of approximately $5.3 million incurred related to the Alaska Utilities Acquisition, partially offset by the same factors as the increase in normalized EBITDA discussed above.

Operating and administrative expense for the year ended December 31, 2022 was $125.4 million, an increase of $16.6 million from the same period in 2021, mainly due to higher costs incurred to support business development activities, transaction costs of approximately $5.3 million incurred related to the Alaska Utilities Acquisition, and higher employee and consulting expenses.

Depreciation and amortization expense for the year ended December 31, 2022 was $44.7 million, an increase of $4.5 million from the same period in 2021 mainly due to rate base growth.

Interest expense for the year ended December 31, 2022 was $31.8 million compared to $28.1 million in the same period in 2021. The increase of $3.7 million was mainly due to a higher average debt balance outstanding and higher average interest rate.

Income tax recovery for the year ended December 31, 2022 was $2.4 million, compared to income tax expense of $2.4 million in the same period in 2021. The decrease in income tax expense was primarily due to lower taxable income as a result of higher capital cost allowance deductions at the Utilities and higher costs incurred on business development activities.

Normalized net income for the year ended December 31, 2022 was $50.5 million, an increase of $1.5 million relative to the same period in 2021 mainly due to the same factors as the increase in normalized EBITDA discussed above and lower income tax expense, partially offset by higher depreciation and amortization expense and higher interest expense.

Net income after taxes for the year ended December 31, 2022 was $36.6 million, a decrease of $14.6 million compared to the same period in 2021. The decrease was primarily due to the same factors as the decrease in operating income discussed above and higher interest expense, partially offset by lower income tax expense.

Normalized funds from operations for the year ended December 31, 2022 was $97.0 million, an increase of $4.7 million relative to the same period in 2021, primarily due to the same factors impacting EBITDA discussed above and lower current income tax expense, partially offset by higher interest expense and lower distributions from the Northwest Hydro Facilities.

Please refer to the "*Liquidity and Capital Resources - Liquidity"* section of this MD&A for a discussion of changes in cash from operating activities.

RESULTS BY REPORTING SEGMENT

Normalized EBITDA by Reporting Segment[1]

($ millions)	Three Months Ended December 31 2022	2021	Year Ended December 31 2022	2021
Utilities	**$ 39.8**	$ 35.7	**$ 115.4**	$ 103.9
Renewable Energy	**5.5**	5.7	**22.4**	23.9
Corporate	**(1.9)**	(1.7)	**(10.7)**	(4.0)
	$ 43.4	$ 39.7	**$ 127.1**	$ 123.8

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

Operating Income (Loss) by Reporting Segment

($ millions)	Three Months Ended December 31 2022	2021	Year Ended December 31 2022	2021
Utilities	**$ 14.3**	$ 27.3	**$ 62.7**	$ 72.9
Renewable Energy	**2.1**	3.1	**11.0**	12.9
Corporate	**(5.3)**	(1.7)	**(7.7)**	(4.1)
	$ 11.1	$ 28.7	**$ 66.0**	$ 81.7

UTILITIES SEGMENT REVIEW

Financial results

($ millions)	Three Months Ended December 31 2022	2021	Year Ended December 31 2022	2021
Revenue	**$ 148.9**	$ 125.0	**$ 447.4**	$ 357.2
Cost of sales	**(82.5)**	(63.0)	**(230.1)**	(154.5)
Operating and administrative expense	**(27.3)**	(26.5)	**(104.5)**	(99.4)
Normalized EBITDA from equity investment	**0.1**	0.1	**0.1**	0.1
Other income	**0.6**	0.1	**2.5**	0.5
Normalized EBITDA[1]	**$ 39.8**	$ 35.7	**$ 115.4**	$ 103.9
Unrealized gain (loss) on risk management contracts	**(16.2)**	0.1	**(15.3)**	2.2
Depreciation and amortization expense	**(9.3)**	(8.4)	**(37.3)**	(32.8)
Foreign exchange loss	**—**	(0.1)	**—**	(0.3)
Accretion expense	**—**	—	**(0.1)**	(0.1)
Operating income	**$ 14.3**	$ 27.3	**$ 62.7**	$ 72.9

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

Operating statistics

	Three Months Ended December 31 2022	2021	Year Ended December 31 2022	2021
Natural gas deliveries - end-use (PJ)	**11.6**	11.5	**34.1**	33.3
Natural gas deliveries - transportation (PJ)	**1.6**	1.5	**5.8**	5.4
Degree day variance from normal - AUI (%)[1]	**9.8**	6.0	**0.2**	(0.3)
Degree day variance from normal - EEI (%)[1]	**(15.0)**	(7.4)	**(8.6)**	(9.3)

(1) A degree day for AUI and EEI is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at EEI. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG, as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

Regulatory Metrics

Year ended December 31	**2022**	2021
Weighted - average approved ROE (%)(1)	**9.1**	9.1
Rate base ($ millions)(2)(3)	**1,192**	1,080

(1) ROE is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base.

(2) Rate base is indicative of the earning potential of each utility over time. Approved revenue requirements for each utility is typically based on the rate base as approved by the regulator for the respective rate application, but may differ from the rate base indicated above.

(3) Inclusive of construction work in progress.

Three Months Ended December 31

Revenue increased by $23.9 million for the three months ended December 31, 2022 as compared to the same period in 2021 primarily due to higher approved rates and rate base growth, flow through of higher gas supply costs to customers, and colder weather compared to the same period in 2021 in Alberta, partially offset by warmer weather compared to the same period in 2021 in Nova Scotia.

Normalized EBITDA increased by $4.1 million for the three months ended December 31, 2022 as compared to the same period in 2021, primarily due to higher approved rates and rate base growth and colder weather in Alberta compared to the same period in 2021, partially offset by warmer weather in Nova Scotia compared to the same period in 2021.

Operating income decreased by $13.0 million for the three months ended December 31, 2022 as compared to the same period in 2021, primarily due to an unrealized loss on risk management contracts compared to an unrealized gain in the same period in 2021 and higher depreciation and amortization expense due to rate base growth, partially offset by the increase in normalized EBITDA discussed above.

Year Ended December 31

Revenue increased by $90.2 million for the year ended December 31, 2022 as compared to the same period in 2021, primarily due to higher approved rates and rate base growth, flow through of higher gas supply costs to customers, and colder weather compared to the same period in 2021 in Alberta.

Normalized EBITDA increased by $11.5 million for the year ended December 31, 2022 as compared to the same period in 2021, primarily due to higher approved rates and rate base growth and colder weather compared to the same period in 2021 in Alberta, partially offset by higher salary and consulting expenses.

Operating income decreased by $10.2 million for the year ended December 31, 2022 as compared to the same period in 2021, primarily due to an unrealized loss on risk management contracts compared to an unrealized gain in the same period in 2021 and higher depreciation and amortization expense due to rate base growth, partially offset by the same factors as the increase in normalized EBITDA discussed above.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2022**	2021	**2022**	2021
Revenue	**$ 4.9**	$ 5.8	**$ 17.9**	$ 19.9
Cost of sales	**(0.1)**	(0.1)	**(0.3)**	(0.3)
Operating and administrative expense	**(1.3)**	(1.4)	**(5.1)**	(5.4)
Normalized EBITDA from equity investment	**2.0**	1.4	**9.9**	9.7
Normalized EBITDA(1)	**$ 5.5**	$ 5.7	**$ 22.4**	$ 23.9
Depreciation and amortization expense	**(1.8)**	(1.7)	**(7.3)**	(7.3)
Accretion expense	**(0.1)**	(0.1)	**(0.1)**	(0.2)
Accretion and depreciation and amortization expense from equity investment(2)	**(1.4)**	(0.8)	**(4.0)**	(3.5)
Operating income	**$ 2.2**	$ 3.1	**$ 11.0**	$ 12.9

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(2) Inclusive of TSU's proportionate share of unrealized loss of $0.5 million on remeasurement of the Northwest Transmission Line liability in relation to the equity investment in the Northwest Hydro Facilities for the three and twelve months ended December 31, 2022.

Operating statistics

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Bear Mountain Wind Park power sold (GWh)	**49.2**	56.9	**174.2**	191.4
Northwest Hydro Facilities power sold (GWh)(1)(2)	**25.0**	16.0	**120.1**	113.1

(1) Representing 10 percent of the total power sold by the Northwest Hydro Facilities.

(2) Inclusive of 3.0 GWh of deemed energy for the year ended December 31, 2022 related to BC Hydro's curtailment.

Three Months Ended December 31

Revenue decreased by $0.9 million for the three months ended December 31, 2022 as compared to the same period in 2021 primarily due to lower generation at the Bear Mountain Wind Park, partially offset by annual price escalation.

Normalized EBITDA decreased by $0.2 million for the three months ended December 31, 2022 as compared to the same period in 2021 primarily due to lower generation at the Bear Mountain Wind Park, partially offset by higher normalized EBITDA from the investment in the Northwest Hydro Facilities.

Operating income decreased by $0.9 million for the three months ended December 31, 2022 as compared to the same period in 2021 mainly due to the equity pickup of an unrealized loss of $0.5 million from the remeasurement of the Northwest Transmission Line liability in relation to the Northwest Hydro Facilities and due to the same factors as the decrease in normalized EBITDA discussed above.

During the three months ended December 31, 2022, TSU recorded $0.6 million of equity income from its investment in the Northwest Hydro Facilities, consistent with the same period in 2021.

Year Ended December 31

Revenue decreased by $2.0 million for the year ended December 31, 2022 as compared to the same period in 2021, primarily due to lower generation at the Bear Mountain Wind Park and lower sales of renewable energy certificates ("RECs"), partially offset by annual price escalation.

Normalized EBITDA decreased by $1.5 million for the year ended December 31, 2022 as compared to the same period in 2021, primarily due to lower revenues at the Bear Mountain Wind Park, partially offset by lower maintenance costs at the Bear Mountain Wind Park and higher normalized EBITDA from the Northwest Hydro Facilities.

Operating income decreased by $1.9 million for the year ended December 31, 2022 as compared to the same period in 2021 due to the same factors as the decrease in normalized EBITDA discussed above and the equity pickup of an unrealized loss of $0.5 million from the remeasurement of the Northwest Transmission Line liability in relation to the Northwest Hydro Facilities.

During the year ended December 31, 2022, TSU recorded $5.9 million of equity income from its investment in the Northwest Hydro Facilities, compared to $6.2 million in the same period in 2021. The decrease in equity income was mainly due to the absence of the BC Hydro arbitration settlement during the second quarter of 2021 and the unrealized loss on remeasurement of the Northwest Transmission Line liability in the fourth quarter of 2022, partially offset by higher generation and annual price escalation.

CORPORATE SEGMENT REVIEW

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2022**	2021	**2022**	2021
Operating and administrative expense	**$ (1.9)**	$ (1.7)	**$ (10.5)**	$ (4.0)
Normalized EBITDA from equity investment	**—**	—	**(0.2)**	—
Normalized EBITDA[1]	**$ (1.9)**	$ (1.7)	**$ (10.7)**	$ (4.0)
Depreciation and amortization	**—**	—	**(0.1)**	(0.1)
Unrealized gain (loss) on risk management contracts	**(0.8)**	—	**8.4**	—
Transaction costs	**(2.6)**	—	**(5.3)**	—
Operating loss	**$ (5.3)**	$ (1.7)	**$ (7.7)**	$ (4.1)

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

Expenses incurred by the Corporate segment are primarily associated with providing shared corporate services and business development. For the three and twelve months ended December 31, 2022, normalized EBITDA was a loss of $1.9 and $10.7 million, respectively (2021 - $1.7 and $4.0 million, respectively). The decrease in normalized EBITDA for the three and twelve months ended December 31, 2022, compared to the same periods in 2021 was primarily due to higher costs incurred to support business development activities and higher salaries and benefits.

For the three and twelve months ended December 31, 2022, corporate costs of $1.9 million and $7.9 million, respectively, were allocated to TSU's operating segments compared to $1.4 million and $6.4 million, respectively, for the same periods in 2021.

For the three months ended December 31, 2022, operating loss was $5.3 million compared to $1.7 million in the same period in 2021. The increase in operating loss was mainly due to the same factors as the decrease in normalized EBITDA discussed above, transaction costs of approximately $2.6 million incurred related to the Alaska Utilities Acquisition and an unrealized loss of $0.8 million on the deal contingent forward interest rate swap that the Company entered into in connection with the Alaska Utilities Acquisition. For the twelve months ended December 31, 2022, operating loss was $7.7 million compared to $4.1 million in the same period in 2021. The increase in operating loss was mainly due to the same factors as the decrease in normalized EBITDA discussed above and transaction costs of approximately $5.3 million incurred related to the Alaska Utilities Acquisition, partially offset by an unrealized gain of $8.4 million on the deal contingent forward interest rate swap that the Company entered into in connection with the Alaska Utilities Acquisition.

SUMMARY OF SELECTED QUARTERLY RESULTS(1)

The following table sets forth unaudited quarterly information for each of the eight quarters from the quarter ended March 31, 2021 to the quarter ended December 31, 2022.

($ millions, except per Common Share amounts)	**Q4-22**	Q3-22	Q2-22	Q1-22
Revenue	**153.8**	63.4	84.8	163.3
Normalized net income (loss)(2)	**23.6**	(1.4)	(1.2)	29.3
Net income (loss) after taxes	**1.9**	7.2	(1.4)	28.7
Net income (loss) after taxes per Common Share - basic and diluted ($)	**0.06**	0.24	(0.05)	0.96
Dividends declared per Common Share ($)(3)	**0.3100**	0.2925	0.2925	0.2925

($ millions, except per Common Share amounts)	Q4-21	Q3-21	Q2-21	Q1-21
Revenue	130.8	54.6	67.9	123.9
Normalized net income(2)	20.9	1.7	3.5	23.1
Net income after taxes	21.0	2.4	4.0	23.9
Net income after taxes per Common Share - basic and diluted ($)	0.70	0.08	0.13	0.80
Dividends declared per Common Share ($)(3)	0.2925	0.2750	0.2750	0.2750

(1) Amounts may not add due to rounding.

(2) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(3) TSU declares and pays a quarterly dividend on its Common Shares. Dividends are at the discretion of the board of directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of TSU.

Quarter-over-quarter financial results are impacted by seasonality, weather, planned and unplanned outages, and timing and recognition of regulatory decisions.

Revenue for the Utilities segment is generally the highest in the first and fourth quarters of any given year as the majority of customer demand occurs during the winter heating season, which typically extends from November to March.

Net income after taxes is affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, impairment, gains and losses on risk management contracts, and gains or losses on the sale of assets. For these reasons, net income may not necessarily reflect the same trends as revenue. In addition, the equity investment in the Northwest Hydro Facilities is impacted by seasonal precipitation, which creates periods of high river flow, typically during May through October of any given year.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

The Company's primary sources of liquidity are cash flow from operations and debt additions. The Company's cash requirements include funding for capital expenditures and working capital, servicing and repayment of long-term debt, and dividend payments. The Company's sources and uses of cash are further discussed below:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2022**	2021	**2022**	2021
Cash from operations	**$ 26.6**	$ 20.7	**$ 104.2**	$ 95.4
Cash used in investing activities	**(59.7)**	(51.9)	**(157.7)**	(112.4)
Cash from financing activities	**35.5**	35.4	**52.7**	15.8
Increase (decrease) in cash and cash equivalents	**$ 2.4**	$ 4.2	**$ (0.8)**	$ (1.2)

Cash from operations

During the three and twelve months ended December 31, 2022, cash from operations increased by $5.9 million and $8.8 million, respectively, as compared to the same periods in 2021 primarily due to higher cash earnings and favourable variance from changes in operating assets and liabilities. The favourable variance in changes in operating assets and liabilities were primarily due to timing of supplier payments.

Investing activities

During the three and twelve months ended December 31, 2022, cash used in investing activities increased by $7.8 million and $45.3 million, respectively, as compared to the same periods in 2021 primarily due to higher capital expenditures and contribution to the NGIF Cleantech Ventures Limited Partnership.

See also the "*Capital Expenditures"* section of this MD&A.

Financing activities

During the three and twelve months ended December 31, 2022, cash from financing activities increased by $0.1 million and $36.9 million, respectively, as compared to the same periods in 2021 primarily due to higher net borrowings, partially offset by an increase in dividends paid.

Working Capital

($ millions except current ratio)	**December 31, 2022**	December 31, 2021
Current assets	**$ 143.0**	$ 110.3
Current liabilities	**230.1**	109.8
Working capital (deficiency)	**$ (87.1)**	$ 0.5
Working capital ratio	**0.62**	1.00

The variation in the working capital was primarily due to a decrease in cash held and accounts receivable and an increase in short-term debt and current portion of long-term debt. TSU's working capital will fluctuate in the normal course of business, and the working capital deficiency will be funded using cash flow from operations and available credit facilities as required.

Capital Resources

The Company's objective for managing capital is to maintain its investment grade credit rating, ensure adequate liquidity, maximize the profitability of its existing assets and grow its business through prudent capital investments which ultimately add to the Utilities' rate base, and enhance returns to its shareholder. The Company's capital resources are comprised of short-term and long-term debt (including the current portion).

The use of debt or equity funding is based on TSU's capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

($ millions, except where noted)	**December 31, 2022**	December 31, 2021
Short-term debt	**$ 41.5**	$ —
Current portion of long-term debt	**25.9**	1.0
Long-term debt(1)	**796.5**	773.4
Total debt	**863.9**	774.4
Less: cash and cash equivalents	**(5.1)**	(5.9)
Net debt(2)	**$ 858.8**	$ 768.5
Shareholder's equity	**631.7**	628.3
Total capitalization	**$ 1,490.5**	$ 1,396.8
Net debt-to-total capitalization(2) (%)	**57.6**	55.0

(1) Net of debt issuance costs of $3.2 million as of December 31, 2022 (December 31, 2021 - $3.0 million).

(2) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

As at December 31, 2022, TSU's total debt primarily consisted of outstanding MTNs of $750.0 million (December 31, 2021 - $650.0 million), PNG debentures of $22.0 million (December 31, 2021 - $23.0 million) and $94.8 million drawn under other bank credit facilities (December 31, 2021 - $104.0 million). In addition, TSU had $10.7 million of letters of credit issued (December 31, 2021 - $8.3 million).

On January 11, 2023, TSU completed the issuance of $200 million of MTNs with a coupon rate of 5.02 percent and a maturity date of January 11, 2030. The net proceeds were used (i) as to approximately $135 million, to partially finance the Alaska Utilities Acquisition; and (ii) as to the remainder, to repay amounts outstanding under the syndicated revolving credit facility and operating credit facility, which amounts were incurred in the normal course of business to fund the working capital requirements of TSU.

On March 1, 2023, AUHI completed a private placement offering of the AUHI Notes. The net proceeds were used to partially finance the Alaska Utilities Acquisition.

TSU's earnings interest coverage for the rolling 12 months ended December 31, 2022 was 2.1 times (12 months ended December 31, 2021 - 2.9 times).

Credit Facilities

The Company funds its long and short term borrowing requirements with credit facilities as follows:

($ millions)	**Borrowing capacity**	**Drawn at December 31, 2022**	Drawn at December 31, 2021
Syndicated revolving credit facility(1)	$ **235.0**	$ **28.2**	$ 79.0
Operating credit facility(2)	**60.0**	**44.6**	3.2
PNG committed credit facility(3)	**25.0**	**25.0**	25.0
PNG operating credit facility(4)	**25.0**	**7.7**	5.1
	$ **345.0**	$ **105.5**	$ 112.3

(1) On September 28, 2022, the Company amended the facility to increase the borrowing capacity to $235 million and extended the maturity date to September 28, 2026. Borrowing options under this facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and Secured Overnight Financing Rate ("SOFR") loans. Borrowings against this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. There are no mandatory repayments prior to maturity under this facility. The facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(2) On September 28, 2022, the Company amended the facility to increase the borrowing capacity to $60 million. Borrowings under this facility are due on demand. Borrowing options under this facility include overdraft, letters of credit, Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and SOFR loans. Borrowings on this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. This facility is used to fund overdraft amounts and to issue letters of credit. As at December 31, 2022 a total of $5.6 million (December 31, 2021 - $3.2 million) in letters of credit were issued and are outstanding. This facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(3) PNG has $55 million of revolving credit facilities maturing on May 4, 2023, $30 million of which is with the Company and $25 million of which is with a Canadian chartered bank. The $25 million external facility is used to support PNG's capital spending program. Borrowings under the external facility are available by way of bankers' acceptances bearing interest at the three-month bankers' acceptance rate plus a spread and subject to stand-by fees. Interest and stand-by costs are due monthly. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. The facilities have covenants customary for these types of facilities, which must be met at each quarter end. PNG has been in compliance with all financial covenants each quarter since the establishment of these facilities.

(4) PNG has a $25 million operating credit facility with a Canadian chartered bank. The operating line is available for working capital purposes through cash draws in the form of prime-rate advances or bankers' acceptances and the issuance of letters of credit and is collateralized by a charge on PNG's accounts receivable and inventories. As at December 31, 2022, $5.1 million (December 31, 2021 - $5.1 million) of letters of credit were issued and outstanding under this facility.

In December 2022, TSU together with its wholly-owned subsidiary, TSU USA Holdings Inc., entered into a credit agreement establishing a US$150 million unsecured syndicated revolving credit facility (the "U.S. Credit Facility") which became available on closing of the Alaska Utilities Acquisition. Borrowing options under the U.S. Credit Facility include Canadian prime rate loans, U.S. base rate loans, bankers' acceptances, letters of credit and secured overnight financing rate loans with interest at rates relevant to the nature of the draw made and the applicable credit rating. The U.S. Credit Facility has a maturity date of March 1, 2026 and has financial covenants customary for these types of credit facilities, all of which are consistent with the Company's current $235 million unsecured syndicated revolving credit facility.

The following table summarizes the Company's primary financial covenants as defined by the credit facility agreements:

Ratios	Debt covenant Requirements [3]	As at December 31, 2022
Bank debt-to-capitalization[1][2]	not greater than 65 percent	**57.4%**

(1) Calculated in accordance with the Company's credit facility agreements, which are available on SEDAR at *www.sedar.com*.
(2) Estimated, subject to final adjustments.
(3) On July 16, 2021, the unsecured syndicated revolving credit facility was amended to only require the Consolidated EBITDA to Interest Expense covenant of not less than 2.5x to be reported if TSU's credit rating is below BBB (low) or equivalent.

Base Shelf Prospectus

On November 16, 2020, the Company filed a $1.0 billion base shelf prospectus. The purpose of the base shelf prospectus was to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remained effective. The base shelf prospectus dated November 16, 2020 expired on December 16, 2022. On January 4, 2023, the Company filed a $1.0 billion base shelf prospectus to replace the base shelf prospectus dated November 16, 2020.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issuer of securities.

On November 15, 2022, DBRS Morningstar ("DBRS") confirmed TSU's Issuer Rating and Unsecured Medium Term Notes rating of BBB(high) with a Stable trend.

Long-term obligations which are rated in the "BBB" category by DBRS are in the fourth highest category and are considered to be of adequate credit quality, with acceptable capacity for the payment of financial obligations. Entities in the "BBB" category may be considered to be vulnerable to future events, but the capacity for the payment of financial obligations is considered acceptable. DBRS uses "high" or "low" designations to indicate the relative standing of the securities being rated within a particular rating category.

The credit ratings assigned by DBRS are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There can be no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by DBRS at any time in the future, if, in its judgment, circumstances so warrant. The credit ratings on a security may not reflect the potential impact of all risks related to the value of the security.

TSU provides an annual fee to DBRS for credit rating services. TSU has paid DBRS its respective fees in connection with the provision of the above ratings. In addition to the aforementioned fees, TSU has made payments in respect of certain other services provided to the Company by DBRS.

CAPITAL EXPENDITURES

	Three Months Ended December 31, 2022				Three Months Ended December 31, 2021			
($ millions)	**Renewable Energy**	**Utilities**	**Corporate**	**Total**	Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	**$ —**	**$ 50.6**	**$ 0.2**	**$ 50.8**	$ —	$ 56.0	$ —	$ 56.0
Intangible assets	**—**	**1.0**	**—**	**1.0**	—	1.9	—	1.9
Capital expenditures	**—**	**51.6**	**0.2**	**51.8**	—	57.9	—	57.9
Disposals:								
PP&E	**—**	**(0.2)**	**—**	**(0.2)**	—	(0.3)	—	(0.3)
Net capital expenditures	**$ —**	**$ 51.4**	**$ 0.2**	**$ 51.6**	$ —	$ 57.6	$ —	$ 57.6

($ millions)	Year Ended December 31, 2022 Renewable Energy	Utilities	Corporate	Total	Year Ended December 31, 2021 Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	**$ —**	**$ 149.0**	**$ 0.3**	**$ 149.3**	$ —	$ 111.8	$ —	$ 111.8
Intangible assets	**—**	**2.4**	**—**	**2.4**	—	10.3	0.1	10.4
Capital expenditures	**—**	**151.4**	**0.3**	**151.7**	—	122.1	0.1	122.2
Disposals:								
PP&E	**—**	**(0.3)**	**—**	**(0.3)**	—	(0.5)	—	(0.5)
Net capital expenditures	**$ —**	**$ 151.1**	**$ 0.3**	**$ 151.4**	$ —	$ 121.6	$ 0.1	$ 121.7

Capital expenditures for the three and twelve months ended December 31, 2022 were $51.8 million and $151.7 million, respectively, compared to $57.9 million and $122.2 million, respectively for the three and twelve months ended December 31, 2021. The decrease in capital expenditures for the fourth quarter of 2022 compared to the same quarter in 2021 was mainly due to lower capital spending at PNG. The increase in capital expenditures for the year ended December 31, 2022 compared to the same period in 2021 was mainly due to higher capital spending at PNG, partially offset by lower software development costs.

CONTINGENCIES

The Company is subject to various legal claims and actions arising in the normal course of business. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Company does not believe that the resolution of such claims and actions will have a material impact on the Company's results of operations.

RISK MANAGEMENT

TSU is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. The Company enters into physical commodity contracts, foreign exchange and natural gas derivative contracts to manage exposure to fluctuations in commodity prices for its customers. Physical commodity contracts that meet the normal purchase and normal sale exemption are not recorded on the balance sheet at fair value and are recognized in the consolidated income statement when the contracts are settled. The board of directors provides oversight of the Company's risk management activities.

Risks Associated with Financial Instruments

The Company is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Interest Rate Risk

The Company is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Company manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. In addition, the Company's strategy is to optimize financing plans to maintain credit ratings to minimize interest costs. The Company proactively monitors and manages its debt maturity profile and debt covenants and maintains financial flexibility through access to multiple credit facilities.

On May 26, 2022, in connection with the Alaska Utilities Acquisition, the Company entered into a deal contingent forward starting interest rate swap in order to hedge a part of the interest rate exposure relating to future long-term debt financing.

This derivative has a notional value of US$100 million at a swap rate of 2.80 percent. As at December 31, 2022, the Company recorded a risk management contract asset of $8.4 million associated with the interest rate swap. During the three and twelve months ended December 31, 2022, the Company recognized an unrealized loss of $0.8 million and an unrealized gain of $8.4

million, respectively. The Company received approximately US$3.8 million on settlement of the interest rate swap on March 1, 2023.

Commodity Price Risk

The Company from time to time may enter into natural gas financial swaps to reduce the customers' exposure to natural gas price volatility. As at December 31, 2022, the Company had outstanding natural gas swaps with notional volumes of approximately 1.8 million MMBtu and risk management contract liability of $14.6 million that are expected to settle within one year. As at December 31, 2021, the Company had outstanding natural gas swaps with notional volumes of 495,000 MMBtu and risk management contract liability of $0.5 million. During the three and twelve months ended December 31, 2022, the Company recognized an unrealized loss of $16.3 million and $14.8 million, respectively (three and twelve months ended December 31, 2021 – unrealized loss of $0.5 million for both periods).

In addition, the Company has a biomethane purchase agreement which allows PNG to purchase renewable natural gas from a biogas production and purification facility up to a maximum of 230,000 GJ per annum for 15 years from the in-service date of the facility. Any unrealized gains and losses arising from changes in fair value of this agreement are deferred as a regulatory asset or liability. As at December 31, 2022, the Company recorded a risk management contract asset of $4.2 million (December 31, 2021 - $nil) associated with this contract.

Foreign Exchange Risk

The vast majority of EEI's natural gas supply costs are denominated in U.S. dollars. Although all natural gas procurement costs, including any realized foreign exchange gains or losses, are passed through to its customers, the Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in gas costs for customers as a result of changes in foreign exchange rates. In addition, the Company has entered into foreign exchange forward contracts to manage the foreign exchange risk from certain commitments denominated in U.S. dollars. As at December 31, 2022, the Company had outstanding foreign exchange forward contracts for US$31.8 million (December 31, 2021 – US$36.7 million) at an average rate of $1.33 Canadian per U.S. dollar (December 31, 2021 - $1.23 Canadian per U.S. dollar). These foreign exchange forward contracts have a duration of less than one year. As at December 31, 2022, the Company recorded a risk management contract asset of $0.6 million (December 31, 2021 - $1.2 million) associated with these contracts. During the three and twelve months ended December 31, 2022, the Company recognized an unrealized gain of $0.1 million and an unrealized loss of $0.5 million, respectively (three and twelve months ended December 31, 2021 – unrealized gain of $0.6 million and $2.6 million, respectively).

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract. The Company's maximum credit exposure consists primarily of the carrying value of accounts receivable and the fair value of derivative financial assets. The Company's utilities business generally has a large and diversified customer base, which minimizes the concentration of credit risk. To minimize credit risk, the utilities business will request a security deposit, which is eligible for refund after an observable period of compliance with payment terms. A credit report may also be requested. For the Company's Renewable Energy segment, all power generated is sold under the EPA with BC Hydro, an investment grade counterparty.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations as they come due and to support business operations and the Company's capital program. The Company's objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required. The Company's strategy is to maintain and comply with debt covenants to minimize financing costs. The Company's primary sources of liquidity and capital resources are cash generated from operations, borrowings under credit facilities, and long-term debt. The Company actively monitors current and future credit metrics including the impact of any forecasted planned capital expenditures in excess of cash from operations.

Risks Associated with TSU's Operations

The following table is a summary of the Company's principal risks related to its operations that could materially affect its business, results of operations, financial condition or cash flows. Further information on the Company's risk factors can be found in the

Annual Information Form. TSU manages its exposure to risks associated with operating its business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks
Regulatory and Stakeholder	
The Company is subject to uncertainties faced by regulated companies, such as the approval by the applicable regulators of rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. A failure to obtain rates that recover the costs of providing service or provide a reasonable opportunity to earn an expected ROE and capital structure as applied for may adversely affect the business carried on by the Company and may have a material adverse effect on the Company's results of operations and financial position. The acquisition, ownership and operation of energy infrastructure businesses and assets require numerous permits, approvals and certificates from federal, provincial, state and local government agencies and indigenous peoples. If there is a delay in obtaining any required regulatory approval or if the Company fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of natural gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Company's results of operations and financial position. The market for renewable power is heavily influenced by federal, provincial and local government regulations and policies in respect of tariffs, market structure and penalties. The Company's inability to predict, influence or respond appropriately to changes in law or regulatory frameworks could adversely impact the Company's results of operations.	• Skilled regulatory department retained • Regulatory personnel monitor new or changed laws or regulations • Proactive regulatory and stakeholder relations groups • Maintain trust of stakeholders and regulators through constructive and transparent relationships • Use of expert third parties when needed
Weather impact on the utilities	
Annual heating demand is highly seasonal, with the majority of demand occurring during the winter heating season. The applicable regulators set rates which assume normal weather conditions.	• Anticipated volumes are determined based on the 20-year rolling average for weather at AUI and EEI • PNG has a weather normalization account for residential and small commercial customers
Demand for natural gas	
Natural gas demand is impacted by a number of factors, including the weather, economic conditions, the number of customers, the customer mix, the availability, price, and environmental considerations related to natural gas and alternative forms of energy and energy efficiency measures taken by customers. The commodity cost of natural gas has traditionally been volatile. Carbon taxes impact the delivered price to customers. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk to levels of demand for natural gas, as other energy sources can become more cost-competitive.	• Regulatory mechanisms allow for recovery of cost of service • Rate structure and design helps reduce volatility of costs to customers • CRP in place at EEI to mitigate fuel switching • Stakeholder engagement • Investigate and implement where possible, alternative energy solutions for customers including supplying renewable natural gas
Volume of power generated	
Financial performance of the Company's renewable energy assets is dependent upon the availability of their input resources. The strength and consistency of the wind resource at the Bear Mountain Wind Park may impact the volume of power generated. A reduced amount of wind at the location of the Bear Mountain Wind Park over an extended period may reduce the production from the facility. This could also include shifts in weather or climate patterns, seasonal precipitation, and the timing and rate of snow pack melting and runoff which may impact the water flow to the Northwest Hydro Facilities and impact the volume of power generated.	• EPAs for the Bear Mountain Wind Park and Northwest Hydro Facilities are in place for all power generated to be purchased • Diversification of fuel source (wind and hydro) • Active management of maintenance schedule to ensure the facilities are available to produce when resource conditions are favourable

Risks	Strategies and Organizational Capability to Mitigate Risks
Operational	
The Company's distribution and renewable energy infrastructure is subject to physical risks such as fires, floods, explosions, leaks, sabotage, terrorism, natural disasters and equipment malfunction, many of which are beyond the control of the Company. Any of these hazards can interrupt operations, impact the Company's reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, and cause environmental damage that may include polluting water, land or air. Unplanned outages or prolonged downtime for maintenance and repair typically increase operation and maintenance expenses and reduce revenues.	• Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Ongoing infrastructure replacement programs within distribution system • Purchase property and business interruption insurance • Emergency response plan communicated and in place
Investment	
Through the normal course of the Company's operations, investments will be made in internal growth projects and, possibly, acquisition projects. The Company primarily invests in utilities infrastructure, which is supported by existing regulatory frameworks. None-the-less, growth projects carry inherent risk related to, but not limited to, cost, timing, regulatory approvals, credit worthiness of counterparties, and personnel resourcing.	• Investment in infrastructure projects is a core competency of each utility business, which is supported by standard operating practices, procurement practices, and formal project management programs • Proactive regulatory and stakeholder relations groups • If applicable, acquisition projects would be evaluated based on internal investment criteria and vetted through the Company's established governance framework
Environment and safety	
The ownership and operation of the Company's regulated utilities and renewable power assets carries an inherent risk of liability related to worker health and safety and the environment. Compliance with health, safety and environmental laws (and any future changes), the ability to meet environmental, social and governance ("ESG") targets, and the requirements of licences, permits and other approvals will remain material to the Company's businesses. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licences, requirements, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures.	• Strong safety and environmental management systems • Continuous process improvement strategy employed • Monitor evolving environmental regulations ensuring operations meet or exceed compliance standards • Zero tolerance safety policies for staff and contractors and reviews of past safety practices for contractors • Purchase and maintain general liability and business interruption insurance • Asset integrity programs are in place
Cybersecurity	
Security breaches of the Company's information technology infrastructure, including, without limitation, cyber-attacks, cyber-terrorism, malware/ransomware or other failures of the Company's information technology infrastructure could result in operational outages, delays, damage to assets, the environment or to the Company's reputation, diminished customer confidence, lost profits, lost data (including confidential information), increased regulation and other adverse outcomes, including, without limitation, material legal claims and liability or fines or penalties under applicable laws and adversely affect its business operations and financial results.	• Continuously updated perimeter and internal security • Ongoing cybersecurity awareness training to staff and corporate communications • Improvements based on third-party vulnerability and cybersecurity tests • Security-focused solution and system design • Corporate threat detection and incident response protocols • Cybersecurity insurance coverage
Labour relations	
The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain skilled workforces and the inability to do so could have a material adverse effect on the Company. The Company employs members of labour unions that have entered into collective bargaining agreements with the Company. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have a	• Maintain access to strong labour markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions • Maintain succession plans for key positions • Maintain competitive compensation programs

Risks	Strategies and Organizational Capability to Mitigate Risks
material adverse effect on the Company's results of operations and financial position.	
Litigation	
In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company.	• Proactive management of lawsuits and other claims • Continuous monitoring of defense and settlement costs of lawsuits and claims • Use of expert third parties when needed • Strong in-house legal department

RELATED PARTY TRANSACTIONS

In the normal course of business, the Company transacts with its joint ventures and associates.

The following transactions with TSU's joint ventures and associates are measured at the exchange amount and have been recorded on the consolidated statements of income in the Consolidated Financial Statements:

	Year ended December 31 2022	2021
Revenue(1)	**$ 1.3**	$ 0.9
Operating and administrative expenses(2)	**$ (0.1)**	$ (0.1)

(1) In the normal course of business, the Company provided gas sales and transportation services to related parties.

(2) Operating and administrative expenses include the administrative costs recovered from joint venture.

In February 2023, TriSummit Cycle Inc. contributed approximately of $631.1 million (US$471 million) of equity to fund a portion of the Alaska Utilities Acquisition. No additional shares were issued as a result of the equity contribution.

SHARE INFORMATION

	As at March 8, 2023
Issued and outstanding	
Common Shares	30,000,000

ADOPTION OF NEW ACCOUNTING STANDARDS

The Company did not adopt any new Accounting Standards Updates ("ASU") issued by FASB during year ended December 31, 2022.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. The adoption of ASU 2016-13 is not expected to have a material impact on the financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has guaranteed payment for certain commitments on behalf of its subsidiaries as further described below. The primary obligations guaranteed by the Company have been included in the Company's balance sheet and commitments note in the Consolidated Financial Statements.

In October 2014, EEI entered into a throughput service contract with Enbridge Inc. for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (the "Atlantic Bridge Project"). The contract commenced on October 1, 2020 and will expire 15 years thereafter. The Company issued two guarantees with an aggregate maximum liability of US$91.7 million, guaranteeing EEI's payment obligations under the throughput service contract with Enbridge Inc.

The Company, through EEI, has other agreements in place with natural gas distributors, wholesale gas marketers and financial institutions for the purchase and transportation of natural gas and by-products thereof including forward or other financial settled contracts. As at December 31, 2022, the Company had guarantees with an aggregate maximum of US$70.0 million and $3.3 million guaranteeing EEI's payment under those agreements.

On October 22, 2018, the Company issued a guarantee with a maximum liability of $0.3 million related to the land tenure and the right of way for permanent access and power line access at Bear Mountain Wind Park.

DISCLOSURE CONTROLS AND PROCEDURES ("DC&P") AND INTERNAL CONTROL OVER FINANCIAL REPORTING ("ICFR")

The Company is a "Venture Issuer" under applicable Canadian securities regulations for certain purposes. As such, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are not required to certify the design and evaluation of the Company's DC&P and ICFR under National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*. However, the CEO and CFO have reviewed the Consolidated Financial Statements and this MD&A. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Company as at the date of and for the periods presented.

SELECTED ANNUAL FINANCIAL INFORMATION

		Year Ended December 31	
($ millions, except where noted)	**2022**	2021	2020
Revenue	**465.3**	377.1	322.8
Net income after taxes	**36.6**	51.2	22.8
Net income after taxes per Common Share - Basic and Diluted ($ per Common Share)	**1.22**	1.71	0.76
Total assets	**1,917.4**	1,748.7	1,649.7
Total long-term financial liabilities(1)	**799.6**	776.4	722.4
Weighted average number of Common Shares outstanding (millions)	**30.0**	30.0	30.0
Dividends declared per Common Share ($ per share)	**1.1875**	1.1175	1.0550

(1) Excludes deferred financing costs.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures used by the Company that do not have a standardized meaning prescribed by U.S. GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with U.S. GAAP. The non-GAAP measures and their reconciliation to U.S. GAAP financial measures are shown below. These non-GAAP measures provide additional information that management believes is meaningful in describing the Company's operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to normalized EBITDA, normalized net income (loss), normalized net income (loss) per share, normalized funds from operations, normalized funds from operations per share, net debt and net debt to total capitalization throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

($ millions)	Three Months Ended December 31 **2022**	2021	Year Ended December 31 **2022**	2021
Normalized EBITDA	**$ 43.4**	$ 39.7	**$ 127.1**	$ 123.8
Add (deduct):				
Foreign exchange loss	**—**	(0.1)	**—**	(0.3)
Unrealized gain (loss) on risk management contracts	**(17.0)**	0.1	**(6.9)**	2.2
Accretion expense	**(0.1)**	(0.1)	**(0.2)**	(0.3)
Depreciation and amortization expense	**(11.1)**	(10.1)	**(44.7)**	(40.2)
Accretion and depreciation and amortization expense from equity investment(1)	**(1.4)**	(0.8)	**(4.0)**	(3.5)
Transaction costs	**(2.6)**	—	**(5.3)**	—
Operating income	**$ 11.2**	$ 28.7	**$ 66.0**	$ 81.7

(1) Inclusive of TSU's proportionate share of unrealized loss of $0.5 million on remeasurement of the Northwest Transmission Line liability in relation to the equity investment in the Northwest Hydro Facilities for the three and twelve months ended December 31, 2022.

Normalized EBITDA is a measure of the Company's operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using operating income adjusted for depreciation and amortization expense, accretion expense, foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, and other typically non-recurring items such as the transaction costs associated with the acquisition of the Alaska Utilities Business. Normalized EBITDA is frequently used by investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets and the capital structure.

Normalized EBITDA as presented should not be viewed as an alternative to operating income or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Net Income and Normalized Net Income per Share

($ millions)	Three Months Ended December 31 **2022**	2021	Year Ended December 31 **2022**	2021
Normalized net income	**$ 23.6**	$ 20.9	**$ 50.5**	$ 49.0
Add (deduct) after-tax:				
Unrealized gain (loss) on risk management contracts	**(19.1)**	0.1	**(9.0)**	2.2
Proportionate share of unrealized loss on remeasurement of the Northwest Transmission Line liability in relation to the equity investment in the Northwest Hydro Facilities	**(0.5)**	—	**(0.5)**	—
Transaction costs	**(2.1)**	—	**(4.4)**	—
Net income after taxes	**$ 1.9**	$ 21.0	**$ 36.6**	$ 51.2

Normalized net income represents net income after taxes adjusted for the after tax impact of unrealized gain on risk management contracts and other typically non-recurring items, such as the transaction costs associated with the acquisition of the Alaska Utilities Business. Normalized net income per share is calculated by dividing normalized net income by the weighted average number of common shares. This measure is presented in order to enhance the comparability of results, as it reflects the underlying performance of the Company.

Normalized net income and normalized net income per share as presented should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Funds from Operations and Normalized Funds from Operations per Share

($ millions)	Three Months Ended December 31 2022	2021	Year Ended December 31 2022	2021
Normalized funds from operations	**$ 37.4**	$ 36.9	**$ 97.0**	$ 92.3
Add (deduct):				
Changes in operating assets and liabilities	**(8.2)**	(16.2)	**12.5**	3.1
Transaction costs	**(2.6)**	—	**(5.3)**	—
Cash from operations	**$ 26.6**	$ 20.7	**$ 104.2**	$ 95.4

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Company without regard to changes in operating assets and liabilities in the period as well as other non-operating related income and expenses, such as the transaction costs associated with the acquisition of the Alaska Utilities Business. Management uses this measure to understand the ability to generate funds for use in investing and financing activities.

Normalized funds from operations per share is calculated by dividing normalized funds from operations by the weighted average number of common shares.

Normalized funds from operations and normalized funds from operations per share as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with U.S. GAAP as an indicator of liquidity.

Net Debt and Net Debt to Total Capitalization

Net debt and net debt to total capitalization are used by the Company to monitor its capital structure and financing requirements. It is also used as a measure of the Company's overall financial strength. Net debt is defined as short-term debt, plus current and long-term portions of long-term debt, less cash and cash equivalents. Total capitalization is defined as net debt plus shareholders' equity. Additional information regarding these non-GAAP measures can be found under the *"Liquidity and Capital Resources – Capital Resources"* section of this MD&A.

DEFINITIONS

AUC	Alberta Utilities Commission
BCUC	British Columbia Utilities Commission
CPI	Consumer Price Index
GCOC	Generic Cost of Capital
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
MMBtu	metric million British thermal unit
MTN	Medium-term note
MW	megawatt
PJ	Petajoule; one million gigajoules
PP&E	Property, plant and equipment

ABOUT TSU

TSU is a North American company with natural gas distribution, transmission and storage utilities and renewable power generation assets. TSU serves approximately 284,000 customers across Canada and the United States, delivering lower carbon energy, safely and reliably. For more information visit: www.trisummit.ca

Independent Auditor's Report

To the Shareholders of TriSummit Utilities Inc.

Opinion

We have audited the consolidated financial statements of TriSummit Utilities Inc. and its subsidiaries (the Group), which comprise the consolidated balance sheets as at December 31, 2022 and 2021, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at December 31, 2022 and 2021, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles (US GAAP).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises information included in the:

- Management's Discussion and Analysis

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Group's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

The engagement partner on the audit resulting in this independent auditor's report is Robert Mitchell.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Alberta
March 8, 2023

Consolidated Balance Sheets

As at *($ millions)*	**December 31, 2022**	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	**$ 5.1**	$ 5.9
Accounts receivable, net of allowances *(notes 15 and 17)*	**112.1**	90.4
Inventory *(note 5)*	**4.9**	3.0
Regulatory assets *(note 8)*	**5.4**	5.2
Risk management contract assets *(note 17)*	**9.0**	1.2
Prepaid expenses and other current assets	**6.5**	4.6
	143.0	110.3
Property, plant and equipment *(note 6)*	**1,211.8**	1,099.6
Intangible assets *(note 7)*	**37.9**	41.1
Goodwill	**119.1**	119.1
Regulatory assets *(note 8)*	**254.5**	252.4
Risk management contract assets *(note 17)*	**4.2**	—
Other long-term assets *(notes 9 and 19)*	**34.7**	12.7
Investments accounted for by the equity method *(note 10)*	**112.2**	113.5
	$ 1,917.4	$ 1,748.7
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 17)*	**$ 118.8**	$ 88.2
Short-term debt *(notes 11 and 17)*	**41.5**	—
Current portion of long-term debt *(notes 12 and 17)*	**25.9**	1.0
Customer deposits	**10.9**	10.5
Regulatory liabilities *(note 8)*	**14.9**	7.3
Risk management contract liabilities *(note 17)*	**15.2**	0.5
Other current liabilities *(note 9)*	**2.9**	2.3
	230.1	109.8
Long-term debt *(notes 9, 12 and 17)*	**796.5**	773.4
Asset retirement obligations *(note 13)*	**5.5**	4.8
Deferred income taxes *(note 16)*	**169.2**	156.1
Regulatory liabilities *(note 8)*	**62.4**	47.4
Lease liabilities *(note 9)*	**11.3**	6.2
Future employee obligations *(note 19)*	**10.7**	22.7
	$ 1,285.7	$ 1,120.4

Shareholder's equity				
Common shares, no par value, unlimited shares authorized; December 31, 2022 and December 31, 2021 - 30 million shares issued and outstanding *(note 18)*		**321.0**		321.0
Contributed surplus		**100.0**		100.0
Retained earnings		**210.0**		209.0
Accumulated other comprehensive income (loss) *(notes 14 and 19)*		**0.7**		(1.7)
		631.7		628.3
	$	**1,917.4**	$	1,748.7

Commitments, contingencies and guarantees *(note 20)*
Subsequent events *(note 24)*

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of TriSummit Utilities Inc.

(signed) “David W. Cornhill”

DAVID W. CORNHILL
Director

(signed) “Wendy Henkelman”

WENDY HENKELMAN
Director

Consolidated Statements of Income

($ millions)		Year ended December 31 2022		2021
REVENUE *(notes 15 and 21)*	**$**	**465.3**	$	377.1
EXPENSES				
Cost of sales, exclusive of items shown separately		**230.4**		154.8
Operating and administrative *(notes 9, 19 and 21)*		**125.4**		108.8
Accretion *(note 13)*		**0.2**		0.3
Depreciation and amortization *(notes 6 and 7)*		**44.7**		40.2
		400.7		304.1
Income from equity investments *(note 10)*		**5.8**		6.3
Unrealized (loss) gain on risk management contracts *(note 17)*		**(6.9)**		2.2
Other income *(note 19)*		**2.5**		0.5
Foreign exchange loss		**—**		(0.3)
Operating income		**66.0**		81.7
Interest expense				
Short-term debt		**(1.0)**		(0.3)
Long-term debt		**(30.8)**		(27.8)
Income before income taxes		**34.2**		53.6
Income tax recovery (expense) *(note 16)*				
Current		**1.7**		(2.3)
Deferred		**0.7**		(0.1)
Net income after taxes	**$**	**36.6**	$	51.2

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Comprehensive Income

($ millions)		Year ended December 31 2022		2021
Net income after taxes	**$**	**36.6**	$	51.2
Other comprehensive income (OCI), net of taxes				
Actuarial gain on pension and post-retirement benefit plans *(notes 14 and 19)*		**2.3**		0.8
Reclassification to net income of actuarial gains and losses on pension and post-retirement benefit plans *(notes 14 and 19)*		**0.1**		0.2
Other comprehensive income, net of taxes		**2.4**		1.0
Comprehensive income, net of taxes	**$**	**39.0**	$	52.2

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Equity

($ millions)		2022		Year ended December 31 2021
Common shares *(note 18)*				
Balance, beginning of year	**$**	**321.0**	$	321.0
Balance, end of year	**$**	**321.0**	$	321.0
Contributed surplus				
Balance, beginning of year	**$**	**100.0**	$	100.0
Balance, end of year	**$**	**100.0**	$	100.0
Retained earnings				
Balance, beginning of year	**$**	**209.0**	$	191.3
Net income after taxes		**36.6**		51.2
Common share dividends		**(35.6)**		(33.5)
Balance, end of year	**$**	**210.0**	$	209.0
Accumulated other comprehensive income (loss) *(note 14)*				
Balance, beginning of year	**$**	**(1.7)**	$	(2.7)
Other comprehensive income		**2.4**		1.0
Balance, end of year	**$**	**0.7**	$	(1.7)
Total shareholder's equity	**$**	**631.7**	$	628.3

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

($ millions)		2022		Year ended December 31 2021
Cash from operations				
Net income after taxes	**$**	**36.6**	$	51.2
Items not involving cash:				
Depreciation and amortization expense *(notes 6 and 7)*		**44.7**		40.2
Accretion expense *(note 13)*		**0.2**		0.3
Deferred income tax expense (recovery) *(note 16)*		**(0.7)**		0.1
Income from equity investments *(note 10)*		**(5.8)**		(6.3)
Unrealized loss (gain) on risk management contracts *(note 17)*		**6.9**		(2.2)
Other		**1.2**		—
Distributions from equity investments *(note 10)*		**8.6**		9.0
Changes in operating assets and liabilities *(note 22)*		**12.5**		3.1
	$	**104.2**	$	95.4
Investing activities				
Additions to property, plant and equipment		**(152.8)**		(101.8)
Additions to intangible assets		**(3.7)**		(11.0)
Proceeds from disposition of assets, net of transaction costs		**0.3**		0.5
Contributions to equity investments		**(1.5)**		(0.1)
	$	**(157.7)**	$	(112.4)
Financing activities				
Net issuance (repayment) of short-term debt		**41.5**		(4.1)
Net (repayment) issuance of bankers' acceptances		**(51.0)**		54.9
Issuance of long-term debt note, net of debt issuance costs		**98.8**		—
Repayment of long-term debt		**(1.0)**		(1.0)
Common share dividends		**(35.6)**		(33.5)
Other		**—**		(0.5)
	$	**52.7**	$	15.8
Change in cash and cash equivalents		**(0.8)**		(1.2)
Cash and cash equivalents, beginning of year		**5.9**		7.1
Cash and cash equivalents, end of year	**$**	**5.1**	$	5.9

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars, unless otherwise indicated.)

1. OVERVIEW OF THE COMPANY

TriSummit Utilities Inc. (“TSU” or the “Company”) is incorporated under the Canada Business Corporations Act and its registered office and principal place of business is in Calgary, Alberta. TSU is a wholly owned subsidiary of TriSummit Cycle Inc., a company in which the Public Sector Pension Investment Board indirectly holds a majority economic interest and Alberta Investment Management Corporation holds a minority economic interest.

The Company owns and operates rate-regulated distribution and transmission utility businesses through its wholly owned subsidiaries Apex Utilities Inc. (“AUI”) in Alberta, Pacific Northern Gas Ltd. (“PNG”) and Pacific Northern Gas (N.E.) Ltd. (“PNG(N.E.)”) in British Columbia and Eastward Energy Incorporated (formerly Heritage Gas Limited) (“EEI”) in Nova Scotia. The Company also owns the Bear Mountain Wind Park, an approximately 10 percent indirect interest in the Northwest Hydro Facilities, and a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. Upon the closing of the Alaska Utilities Acquisition on March 1, 2023 (see note 4), the Company’s utility businesses also include wholly-owned operating subsidiaries ENSTAR Natural Gas Company, LLC and the Alaska Pipeline Company, LLC, as well as a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC.

2. BASIS OF PRESENTATION

Basis of Preparation

These consolidated financial statements (“Financial Statements”) have been prepared by management in accordance with United States Generally Accepted Accounting Principles (“U.S. GAAP”).

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (“NI 52-107”), U.S. GAAP reporting is permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that the Company is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, the Company sought and obtained exemptive relief from the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on the earlier of (a) January 1, 2027; (b) the date upon which the Company ceases to have activities subject to rate regulation, and (c) the first day of the Company’s financial year that commences on or following the later of (i) the effective date prescribed by the international Accounting Standards Board (“IASB”) for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation and (ii) two years after the IASB publishes the final version of a mandatory rate regulated standard.

In January 2021, IASB published the exposure draft *Regulatory Assets and Liabilities*, which would be applicable to entities with rate regulated activities. The effective date for mandatory application of the eventual final standard, if any, is not yet determinable and the Company continues to monitor the developments of the exposure draft and determine the potential impacts to the Company’s financial statements.

Principles of Consolidation

The Financial Statements include the accounts of the Company and its direct and indirect subsidiaries, including, without limitation: Alaska Utility Holdings Inc. (“AUHI”), TSU USA Holdings Inc. (“TSUH”), TriSummit Utility Group Inc., Bear Mountain Wind Limited Partnership, TriSummit Canadian Energy Holdings Ltd., PNG, AUI, and EEI. The Financial Statements also include investments in Northwest Hydro Limited Partnership (“Coast LP”), Inuvik Gas Ltd., and NGIF Cleantech Ventures Limited Partnership (“NGIF”), which are accounted for by the equity method. Intercompany transactions and balances are eliminated. Investments in unconsolidated companies that the Company has significant influence over, but not control, are accounted for using the equity method. In addition, the Company uses the equity method of accounting for investments in limited partnership interests in which it has more than a minor interest or influence over the partnership's operating and financial policies.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition

Renewable Energy segment

The majority of the revenues are earned through a power purchase agreement whereby the Company is the lessor in the operating lease arrangement. Variable lease payments are recorded as revenue in the period in which the changes in facts and circumstances on which the variable lease payments are based on occur, such as when actual electricity is generated and delivered.

Utilities segment

Customers are billed monthly based on regular meter readings. Customer billings are based on two components: (i) a fixed service fee; and (ii) a variable fee based on usage. Revenue is recognized over time when the gas has been delivered or as the service has been performed. As meter readings occur on a cycle basis, the Company recognizes accrued revenue for any services rendered to its customers but not billed at month-end. Although the majority of these contracts have a term of one-month, certain contracts have terms of one year or longer. For these long-term contracts, there is generally a contract demand specified in the contract whereby the customer has to pay regardless of whether or not gas has been delivered. These contracts generally do not contain any make up rights and revenue is recognized monthly as service is performed.

Rate-Regulated Operations

AUI, PNG and EEI, (collectively "the Utilities") engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission ("AUC"), the British Columbia Utilities Commission ("BCUC"), and the Nova Scotia Utility and Review Board ("NSUARB"), respectively.

The AUC, BCUC, and NSUARB exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC, BCUC, and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate setting process. See note 8 for a description of the principal financial statements effects of rate regulation.

Cash and cash equivalents

Cash and cash equivalents include cash on deposit with banks and interest-bearing short term investments with a maturity of three months or less when purchased. Cash and cash equivalents are stated at cost, which approximates market value.

Accounts Receivable

Receivables are recorded net of the credit losses in the Consolidated Balance Sheet. The Company regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, and natural gas, which are valued at the lower of cost or net realizable value. Cost of inventory is determined using a weighted average cost formula.

Property, Plant, and Equipment ("PP&E") and Depreciation
PP&E are carried at cost. The Company depreciates the cost of PP&E, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of rate regulated utilities assets, where depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

Interest costs are capitalized on major additions to PP&E until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on the prior quarter actual borrowing long-term interest rate.

Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction ("AFUDC"). AFUDC is the amount that a rate regulated enterprise is allowed to recover for its cost of financing assets under construction. Capitalized overhead, administrative expenses and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers through depreciation expense, as allowed by the regulators.

Certain additions to PP&E are made with the assistance of contributions in aid of construction, which are offset against the corresponding asset balances and amortized at the same rate as the corresponding asset.

The range of useful lives for the Company's PP&E is as follows:

Renewable Energy assets	5 – 30 years
Utilities assets	3 – 75 years
Corporate assets	2 – 3 years

As required by the respective regulatory authorities, net additions to utility assets at EEI and PNG are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI are depreciated commencing in the year in which the assets are brought into active service.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in the Consolidated Statement of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statement of Income.

Leases - Lessee
An arrangement contains a lease when such arrangement conveys the right to control the use of an identified asset. TSU recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which consists of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, less any lease incentives received and any initial direct costs incurred by the lessee. The lease liability is initially measured at the present value of the lease payments that are not yet paid at the commencement date, discounted using the interest rate implicit in the lease or if that cannot be readily determined, TSU's incremental borrowing rate. Lease payments include: fixed payments (including in substance fixed payments), variable lease payments that are based on an index or a rate, the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, payments for penalties for terminating the lease if the lease term reflects the lessee exercising that option, and amounts probable of being payable by the lessee under residual value guarantees. The Company has elected the practical expedient to not separate lease and non-lease components for its office and equipment leases. Subsequent measurement of the right-of-use asset and lease liability depend on whether the lease is classified as an operating lease or financing lease. Lease payments for leases with a term of twelve months or less are expensed on a straight-line basis over the lease term.

Intangible Assets

Intangible assets which have a finite life are recorded at cost and are amortized on a straight-line basis over their term or estimated useful life. The range of useful lives for intangible assets with a finite life is as follows:

Software	3 - 10 years
Land rights	5 - 75 years
Franchises and consents	9 - 25 years

Business Combinations

Business combinations are accounted for using the acquisition method. Under the acquisition method, assets and liabilities of the acquired entity are recorded at fair value at the date of acquisition. Goodwill represents the excess of purchase price over the fair value of the net assets acquired. Associated transaction costs are expensed as incurred.

Impairment of Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value and an impairment loss is recognized.

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Company has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the fair value of each reporting unit is compared to its carrying value. The fair value of each reporting unit is determined using either the income approach or the market approach. If the carrying value of the reporting unit exceeds the fair value, an impairment loss would be recorded in the Consolidated Statement of Income.

Development Costs

The Company expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria continue to be met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period of benefit, beginning at the commencement of commercial operations.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which the Company has the ability to exercise significant influence, but does not have a controlling interest. In addition, the Company uses the equity method of accounting for investments in limited partnership interests in which it has more than a minor interest or influence over the partnership's operating and financial policies. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Company will capitalize interest costs associated with its investment during such period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statement of Income.

Financial Instruments

Financial instruments are initially recorded at fair value unless they qualify for, and are designated under a normal purchase and normal sale ("NPNS") exemption. Subsequent measurement of the financial instruments is based on their classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Company's business needs and the Company has the ability, and intent, to deliver or take delivery of the underlying item. The Company continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading financial assets and liabilities consist of risk management contracts used to manage fluctuations in foreign exchange, commodity prices and interest rates. These financial instruments are not designated as hedges and are initially recorded at their fair value, with subsequent changes in fair value recorded in net income under "unrealized gain and loss from risk management contracts". Held-to-maturity, loans and receivables, and other financial liabilities are recognized at amortized cost using the effective interest method.

PNG's contracts to purchase biomethane are regulated by the BCUC. As a result, any unrealized gains and losses arising from changes in fair value are deferred as a regulatory asset or liability.

Gains and losses on hedging instruments used to hedge foreign currency exposure of a net investment in a foreign operation are recognized in OCI.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in earnings.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheet. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in "Interest expense" on the Consolidated Statement of Income.

Asset Retirement Obligations

The Company recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

Certain utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to their indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations.

Foreign Currency Translation

These consolidated financial statements are presented in Canadian dollars. Monetary assets and liabilities denominated in a foreign currency are converted to the functional currency (Canadian dollars) using the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statement of Income. Non-monetary assets and liabilities are converted at the historical exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the period-end exchange rates while revenues and expenses are translated at the exchange rates applicable at the time of the transaction.

Pension Plans and Post-Retirement Benefits

The Company maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Company to the defined contribution plans are expensed in the period in which the contribution occurs. The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Pension expense for the defined benefit and post-retirement benefit plans includes the cost of pension benefits earned during the year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments, the amortization of prior service costs, and the amortization of cumulative unrecognized net actuarial gains and losses in excess of 10 percent of the greater of the accrued benefit obligation or the fair value of plan assets. Amortizations are calculated on a straight-line basis over the expected average remaining service life of active employees. The expected average remaining service period of the active members covered by the defined benefit pension plans and the post-retirement benefit plans is 15.0 years and 14.8 years, respectively.

The Company recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheet. Unrecognized actuarial gains and losses and past service costs and credits that arise during the period are recognized in OCI.

For certain regulated Utilities, the Company expects to recover pension expense in future rates and therefore records actuarial gains and losses as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees or the benefit period for employees, or a specific recovery period as approved by the respective regulator.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized.

The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Investment tax credits, if any, are deferred and amortized over the estimated service lives of the related assets.

Interest and penalties assessed by taxing authorities on any underpayment of income tax are accrued and classified as a component of interest expense in the Consolidated Statement of Income.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from, or paid to, customers in the future.

Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Any such accruals are adjusted thereafter as additional information becomes available or circumstances change.

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of these Financial Statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: revenue recognition, credit loss estimates, depreciation and amortization rates, determination of the classification, term and incremental borrowing rate for leases, fair value of asset retirement obligations, fair value of property, plant and equipment and goodwill for impairment assessments, fair value of financial instruments, provisions for income taxes, assumptions used to measure employee future benefits, provisions for contingencies, and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which the Company operates, which often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued Accounting Standards Update ("ASU") No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. The adoption of ASU 2016-13 is not expected to have a material impact on the Financial Statements.

4. ACQUISITION OF THE ALASKA UTILITIES BUSINESS

On March 1, 2023, AUHI, a subsidiary of the Company, completed the acquisition of a 100 percent interest in ENSTAR Natural Gas Company, LLC, the Alaska Pipeline Company, and the Norstar Pipeline Company, Inc. (collectively, "ENSTAR"), and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") from a subsidiary of AltaGas Ltd., in an all cash transaction valued at approximately US$800 million, before customary post-closing adjustments (the "Alaska Utilities Acquisition"). As at February 28, 2023, CINGSA had approximately US$45 million (approximately US$29 million proportionate share) of outstanding senior notes which remain in place. Due to the timing of the acquisition, the initial accounting for the Alaska Utilities Acquisition has not been finalized.

The Alaska Utilities Acquisition was financed using: (i) US$471 million of equity; (ii) net proceeds from the private placement offering of senior unsecured notes in three series totaling US$165 million (see note 12); (iii) partial net proceeds of US$100 million ($135 million) from the medium-term notes ("MTNs") issued in January 2023 (see note 12); and (iv) borrowings from the Company's credit facilities.

ENSTAR is the largest gas utility in the State of Alaska, servicing approximately 60 percent of the State's population, with approximately 150,000 customers and 3,626 miles of transmission and distribution pipeline. CINGSA, located in Kenai, Alaska, is the only commercial, fully contracted, state regulated gas storage facility in Alaska.

5. INVENTORY

As at	December 31, 2022	December 31, 2021
Natural gas	$ 3.6	$ 2.2
Other inventory	1.3	0.8
	$ 4.9	$ 3.0

6. PROPERTY, PLANT AND EQUIPMENT

As at	December 31, 2022			December 31, 2021		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Renewable Energy	$ 212.8	$ (93.0)	$ 119.8	$ 212.7	$ (85.7)	$ 127.0
Utilities	1,305.2	(213.5)	1,091.7	1,159.8	(187.3)	972.5
Corporate	0.6	(0.3)	0.3	0.3	(0.2)	0.1
	$ 1,518.6	$ (306.8)	$ 1,211.8	$ 1,372.8	$ (273.2)	$ 1,099.6

During the year ended December 31, 2022, the Company capitalized AFUDC (debt and equity component) of $0.9 million (2021 - $1.4 million).

Contributions in aid of construction of $5.1 million (2021 - $2.1 million) were recorded as a reduction of cost during the year.

Depreciation expense related to property, plant and equipment for the year ended December 31, 2022 was $35.5 million (2021 - $33.0 million). As at December 31, 2022, the Company had approximately $18.1 million (December 31, 2021 - $16.0 million) of capital projects under construction that were not yet subject to amortization. In addition, as at December 31, 2022, $2.7 million of land costs (December 31, 2021 - $2.6 million) were not subject to amortization.

7. INTANGIBLE ASSETS

As at	December 31, 2022			December 31, 2021		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Software	$ 42.8	$ (12.5)	$ 30.3	$ 44.7	$ (11.5)	$ 33.2
Land rights	9.8	(3.0)	6.8	9.8	(2.8)	7.0
Franchises and consents	3.6	(2.8)	0.8	3.6	(2.7)	0.9
	$ 56.2	$ (18.3)	$ 37.9	$ 58.1	$ (17.0)	$ 41.1

Amortization expense related to intangible assets for the year ended December 31, 2022 was $5.7 million (2021 - $4.8 million).

As at December 31, 2022, the Company excluded $2.2 million (December 31, 2021 - $2.2 million) of assets with an indefinite life from the asset base subject to amortization.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization as well as assets with indefinite life, for the years ended December 31:

2023	$	5.6
2024	$	4.8
2025	$	4.1
2026	$	4.1
2027	$	4.1
Thereafter	$	13.0

8. REGULATORY ASSETS AND LIABILITIES

The Company accounts for certain transactions in accordance with ASC 980, Regulated Operations. The Company refers to this accounting guidance for regulated entities as “regulatory accounting”. Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheet when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statement of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statement of Income in future periods when the amounts are reflected in customer rates. Management’s assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the AUC, BCUC and NSUARB.

If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting for all or part of its utility operations, regulatory assets and liabilities related to those portions ceasing to meet the criteria would be de-recognized from the Consolidated Balance Sheet and included in the Consolidated Statement of Income for the period in which discontinuance of regulatory accounting occurs. Factors that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the Company’s ability to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Company’s review of these criteria currently supports continued application of regulatory accounting for the Utilities.

The table below summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets as at December 31, 2022 and 2021 and the remaining period over which the Company expects to realize the assets or settle the liabilities:

As at		**December 31, 2022**		December 31, 2021	Recovery Period
Regulatory assets - current					
Deferred cost of gas	**$**	**4.4**	$	4.0	Less than one year
Deferred property taxes		**1.0**		1.0	Less than one year
Other		**—**		0.2	Less than one year
	$	**5.4**	$	5.2	
Regulatory assets - non-current					
Deferred regulatory costs and rate stabilization adjustment	**$**	**3.8**	$	3.5	Various
Future recovery of pension and other retirement benefits [a]		**0.8**		17.2	Various
Deferred depreciation and amortization [b]		**20.2**		20.8	Various
Deferred future income taxes [c]		**151.0**		137.8	Various
Deferred customer retention program amortization [d]		**48.1**		44.3	Various
Revenue deficiency account [e]		**24.6**		23.6	Various
Other		**6.0**		5.2	Various
	$	**254.5**	$	252.4	
Regulatory liabilities - current					
Deferred cost of gas	**$**	**13.6**	$	5.7	Less than one year
Other		**1.3**		1.6	Less than one year
	$	**14.9**	$	7.3	
Regulatory liabilities - non-current					
Option fees deferral [f]	**$**	**2.1**	$	2.5	Various
Rate stabilization adjustment mechanism		**2.4**		4.3	Various
Future removal and site restoration costs [g]		**36.7**		31.2	Various
Large volume industrial deferral account [h]		**6.8**		5.8	Various
Pension and other retirement benefits [a]		**9.2**		—	Various
Other		**5.2**		3.6	Various
	$	**62.4**	$	47.4	

(a) Certain utilities have recovered pension costs related to regulated operations in rates, and as such the Company has recorded a regulatory asset for pension funding deficiency and a regulatory liability for pension funding surplus. Depending on the method utilized by the utility the recovery period can be either the expected service life of the employees, or the benefit period for employees, or a specific recovery period as approved by the respective regulator.

(b) Pursuant to the NSUARB decisions in 2009 and 2011, EEI was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the fiscal periods from 2009 to 2013. The NSUARB, in its decision dated November 24, 2011, directed amortization to be phased in over a four year period at the following rates: 2014 at 25 percent of the authorized rates; 2015 at 50 percent of the authorized rates; 2016 at 75 percent of the authorized rates; and 2017 at 100 percent of the authorized rates. As a result of this order, EEI recognized a regulatory asset equal to the amortization that would have otherwise been included in rates.

(c) Remaining amortization period varies depending on the timing of underlying transactions.

(d) In 2016, the NSUARB approved EEI's Customer Retention Program ("CRP") application to decrease distribution rates for commercial customers with consumption between 500 and 4,999 gigajoule per year, suspend depreciation and to increase the capitalization rate for operating, maintenance and administrative expenses. On April 21, 2020, the NSUARB approved EEI's application to revise the CPR deferral mechanism to defer amounts equivalent to the price discount provided to certain small commercial customers, rather than suspending depreciation and deferring a portion of operating, maintenance and administrative expenses.

(e) EEI has an approval from the NSUARB to use a revenue deficiency account ("RDA") until it is fully recovered, subject to a maximum of $50 million, which may be increased subject to approval by the NSUARB. The RDA is the cumulative difference between the revenue requirements and the actual amounts billed to customers.

(f) Pursuant to BCUC approved negotiated settlement agreement.

(g) This amount and timing of draw down is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.

(h) Deferral account was approved by the BCUC as part of the PNG reactivation project application to capture certain revenues, interest and termination fees received from current and formerly contracted shippers. As the large volume industrial deferral account is a mechanism intended to provide rate stability, PNG will seek BCUC approval for proposed funding and amortization of the deferral account in future revenue requirements applications.

9. LEASES

The Company's leases include: land, buildings, and office and field equipment.

As at	December 31, 2022	December 31, 2021
Weighted average remaining lease term (years)		
Operating leases	**20.4**	23.7
Finance leases	**9.0**	12.9
Weighted average discount rate (%)		
Operating leases	**4.6**	3.5
Finance leases	**2.6**	2.9

As at		December 31, 2022		December 31, 2021
Operating Leases				
Operating lease right of use assets[(a)]	**$**	**12.5**	$	7.0
Current[(b)]	**$**	**1.4**	$	1.1
Long-term		**11.3**		6.2
Total operating lease liabilities	**$**	**12.7**	$	7.3
Finance Leases				
Finance lease right of use assets, net[(c)]	**$**	**0.4**	$	0.4
Long-term debt		**0.4**		0.4
Total finance lease liabilities	**$**	**0.4**	$	0.4

(a) Included under the line item "Other long-term assets" on the Consolidated Balance Sheets.
(b) Included under the line item "Other current liabilities" on the Consolidated Balance Sheets.
(c) Included under the line item "Property, plant and equipment" on the Consolidated Balance Sheets.

Maturity analysis of lease liabilities during the next five years and thereafter is as follows:

As at December 31, 2022		Operating Leases		Finance Leases
2023	**$**	1.6	**$**	—
2024		1.6		—
2025		1.3		—
2026		1.4		—
2027		1.4		—
Thereafter		12.8		0.5
Total lease payments	**$**	20.1	**$**	0.5
Less: imputed interest		(7.4)		(0.1)
Total	**$**	12.7	**$**	0.4

The following table summarizes the lease expense recognized in the Consolidated Statement of Income:

				Year ended December 31
		2022		2021
Operating lease cost				
Operating leases	**$**	**1.6**	$	1.7
Short-term leases		**0.2**		0.2
Variable lease payments not included in the determination of lease liabilities		**0.5**		0.5
Total operating lease cost[(a)]	**$**	**2.3**	$	2.4
Finance lease cost				
Amortization of right-of-use assets		**0.1**		—
Total finance lease cost		**0.1**		—
Total lease cost	**$**	**2.4**	$	2.4

(a) Included under the line item "Operating and administrative" on the Consolidated Statements of Income.

The following table provides supplemental information related to leases:

				Year ended December 31
		2022		2021
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows used for operating leases	**$**	**1.6**	$	1.7
Right of use assets obtained in exchange for new lease liabilities:				
Operating leases	**$**	**6.6**	$	1.1

10. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Description	**Location**	**Ownership Percentage**		**December 31, 2022**		December 31, 2021
Inuvik Gas Ltd.	Canada	33.33	**$**	**0.3**	$	0.2
Coast LP	Canada	10		**110.6**		113.3
NGIF	Canada	9		**1.3**		—
			$	**112.2**	$	113.5

Summarized financial information, assuming a 100% ownership interest in the equity investments listed above, is as follows:

				Year ended December 31
		2022		2021
Revenues	**$**	**150.1**	$	146.3
Expenses		**(91.0)**		(84.0)
	$	**59.1**	$	62.3

As at		**December 31, 2022**		December 31, 2021
Current assets	**$**	**19.8**	$	20.5
Property, plant and equipment	**$**	**996.9**	$	1,019.3
Intangible assets	**$**	**234.8**	$	237.6
Current liabilities	**$**	**(30.7)**	$	(27.1)
Other long-term liabilities	**$**	**(114.8)**	$	(117.3)

During the year ended December 31, 2022, a distribution of $8.6 million was received from Coast LP (2021 - $9.0 million).

11. SHORT-TERM DEBT

As at December 31, 2022, the Company held a $60.0 million (December 31, 2021 - $35.0 million) revolving operating credit facility with a Canadian chartered bank. Borrowings under this facility are due on demand. Draws on this facility are by way of overdraft, Canadian prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and Secured Overnight Financing Rate ("SOFR") loans. As at December 31, 2022, outstanding borrowings under this facility were $39.0 million (December 31, 2021 - $ nil). Letters of credit outstanding under this facility as at December 31, 2022 were $5.6 million (December 31, 2021 - $3.2 million).

As at December 31, 2022, the Company held a $25.0 million (December 31, 2021 - $25.0 million) bank operating facility which is available for PNG's working capital purposes. Draws on this facility are by way of prime-rate advances, bankers' acceptances or letters of credit at the bank's prime rate or for a fee. As at December 31, 2022, prime-rate advances under the operating facility were $2.5 million (December 31, 2021 - $nil). Letters of credit outstanding under this facility as at December 31, 2022 were $5.1 million (December 31, 2021 - $5.1 million).

12. LONG-TERM DEBT

As at	Maturity date		**December 31, 2022**		December 31, 2021
Credit facilities					
$235 million unsecured revolving credit facility(a)	28-Sep-2026	**$**	**28.2**	$	79.0
$25 million PNG committed credit facility(b)	4-May-2023		**25.0**		25.0
Debenture notes					
PNG 2025 series debenture - 9.30 percent(c)	18-Jul-2025		**10.5**		11.0
PNG 2027 series debenture - 6.90 percent(c)	2-Dec-2027		**11.5**		12.0
Medium term notes					
$300 million senior unsecured - 4.26 percent	5-Dec-2028		**300.0**		300.0
$250 million senior unsecured - 3.15 percent	6-Apr-2026		**250.0**		250.0
$100 million senior unsecured - 3.13 percent	7-Apr-2027		**100.0**		100.0
$100 million senior unsecured - 5.28 percent	15-Aug-2052		**100.0**		—
Finance lease liabilities *(note 9)*			**0.4**		0.4
		$	**825.6**	$	777.4
Less debt issuance costs and discount			**(3.2)**		(3.0)
		$	**822.4**	$	774.4
Less current portion			**(25.9)**		(1.0)
		$	**796.5**	$	773.4

(a) Borrowings on the credit facility can be by way of Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and SOFR loans. On September 28, 2022, the Company amended the facility to increase the borrowing capacity to $235 million and extended the maturity date to September 28, 2026.

(b) Borrowings on the credit facility can be by way of Canadian prime rate-based loans and bankers' acceptances.

(c) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of PNG's PP&E and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

On January 11, 2023, TSU completed the issuance of $200 million medium-term notes with a coupon rate of 5.02 percent (5.026 percent yield to maturity) and a maturity date of January 11, 2030.

On March 1, 2023, AUHI completed a private placement offering of senior unsecured notes in three series totaling US$165 million: (i) series A senior unsecured notes in the aggregate principal amount of US$50 million that carry a coupon rate of 5.34 percent and mature on December 15, 2027; (ii) series B senior unsecured notes in the aggregate principal amount of US$25 million that carry a coupon rate of 5.38 percent and mature on March 31, 2030; and (iii) series C senior unsecured notes in the aggregate principal amount of US$90 million that carry a coupon rate of 5.41 percent and mature on March 31, 2033 (collectively, the "AUHI Notes").

In December 2022, TSU together with its wholly owned subsidiary, TSUH entered into a credit agreement establishing a US$150 million unsecured syndicated revolving credit facility (the "U.S. Credit Facility") which became available on closing of the Alaska Utilities Acquisition. The U.S. Credit Facility has a maturity date of March 1, 2026, and has financial covenants customary for these types of credit facilities.

Principal repayments of long-term debt during the next five years and thereafter are as follows:

As at		
2023	$	26.0
2024	$	1.0
2025	$	10.0
2026	$	278.8
2027	$	109.5
2028	$	300.1
Thereafter	$	100.2
	$	825.6

13. ASSET RETIREMENT OBLIGATIONS

As at		**December 31, 2022**		December 31, 2021
Balance, beginning of year	**$**	**4.8**	$	4.5
Revision in estimated cash flow		**0.5**		—
Accretion expense		**0.2**		0.3
Balance, end of year	**$**	**5.5**	$	4.8

The Company estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2022 was $10.7 million (December 31, 2021 - $9.7 million).

Asset retirement obligations have been recorded in the consolidated financial statements at estimated values discounted at rates between 3.4 and 7.5 percent and are expected to be incurred between 2028 and 2044. No assets have been legally restricted for settlement of the estimated liability.

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

		Defined benefit pension and post-retirement benefits plans
Opening balance, January 1, 2022	$	**(1.7)**
OCI before reclassification		**3.1**
Amounts reclassified from AOCI		**0.1**
Current period OCI (pre-tax)		**3.2**
Income tax on amounts retained in AOCI		**(0.8)**
Net current period OCI		**2.4**
Ending balance, December 31, 2022		**0.7**
Opening balance, January 1, 2021	$	(2.7)
OCI before reclassification		1.1
Amounts reclassified from OCI		0.2
Current period OCI (pre-tax)		1.3
Income tax on amounts retained in AOCI		(0.3)
Net current period OCI		1.0
Ending balance, December 31, 2021		(1.7)

15. REVENUE

The following table disaggregates revenue by major sources:

	Year ended December 31, 2022			
	Renewable Energy	**Utilities**	**Corporate**	**Total**
Revenue from contracts with customers				
Gas sales and transportation services	**$ —**	**$ 440.2**	**$ —**	**$ 440.2**
Other	**0.8**	**4.2**	**—**	**5.0**
Total revenue from contracts with customers	**$ 0.8**	**$ 444.4**	**$ —**	**$ 445.2**
Other sources of revenue				
Revenue from alternative revenue programs	**$ —**	**$ 2.4**	**$ —**	**$ 2.4**
Leasing revenue[(a)]	**17.1**	**—**	**—**	**17.1**
Other	**—**	**0.6**	**—**	**0.6**
Total revenue from other sources	**$ 17.1**	**$ 3.0**	**$ —**	**$ 20.1**
Total revenue	**$ 17.9**	**$ 447.4**	**$ —**	**$ 465.3**

(a) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

	Year ended December 31, 2021			
	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 351.9	$ —	$ 351.9
Other	1.5	2.6	—	4.1
Total revenue from contracts with customers	$ 1.5	$ 354.5	$ —	$ 356.0
Other sources of revenue				
Leasing revenue[(a)]	18.4	—	—	18.4
Other	—	2.7	—	2.7
Total revenue from other sources	$ 18.4	$ 2.7	$ —	$ 21.1
Total revenue	$ 19.9	$ 357.2	$ —	$ 377.1

(a) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

The carrying value of PP&E associated with leasing revenue was $118.3 million as at December 31, 2022 (December 31, 2021 - $125.5 million).

Accounts receivable as at December 31, 2022 include unbilled receivables of $54.0 million (December 31, 2021 - $48.8 million) related to gas sales and transportation services rendered to customers but not billed at period end.

Transaction price allocated to the remaining obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied as at December 31, 2022:

	2023	2024	2025	2026	2027	> 2028	Total
Gas sales and transportation services	$ 22.3	$ 19.0	$ 19.8	$ 19.4	$ 19.2	$ 300.0	**$ 399.7**

The Company applies the practical expedient available under ASC 606 and does not disclose information about the remaining performance obligations for (i) contracts with an original expected length of one year or less, (ii) contracts for which revenue is recognized at the amount to which the Company has the right to invoice for performance completed, and (iii) contracts with variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation. In addition, the table above does not include any estimated amounts of variable consideration that are constrained. The majority of gas sales and transportation service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as gas is delivered or as service is provided.

16. INCOME TAXES

	Year ended December 31 2022	2021
Income before income taxes	**$ 34.2**	$ 53.6
Statutory income tax rate (%)	**25.1**	25.2
Expected taxes at statutory rates	**$ 8.6**	$ 13.5
Add (deduct) the tax effect of:		
Permanent differences between accounting and tax basis of assets and liabilities	**0.5**	0.1
Change in valuation allowance	**(1.1)**	(1.1)
Effect of differences in rates of subsidiaries	**(0.4)**	0.4
Other	**(1.8)**	—
Deferred income tax recovery on regulated assets	**(8.2)**	(10.5)
Income tax expense (recovery)	**$ (2.4)**	$ 2.4
Current	**$ (1.7)**	$ 2.3
Deferred	**(0.7)**	0.1
	$ (2.4)	$ 2.4
Effective income tax rate (%)	**(7.0)**	4.5

Net deferred income tax liabilities comprise of the following:

As at	**December 31, 2022**	December 31, 2021
PP&E and intangible assets	**$ 114.8**	$ 98.7
Investments	**14.8**	15.3
Regulatory assets	**44.2**	47.0
Risk Management assets	**2.1**	—
Deferred compensation	**1.7**	(4.0)
Non-capital losses	**(25.5)**	(17.5)
Tax pools	**—**	(0.8)
Valuation allowance	**14.9**	16.1
Other	**2.2**	1.3
	$ 169.2	$ 156.1

The amount shown on the Consolidated Balance Sheets as deferred income tax liabilities represents the net differences between the tax basis and book carrying values on the Company's balance sheets at enacted tax rates.

As at December 31, 2022, the Company had non-capital losses of approximately $79.9 million (December 31, 2021 - $58.4 million), which expire between 2028 and 2042.

As at December 31, 2022 and 2021, the Company had no provision for uncertain tax positions.

17. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, risk management contract assets (liabilities), accounts payable and accrued liabilities, short-term debt, current portion of long-term debt, and long-term debt. In addition, the Company entered into physical commodity contracts to manage exposure to fluctuations in commodity prices for its customers. Physical commodity contracts that meet the normal purchase and normal sale exemption are not recorded on the balance sheet at fair value and are recognized in the consolidated income statement when the contracts are settled.

Fair Value Hierarchy

The Company categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used.

Level 2 - fair values are determined based on valuation models and techniques where inputs other than quoted prices included within level 1 are observable for the asset or liability either directly or indirectly. The Company uses derivative instruments to manage fluctuations in foreign exchange rates, natural gas prices and interest rates. The Company estimates forward prices based on observable market prices and rates from published sources.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. The Company uses valuation techniques when observable market data is not available. The Company's level 3 derivatives include renewable energy physical purchase contracts with no observable market data. The Company uses comparable benchmark information and risk adjusted discount rates as inputs to estimate fair value for these derivatives.

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and short-term debt - the carrying amounts approximate fair value because of the short maturity of these instruments.

					December 31, 2022
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Fair value through net income					
Risk management contract assets - current					
Foreign exchange contracts	**$ 0.6**	**$ —**	**$ 0.6**	**$ —**	**$ 0.6**
Interest rate swap	**8.4**	**—**	**8.4**	**—**	**8.4**
Fair value through regulatory assets and liabilities					
Risk management contracts assets - non-current					
Commodity contracts	**4.2**	**—**	**—**	**4.2**	**4.2**
	$ 13.2	**$ —**	**$ 9.0**	**$ 4.2**	**$ 13.2**
Financial liabilities					
Fair value through net income					
Risk management contract liabilities - current					
Commodity contracts	**$ 15.2**	**$ —**	**$ 15.2**	**$ —**	**$ 15.2**
Amortized cost					
Current portion of long-term debt[(a)]	**26.0**	**—**	**26.0**	**—**	**26.0**
Long-term debt[(a)]	**799.6**	**—**	**758.9**	**—**	**758.9**
	$ 840.8	**$ —**	**$ 800.1**	**$ —**	**$ 800.1**

(a) Excludes deferred financing costs and debt discount.

					December 31, 2021
	Carrying	Level 1	Level 2	Level 3	Total
Financial assets					
Fair value through net income					
Risk management contract assets - current					
Foreign exchange contracts	$ 1.2	$ —	$ 1.2	$ —	$ 1.2
	$ 1.2	$ —	$ 1.2	$ —	$ 1.2
Financial liabilities					
Fair value through net income					
Risk management contract liabilities - current					
Commodity contracts	$ 0.5	$ —	$ 0.5	$ —	$ 0.5
Amortized cost					
Short-term debt					
Current portion of long-term debt[(a)]	1.0	—	1.0	—	1.0
Long-term debt[(a)]	776.4	—	830.6	—	830.6
	$ 777.9	$ —	$ 832.1	$ —	$ 832.1

(a) Excludes deferred financing costs and debt discount.

The following table presents the significant unobservable inputs used in the fair value measurement of Level 3 financial instruments:

December 31, 2022	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Weighted average price**	**Unit of Measurement**
Commodity contract - physical					
Renewable natural gas	$ 4.2	Discounted cash flow	Renewable natural gas price	$ 32.76	$/GJ

There is uncertainty caused by using unobservable inputs and changes in the unobservable inputs could result in significantly different fair values.

The following table presents the changes in fair value of risk management contract assets and liabilities classified as Level 3 of the fair value hierarchy:

As at		**December 31, 2022**		December 31, 2021
Balance, beginning of period	**$**	**—**	$	—
Unrealized gain included in regulatory liabilities		**4.2**		—
Balance, end of period	**$**	**4.2**	$	—

There were no transfers into or out of Level 3 as at December 31, 2022 or December 31, 2021.

Risks associated with financial instruments

The Company is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Interest Rate Risk

The Company is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Company manages interest rate risk by holding a mix of both fixed and floating interest rate debt. In addition, the Company's strategy is to optimize financing plans to maintain credit ratings to minimize interest costs. The Company proactively monitors and manages its debt maturity profile and debt covenants and maintains financial flexibility through access to multiple credit facilities.

On May 26, 2022, in connection with the Alaska Utilities Acquisition, the Company entered into a deal contingent forward starting interest rate swap in order to hedge a part of the interest rate exposure relating to future long-term debt financing. This derivative has a notional value of US$100 million at a swap rate of 2.80 percent. During the year ended December 31, 2022, the Company recognized an unrealized gain of $8.4 million. The Company received approximately US$3.8 million on settlement of the interest rate swap on March 1, 2023.

Commodity Price Risk

The Company from time to time may enter into natural gas financial swaps to reduce the customers' exposure to natural gas price volatility. As at December 31, 2022, the Company had outstanding natural gas swaps with notional volumes of approximately 1.8 million MMBtu that are expected to settle within one year. As at December 31, 2021, the Company had outstanding natural gas swaps with notional volumes of 495,000 MMBtu. During the year ended December 31, 2022, the Company recognized an unrealized loss of $14.8 million (2021 – unrealized loss of $0.5 million).

In addition, the Company has a biomethane purchase agreement which allows PNG to purchase renewable natural gas from a biogas production and purification facility up to a maximum of 230,000 GJ per annum for 15 years from the in-service date of the facility. Any unrealized gains and losses arising from changes in fair value of this agreement are deferred as a regulatory asset or liability.

Foreign Exchange Risk

The vast majority of EEI's natural gas supply costs are denominated in U.S. dollars. Although all natural gas procurement costs, including any realized foreign exchange gains or losses are passed through to its customers, the Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in gas costs for customers as a result of changes in foreign exchange rates. As at December 31, 2022, the Company had outstanding foreign exchange forward contracts for US$31.8 million at an average rate of $1.33 Canadian per U.S. dollar. These foreign exchange forward contracts have a duration of less than one year. As at December 31, 2021, the Company had outstanding foreign exchange forward contracts for US$36.7 million at an average rate of $1.23 Canadian per U.S. dollar. During the year ended December 31, 2022, the Company recognized an unrealized loss of $0.5 million (2021 – $2.6 million).

In February 2023, TSU entered into a foreign exchange swap contract to sell US$100 million for 1.3386 Canadian per U.S. dollar in order to hedge the foreign currency exposure related to the Alaska utilities business.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract. The Company's maximum credit exposure consists primarily of the carrying value of accounts receivable and the fair value of derivative financial assets. The Company's utilities business generally has a large and diversified customer base, which minimizes the concentration of credit risk. To minimize credit risk, the utilities business will request for a security deposit which is eligible for refund after an observable period of compliance with payment terms. A credit report may also be requested. For the Company's renewable generation assets, all power generated are sold under the electricity purchase agreement with BC Hydro, an investment grade counterparty.

Accounts Receivable Past Due or Impaired

The Company had the following past due or impaired accounts receivable (AR):

As at December 31, 2022		**Total**		**AR accruals**		**Receivables impaired**		**Less than 30 days**		**31 to 60 days**		**61 to 90 days**		**Over 90 days**
Trade receivable	**$**	**103.9**	**$**	**54.0**		**1.7**		**44.9**		**1.8**		**0.4**		**1.1**
Other		**9.9**		**—**		**—**		**9.9**		**—**		**—**		**—**
Allowance for credit losses		**(1.7)**		**—**		**(1.7)**		**—**		**—**		**—**		**—**
	$	**112.1**	**$**	**54.0**	**$**	**—**	**$**	**54.8**	**$**	**1.8**	**$**	**0.4**	**$**	**1.1**

As at December 31, 2021		Total		AR accruals		Receivables impaired		Less than 30 days		31 to 60 days		61 to 90 days		Over 90 days
Trade receivable	$	88.9	$	48.8	0	1.3	0	35.0	0	1.8	0	0.5	0	1.5
Other		2.8		0.5	0	—	0	2.3	0	—	0	—	0	—
Allowance for credit losses		(1.3)		—	0	(1.3)	0	—	0	—	0	—	0	—
	$	90.4	$	49.3	$	—	$	37.3	$	1.8	$	0.5	$	1.5

Allowance for credit losses		Year ended December 31 **2022**		2021
Balance, beginning of year	**$**	**1.3**	$	1.5
New allowance		**0.7**		0.5
Recovery of allowance		**0.7**		0.4
Allowance applied to uncollectible customer accounts		**(1.0)**		(1.1)
Balance, end of year	**$**	**1.7**	$	1.3

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations as they come due and to support business operations and the Company's capital program. The Company's objective is to ensure it has access to debt and equity funding as required. The Company's strategy is to maintain and comply with debt covenants to minimize financing costs.

The Company had the following contractual maturities with respect to financial liabilities:

				Payments due by period	
As at December 31, 2022	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 118.8**	**$ 118.8**	**$ —**	**$ —**	**$ —**
Short-term debt	**41.5**	**41.5**	**—**	**—**	**—**
Current portion of long-term debt [(a)]	**26.0**	**26.0**	**—**	**—**	**—**
Long-term debt [(a)]	**799.6**	**—**	**11.0**	**388.3**	**400.3**
	$ 985.9	**$ 186.3**	**$ 11.0**	**$ 388.3**	**$ 400.3**

(a) Excludes deferred financing costs and debt discount.

				Payments due by period	
As at December 31, 2021	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 88.2	$ 88.2	$ —	$ —	$ —
Short-term debt	—	—	—	—	—
Current portion of long-term debt [(a)]	1.0	1.0	—	—	—
Long-term debt [(a)]	776.4	—	27.0	339.5	409.9
	$ 865.6	$ 89.2	$ 27.0	$ 339.5	$ 409.9

(a) Excludes deferred financing costs and debt discount.

18. SHAREHOLDER'S EQUITY

Authorized share capital

The Company is authorized to issue an unlimited number of voting common shares. The Company is also authorized to issue preferred shares not to exceed 50 percent share of the voting rights attached to the issued and outstanding common shares.

Common shares issued and outstanding

As at December 31, 2022 and 2021, there were 30,000,000 of common shares issued and outstanding.

Contributed surplus

In February 2023, TriSummit Cycle Inc. contributed approximately $631.1 million (US$471 million) of equity to fund a portion of the Alaska Utilities Acquisition. No additional shares were issued as a result of the equity contribution.

19. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

The Company has a defined contribution ("DC") pension plan for substantially all employees who are not members of defined benefit plans. The pension cost recorded for the DC plan was $0.6 million for the year ended December 31, 2022 (2021 - $0.5 million).

Defined Benefit Plans and Post-Retirement Benefits

The Company has several defined benefit plans and post-retirement benefit plans for unionized and non-unionized employees. All defined benefit plans are funded. The post-retirement benefit plans are not funded except for one plan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

Supplemental Executive Retirement Plan ("SERP")

The Company has non-registered, defined benefit pension plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Company as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Actuarial valuation

The Company's most recent actuarial valuation of its defined benefit plans for funding purposes was completed as at December 31, 2021. The Company is required to file an actuarial valuation of its Canadian defined benefit plans with the pension regulators at least every three years. The actuarial valuation for funding purposes was filed with the pension regulators in 2022 and the next actuarial valuation for funding purposes is required to be completed as of a date no later than December 31, 2024. The following table summarizes details of the Company's defined benefit plans, including the SERP and post-retirement plans:

Year ended December 31, 2022	**Defined Benefit**	**Post-Retirement Benefits**	**Total**
Accrued benefit obligation			
Balance, beginning of year	**$ 149.3**	**$ 14.7**	**$ 164.0**
Actuarial gain	**(42.5)**	**(4.5)**	**(47.0)**
Current service cost	**7.9**	**0.8**	**8.7**
Member contributions	**0.1**	**—**	**0.1**
Interest cost	**4.3**	**0.4**	**4.7**
Benefits paid	**(5.9)**	**(0.3)**	**(6.2)**
Expenses paid	**(0.3)**	**—**	**(0.3)**
Balance, end of year	**$ 112.9**	**$ 11.1**	**$ 124.0**
Plan assets			
Fair value, beginning of year	**$ 134.8**	**$ 11.0**	**$ 145.8**
Actual return on plan assets	**(11.1)**	**(0.6)**	**(11.7)**
Employer contributions	**6.4**	**0.3**	**6.7**
Member contributions	**0.1**	**—**	**0.1**
Benefits paid	**(5.9)**	**(0.3)**	**(6.2)**
Expenses paid	**(0.3)**	**—**	**(0.3)**
Fair value, end of year	**$ 124.0**	**$ 10.4**	**$ 134.4**
Net amount recognized	**$ 11.1**	**$ (0.7)**	**$ 10.4**

Year ended December 31, 2021		Defined Benefit		Post-Retirement Benefits		Total
Accrued benefit obligation						
Balance, beginning of year	$	157.9	$	15.3	$	173.2
Actuarial gain		(15.3)		(1.6)		(16.9)
Current service cost		8.9		0.9		9.8
Member contributions		0.1		—		0.1
Interest cost		3.5		0.4		3.9
Benefits paid		(5.5)		(0.3)		(5.8)
Expenses paid		(0.3)		—		(0.3)
Balance, end of year	$	149.3	$	14.7	$	164.0
Plan assets						
Fair value, beginning of year	$	118.2	$	10.4	$	128.6
Actual return on plan assets		14.8		0.6		15.4
Employer contributions		7.5		0.3		7.8
Member contributions		0.1		—		0.1
Benefits paid		(5.5)		(0.3)		(5.8)
Expenses paid		(0.3)		—		(0.3)
Fair value, end of year	$	134.8	$	11.0	$	145.8
Net amount recognized	$	(14.5)	$	(3.7)	$	(18.2)

As at December 31, 2022, the most significant factor contributing to actuarial gains on the defined benefit plans and the post-retirement benefit plans was the increase in the discount rate used to determine the present value of obligations.

The following amounts were included in the Consolidated Balance Sheet:

		December 31, 2022						December 31, 2021				
		Defined Benefit		**Post-Retirement Benefits**		**Total**		Defined Benefit		Post-Retirement Benefits		Total
Other long-term assets	**$**	**15.7**	**$**	**5.4**	**$**	**21.1**	$	—	$	4.5	$	4.5
Future employee obligations		**(4.6)**		**(6.1)**		**(10.7)**		(14.5)		(8.2)		(22.7)
	$	**11.1**	**$**	**(0.7)**	**$**	**10.4**	$	(14.5)	$	(3.7)	$	(18.2)

The funded status based on the accumulated benefit obligation for all defined benefit plans were:

As at		**December 31, 2022**		December 31, 2021
Accumulated benefit obligation [(a)]	**$**	**(100.8)**	$	(130.4)
Fair value of plan assets		**124.0**		134.8
Funded status	**$**	**23.2**	$	4.4

(a) Accumulated benefit obligation differs from future employee obligations accrued on the balance sheet in that it does not include an assumption with respect to future compensation levels.

The following amounts were not recognized in the net periodic benefit cost and recorded in other comprehensive losses:

Year ended December 31, 2022		**Defined Benefit**		**Post-Retirement Benefits**		**Total**
Net actuarial gain	**$**	**0.2**	**$**	**0.7**	**$**	**0.9**
Recognized in AOCI pre-tax	**$**	**0.2**	**$**	**0.7**	**$**	**0.9**
Income tax expense		**(0.1)**		**(0.1)**		**(0.2)**
Net amount in AOCI after-tax	**$**	**0.1**	**$**	**0.6**	**$**	**0.7**

Year ended December 31, 2021	Defined Benefit	Post-Retirement Benefits	Total
Net actuarial loss	$ (0.2)	$ (2.1)	$ (2.3)
Recognized in AOCI pre-tax	$ (0.2)	$ (2.1)	$ (2.3)
Income tax recovery	0.1	0.5	0.6
Net amount in AOCI after-tax	$ (0.1)	$ (1.6)	$ (1.7)

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

The net pension expense by plan for the period was as follows:

Year ended December 31, 2022	**Defined Benefit**	**Post-Retirement Benefits**	**Total**
Current service cost[a]	**$ 7.9**	**$ 0.8**	**$ 8.7**
Interest cost[b]	**4.3**	**0.4**	**4.7**
Expected return on plan assets[b]	**(7.3)**	**(0.3)**	**(7.6)**
Amortization of net actuarial loss [b]	**—**	**0.1**	**0.1**
Amortization of regulatory assets and liabilities[b]	**0.8**	**(0.2)**	**0.6**
Net benefit cost recognized	**$ 5.7**	**$ 0.8**	**$ 6.5**

(a) Recorded under the line item "Operating and administrative" expenses on the Consolidated Statement of Income
(b) Recorded under the line item "Other income" on the Consolidated Statement of Income.

Year ended December 31, 2021	Defined Benefit	Post-Retirement Benefits	Total
Current service cost[a]	$ 8.9	$ 0.9	$ 9.8
Interest cost[b]	3.5	0.4	3.9
Expected return on plan assets[b]	(6.2)	(0.3)	(6.5)
Amortization of net actuarial loss [b]	—	0.2	0.2
Amortization of regulatory asset and liabilities[b]	2.3	(0.2)	2.1
Net benefit cost recognized	$ 8.5	$ 1.0	$ 9.5

(a) Recorded under the line item "Operating and administrative" expenses on the Consolidated Statement of Income.
(b) Recorded under the line item "Other income" on the Consolidated Statement of Income.

The objective of the Company's investment policy is to maximize long-term total return while protecting the capital value of the fund from major market fluctuations through diversification and selection of investments.

The objective for fund returns, over three to five-year periods, is the sum of two components – a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management. It is the Company's belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three-to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each fund manager's mandate. There is also the risk of annual volatility in returns, which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the fund manager(s) within the constraints prescribed by their mandate(s).

The Company has a target asset mix of 45 percent to 55 percent fixed income assets. These objectives take into account the nature of the liabilities and the risk-reward tolerance of the Company.

The collective investment mixes for the plans are as follows as at December 31, 2022:

	Fair value	Level 1	Level 2	Level 3	Percentage of Plan Assets (%)
Cash and cash equivalents	$ **6.6**	$ 6.6	$ —	$ —	4.9
Canadian equities	**36.8**	36.8	—	—	27.4
Foreign equities	**37.1**	37.1	—	—	27.6
Fixed income	**45.6**	45.6	—	—	33.9
Real estate	**8.3**	—	8.3	—	6.2
	$ **134.4**	$ 126.1	$ 8.3	$ —	100.0

Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Year ended December 31	**2022**		2021	
Discount rate (%)	**1.80 - 3.34**	**3.26 - 3.33**	1.00 - 2.81	2.69 - 2.79
Expected long-term rate of return on plan assets (%) [(a)]	**0.00 - 5.62**	**3.05**	0.00 - 5.29	2.90
Rate of compensation increase (%)	**2.50 - 3.00**	**3.00**	2.00 - 3.00	3.00
Average remaining service life of active employees (years)	**15.0**	**14.8**	15.1	14.8

(a) Only applicable for funded plans

Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
As at December 31	**2022**		2021	
Discount rate (%)	**5.05 - 5.27**	**5.27**	1.80 - 3.34	3.26 - 3.33
Rate of compensation increase (%)	**2.50 - 3.50**	**3.00**	2.00 - 3.00	3.00

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 5.9% percent and the ultimate trend rate is 4.0% percent, which is expected to be achieved by 2040.

The following table shows the expected cash flows for defined benefit pension and other-post retirement plans:

		Defined Benefit		Post-Retirement Benefits
Expected employer contributions:				
2023	$	6.4	$	0.4
Expected benefit payments:				
2023	$	5.1	$	0.4
2024		5.4		0.4
2025		5.6		0.4
2026		5.8		0.5
2027		5.9		0.5
2028-2032	$	33.2	$	3.0

20. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

The Company has long-term natural gas purchase and transportation arrangements, service agreements and operating and finance leases, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments at December 31, 2022 are estimated as follows:

		2023		2024		2025		2026		2027		2027 and beyond		**Total**
Gas purchase and transportation [a]	$	60.0	$	30.1	$	28.7	$	25.1	$	22.6	$	186.5	**$**	**353.0**
Service agreement [b]		3.7		3.7		3.8		3.9		1.5		6.4		**23.0**
Operating and finance leases [c]		1.6		1.6		1.3		1.4		1.4		13.3		**20.6**
	$	65.3	$	35.4	$	33.8	$	30.4	$	25.5	$	206.2	**$**	**396.6**

(a) The Company enters into contracts to purchase natural gas, renewable natural gas, and natural gas transportation services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2022 to 2040, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

(b) In 2021, the Company extended and amended the existing service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain Wind Park. The Company has an obligation to pay approximately $11.9 million from 2023 to 2026. In 2019, the Company entered into a long-term agreement for software implementation, hosting and maintenance. The Company is obligated to pay approximately US$11.0 million over the 10-year term of the contract.

(c) Operating and finance leases include lease arrangements for office spaces, land, and office and other equipment.

Guarantees

The Company has guaranteed payment for certain commitments on behalf of its subsidiaries as further described below. The primary obligations guaranteed by the Company have been included in the Company's balance sheet and commitments note.

In October 2014, EEI entered into a throughput service contract with Enbridge Inc. for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (the "Atlantic Bridge Project"). The contract commenced on October 1, 2020 and will expire 15 years thereafter. The Company issued two guarantees with an aggregate maximum liability of US$91.7 million, guaranteeing EEI's payment obligations under the throughput service contract with Enbridge Inc.

The Company, through EEI, has other agreements in place with natural gas distributors, wholesale gas marketers and financial institutions for the purchase and transportation of natural gas and by-products thereof including forward or other financial settled contracts. As at December 31, 2022, the Company had guarantees with an aggregate maximum of US$70.0 million and $3.3 million guaranteeing EEI's payment under those agreements.

On October 22, 2018, the Company issued a guarantee with a maximum liability of $0.3 million related to the land tenure and the right of way for permanent access and power line access at Bear Mountain Wind Park.

Contingencies

The Company is subject to various legal claims and actions arising in the normal course of the Company. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Company does not believe that the resolution of such claims and actions will have a material impact on the Company's consolidated financial position or results of operations.

21. RELATED PARTY TRANSACTIONS

In the normal course of business, the Company transacts with its joint ventures and associates.

Related party transactions

The following transactions with joint ventures and associates are measured at the exchange amount and have been recorded on the Consolidated Statements of Income.

				Year ended December 31
		2022		2021
Revenue[(a)]	**$**	**1.3**	$	0.9
Operating and administrative expenses[(b)]	**$**	**(0.1)**	$	(0.1)

(a) In the normal course of business, the Company provided gas sales and transportation services to related parties.

(b) Operating and administrative expenses include the administrative costs recovered from joint venture.

22. SUPPLEMENTAL CASH FLOW INFORMATION

The following table details the changes in operating assets and liabilities:

				Year ended December 31
		2022		2021
Source (use) of cash:				
Accounts receivable	**$**	**(19.7)**	$	(26.3)
Inventory		**(1.8)**		(0.9)
Other current assets		**(1.9)**		—
Regulatory assets (current)		**(0.1)**		(1.4)
Accounts payable and accrued liabilities		**32.2**		18.7
Customer deposits		**0.4**		0.1
Regulatory liabilities (current)		**7.3**		1.1
Other current liabilities		**0.3**		0.1
Net change in regulatory assets and liabilities (long-term)[(a)]		**(4.3)**		11.4
Other long-term assets		**0.1**		0.3
Changes in operating assets and liabilities	**$**	**12.5**	$	3.1

(a) Inclusive of an increase in the revenue deficiency account (use of cash) of $1.0 million during the year ended December 31, 2022 (year ended December 31, 2021 – an increase in the revenue deficiency account (use of cash) of $1.9 million).

The following cash payments have been included in the determination of net income after taxes:

				Year ended December 31
		2022		2021
Interest paid	**$**	**29.0**	$	27.3
Income taxes paid (net of refunds)	**$**	**0.4**	$	(3.9)

23. SEGMENTED INFORMATION

The following describes the Company's three reporting segments:

Renewable Energy	–	Includes the 102 MW Bear Mountain Wind Park, and an approximately 10 percent indirect equity investment in Coast LP, which indirectly owns and operates three run-of-river hydroelectric power generation assets in northwest British Columbia.
Utilities	–	Includes the rate-regulated distribution assets in Alberta, British Columbia and Nova Scotia as well as an approximately 33.33 percent equity investment in Inuvik Gas Ltd.
Corporate	–	Includes the cost of providing shared services, financial and general corporate support, corporate assets as well as the equity investment in the NGIF Cleantech Ventures Limited Partnership.

The following tables show the composition by segment:

	Year ended December 31, 2022				
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 447.4**	**$ 17.9**	**$ —**	**$ —**	**$ 465.3**
Cost of sales	**(230.1)**	**(0.3)**	**—**	**—**	**(230.4)**
Operating and administrative	**(104.5)**	**(5.1)**	**(15.8)**	**—**	**(125.4)**
Accretion expense	**(0.1)**	**(0.1)**	**—**	**—**	**(0.2)**
Depreciation and amortization	**(37.3)**	**(7.3)**	**(0.1)**	**—**	**(44.7)**
Income (loss) from equity investments	**0.1**	**5.9**	**(0.2)**	**—**	**5.8**
Unrealized gain (loss) on risk management contracts	**(15.3)**	**—**	**8.4**	**—**	**(6.9)**
Other income	**2.5**	**—**	**—**	**—**	**2.5**
Operating income (loss)	**$ 62.7**	**$ 11.0**	**$ (7.7)**	**$ —**	**$ 66.0**
Interest expense	**(8.3)**	**—**	**(23.5)**	**—**	**(31.8)**
Income (loss) before income taxes	**$ 54.4**	**$ 11.0**	**$ (31.2)**	**$ —**	**$ 34.2**
Net additions (reductions) to:					
Property, plant and equipment[(a)]	**$ 148.7**	**$ —**	**$ 0.3**	**$ —**	**$ 149.0**
Intangible assets	**$ 2.4**	**$ —**	**$ —**	**$ —**	**$ 2.4**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash Flows due to classification differences.

	Year ended December 31, 2021				
	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 357.2	$ 19.9	$ —	$ —	$ 377.1
Cost of sales	(154.5)	(0.3)	—	—	(154.8)
Operating and administrative	(99.4)	(5.4)	(4.0)	—	(108.8)
Accretion expense	(0.1)	(0.2)	—	—	(0.3)
Depreciation and amortization	(32.8)	(7.3)	(0.1)	—	(40.2)
Income from equity investments	0.1	6.2	—	—	6.3
Unrealized gain on risk management contracts	2.2	—	—	—	2.2
Other Income	0.5	—	—	—	0.5
Foreign exchange loss	(0.3)	—	—	—	(0.3)
Operating income (loss)	$ 72.9	$ 12.9	$ (4.1)	$ —	$ 81.7
Interest expense	(5.7)	—	(22.4)	—	(28.1)
Income (loss) before income taxes	$ 67.2	$ 12.9	$ (26.5)	$ —	$ 53.6
Net additions (reductions) to:					
Property, plant and equipment[a]	$ 111.3	$ —	$ —	$ —	$ 111.3
Intangible assets	$ 10.3	$ —	$ 0.1	$ —	$ 10.4

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash Flows due to classification differences

The following table shows goodwill and total assets by segment:

	Utilities	Renewable Energy	Corporate	Total
As at December 31, 2022				
Goodwill	**$ 119.1**	**$ —**	**$ —**	**$ 119.1**
Segmented assets	**$ 1,669.8**	**$ 322.1**	**$ (74.5)**	**$ 1,917.4**
As at December 31, 2021				
Goodwill	$ 119.1	$ —	$ —	$ 119.1
Segmented assets	$ 1,487.8	$ 310.5	$ (49.6)	$ 1,748.7

24. SUBSEQUENT EVENTS

Subsequent events have been reviewed through March 8, 2023, the date on which these consolidated financial statements were approved for issue by the Board of Directors. Other than as disclosed under notes 4, 12, 17 and 18, there were no subsequent events requiring disclosure or adjustment to the consolidated financial statements.