BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

	)	
IN THE MATTER OF THE PETITION	)	
OF MINNESOTA POWER FOR	)	
ACQUISITION OF ALLETE BY CANADA	)	**MPUC Docket Nos. E-015/PA-24-198,**
PENSION PLAN INVESTMENT BOARD AND	)	**M-24-383**
GLOBAL INFRASTRUCTURE PARTNERS	)	**OAH Docket No. 25-2500-40339**
	)	

PUBLIC REDACTED

Direct Testimony of

Courtney Lane

On Behalf of

Sierra Club

February 4, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Courtney Lane. I am a Senior Principal at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue #3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the energy industry.

Q Please summarize your professional and educational experience.

A I have more than 20 years of experience in energy policy and regulation. At Synapse, I work on issues related to utility regulatory models, rate and bill impacts, and benefit-cost assessment frameworks. Prior to Synapse, I was employed by National Grid as the growth management lead for New England where I oversaw the development of customer products, services, and business models for Massachusetts and Rhode Island. In previous roles at National Grid, I worked on the deployment of non-wires alternatives ("NWA") and grid modernization efforts and led the development of annual and three-year energy efficiency plans. Prior to joining National Grid, I worked on regulatory and state policy issues pertaining to energy conservation, retail competition, net metering, and the Alternative Energy Portfolio Standard for Citizens for Pennsylvania's Future. Before that, I worked for Northeast Energy Efficiency Partnerships, Inc. where I promoted energy efficiency throughout the Northeast.

I hold a Master of Arts in Environmental Policy and Planning from Tufts University and a Bachelor of Arts in Environmental Geography from Colgate University. My resume is attached as Attachment CL-1.

Q Have you previously testified before the Minnesota Public Utilities Commission?

A No, I have not.

Q Have you previously submitted testimony in proceedings before other state commissions or agencies?

A Yes. I have testified and participated in regulatory proceedings before the Rhode Island Public Utilities Commission, the Pennsylvania Public Utility Commission, the New Hampshire Public Utilities Commission, the New Mexico Public Regulation Commission, and the Public Service Commission of the District of Columbia. A list of my previous testimony is contained in Attachment CL-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q What is the purpose of your direct testimony?

A The purpose of my testimony is to examine the proposed acquisition of all outstanding shares of ALLETE, Inc. ("ALLETE"), owner of Minnesota Power (the "Company"), by Canada Pension Plan Investment Board ("CPP Investments") and Global Infrastructure Partners ("GIP") (together, the "Partners") (the "Acquisition") and to determine if the proposed Acquisition is in the public interest.

Q How is your direct testimony structured?

A In Section II, I summarize my conclusions and recommendations. In Section III, I discuss the applicable standard of review. In Section IV, I provide a summary of the proposed Acquisition, the Company's ability to fund capital investments, and issues considered by the Federal Energy Regulatory Commission ("FERC"). In Section V, I explain how the proposed Acquisition creates risks to ratepayers. In Section VI, I explain how the proposed Acquisition threatens local control. In Section VII, I explain how the proposed Acquisition would not benefit ratepayers and decreases transparency. In Section VIII, I explain how the Partners' exit strategy threatens the Company's ability to comply with the carbon free standard. Lastly, in Section IX, I provide a conclusion.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A I find that the proposed Acquisition poses several probable harms to the public interest, including in relation to cost and risk, and that the Minnesota Public Utilities Commission (the "Commission") should not approve the Acquisition.

- The Partners' incentive to increase profits in the short term would likely lead to over investment in capital investments as opposed to demand-side solutions like greater efficiency or non-capital approaches like power purchase agreements ("PPA") from third parties. This capital bias is likely to lead to higher costs, which would ultimately be borne by ratepayers.

- Under the Partners' proposal, the Partners would largely control the post-Acquisition ALLETE Board of Directors ("ALLETE Board"), giving them significant control and influence over Minnesota Power's business plans and budgets. This would enable the Partners to direct investment (or over-investment) in capital, remove uncooperative management, and change corporate strategy.

- The proposed Acquisition would result in ALLETE becoming a private company and will no longer have to meet the strict reporting standards set by regulatory bodies such as the Securities and Exchange Commission ("SEC"). This reduces transparency and makes it more difficult for regulators to monitor company decisions and hold them accountable.

- The proposed Acquisition could threaten Minnesota Power's ability to meet state carbon reduction goals. For example, should the Company be sold in advance of its ability to cease coal operations, there is no guarantee that future owners would follow through on current plans to retire Minnesota Power's coal fleet. There is also a risk that the Partners will not follow through on their stated commitments to clean energy and, through their influence on the ALLETE Board, could direct the Company to change its coal retirement schedule after the Acquisition.

While there are numerous potential harms that could result from the Acquisition, the Partners and ALLETE do not commit to any benefits to ratepayers and provide no indication that the Acquisition will lead to lower costs to ratepayers.

Q Please summarize your recommendations.

A The Commission should not approve the proposed Acquisition because the potential harms of the transaction outweigh the uncertain, theoretical benefits, and the Acquisition is therefore not consistent with the public interest.

III. STANDARD OF REVIEW

Q What criteria does the Commission consider before approving a merger or acquisition?

A While I am not an attorney, I understand that the Commission may not approve a merger or acquisition unless it finds the transaction to be consistent with the public interest.[1] Neither statute nor the Petition[2] provides a definition for the public interest. However, the Commission has determined in prior merger and acquisition proceedings that for a transaction to be consistent with the public interest, the potential harms cannot outweigh the potential benefits. To determine if a proposed transaction is consistent with the public interest, "perceived detriments or concerns must be weighed against perceived benefits to

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[1] Minn. Stat. § 216B.50, subd. 1.

[2] *In the Matter of the Petition of Minn. Power for the Acquisition of ALLETE by Can. Pension Plan Inv. Bd. and Glob. Infrastructure Partners*, Docket No. E015/PA-24-198, Initial Filing – Petition for Approval (Minn. Pub. Util. Comm'n July 19, 2024) [hereinafter "Petition"].

the public."[3] If the potential harms of a transaction outweigh the potential benefits, the transaction is not consistent with the public interest unless conditions are imposed that sufficiently mitigate the harms. The Commission has denied acquisition petitions in cases where it finds that the harms outweigh the benefits. For example, in a 2019 case, the Commission denied Xcel's petition to acquire the Mankato Energy Center ("MEC"), concluding that "Xcel's acquisition of MEC has not been shown to be consistent with the public interest. The potential costs to ratepayers are too high, and the potential benefits too uncertain, to support the purchase."[4]

Q Has the Commission identified specific issues it will consider in evaluating whether the Acquisition is in the public interest?

A Yes, the Commission's October 7, 2024 Order identified the following issues for Parties to address in this proceeding:

(A) Are there any potential harms to the public interest from the proposed transaction, including in relation to cost or risk?

(B) Are there any potential benefits to ratepayers, Minnesota, or the public interest from the proposed transaction?

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[3] *In the Matter of the Proposed Merger of Minnegasco, Inc. with and into Arkla, Inc.*, Docket No. G008/PA-90-604, Order Approving Merger and Adopting Amended Stipulation with Modifications, 4 (Minn. Pub. Util. Comm'n Nov. 27, 1990).

[4] *In the Matter of a Petition by N. States Power Co. for Approval of the Acquisition of the Mankato Energy Ctr.*, Docket No. E-002/PA-18-702, Order Denying Petition and Requiring Supplemental Modeling, 10 (Minn. Pub. Util. Comm'n Dec. 18, 2019).

(C) Considering all relevant factors and applicable law, is the proposed transaction consistent with the public interest?

(D) Are there regulatory requirements or commitments necessary to render the proposed transaction consistent with the public interest?

(E) How do relevant and related dockets pending before the Federal Energy Regulatory Commission, Public Service Commission of Wisconsin, and/or other state, federal or foreign government agencies impact the Commission's consideration of the proposed transaction?

(F) How will the acquisition impact Minnesota Power's union and non-union workforce and do the protections included in the acquisition adequately protect that workforce?

(G) How will the acquisition impact Minnesota Power's ability to comply with the carbon-free standard under [Minn. Stat.] § 216B.1691, including any modifications of plans associated with the Nemadji Trail Energy Center [(a proposed 525-megawatt natural gas combined-cycle power plant to be built in Superior, Wisconsin)]?[5]

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[5] *In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners*, Docket No. E015/PA-24-198, Order for Hearing, 12 (Oct. 7, 2024).

IV. SUMMARY AND BACKGROUND OF THE PROPOSED TRANSACTION

A. Overview of the proposed Acquisition

Q Please provide a brief description of the parties to the Acquisition.

A ALLETE is a publicly traded utility company based in Duluth, Minnesota. Minnesota Power is an operating division of ALLETE, also based in Duluth, that has the exclusive right to provide retail electric service in a 26,000-square-mile area of central and northern Minnesota.[6] ALLETE's other regulated operations include Superior Water, Light & Power, an electric, water, and gas utility in Wisconsin, and 8 percent ownership in American Transmission Company, an independent transmission company in Wisconsin.[7] ALLETE also has investments in unregulated clean energy infrastructure through ALLETE Clean Energy and New Energy Equity.[8]

CPP Investments is a professional investment management organization that manages the Canada Pension Plan Fund on behalf of more than 22 million Canadians.[9] As of March 31, 2024, CPP Investments managed assets totally C$632.3 billion, with a United States investment portfolio of C$267.6 billion (approximately US$197.7 billion) invested directly and indirectly in equity and fixed income in public and private companies across a variety of sectors including in real estate, infrastructure, and energy.[10]

[6] Petition at 3-4.

[7] Petition at 4-5.

[8] *Id.* at 5.

[9] *Id.* at 6.

[10] *Id.*

GIP is a "infrastructure investor that specializes in investing in, owning, and/or operating some of the largest and most complex assets across the energy, transport, digital infrastructure, and water and waste management sectors."[11] GIP has approximately $115 billion in assets under management.[12] GIP is funding the proposed Acquisition through two funds, Global Infrastructure Partners V ("GIP Fund V") and Tower Bridge Infrastructure Partners, L.P. ("Tower Bridge").[13] GIP Fund V is managed by a GIP controlled affiliate with several limited partners, while Tower Bridge Fund is a fund managed by a GIP-controlled affiliate, with the California Public Employees' Retirement System ("CalPERS") as the sole limited partner.[14]

GIP was recently acquired by BlackRock, Inc. ("BlackRock").[15] Blackrock is a "publicly traded … investment management firm domiciled in the United States that provides investment management services to its mutual funds, investment accounts, and other investment funds."[16] Most notably, BlackRock owns 10.99 percent of Cleveland Cliffs

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[11] *Id*. at 7.

[12] *Id*.

[13] *Id.* at 10.

[14] *Id.* at 10, fns. 11, 12.

[15] Fed. Energy Regul. Comm'n, Docket No. EC24-58-000, Glob. Infrastructure Mgmt., LLC, Order authorizing disposition of jurisdictional facilities and acquisition of securities, 188 FERC ¶ 61,166 (Sept. 6, 2024); Glob. Infrastructure Mgmt., LLC, Docket No. EC24-58-000, Notice of Consummation (Oct. 7, 2024).

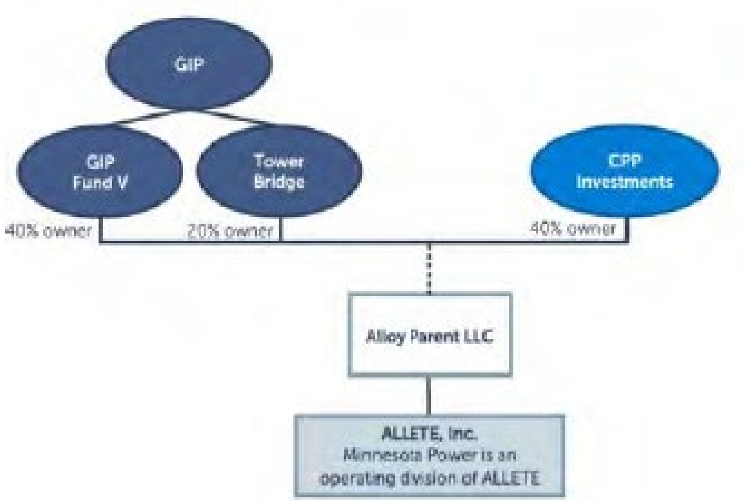
[16] *In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners*, Docket No. E015/PA-24-198, Supplemental Filing, 3 (Oct. 8, 2024) [hereinafter "Supplemental Filing"].

and 10.41 percent of U.S. Steel, which are two of Minnesota Power's six taconite customers and make up approximately 70 percent of the Company's industrial demand.[17]

Q Please provide a description of the proposed Acquisition.

A On, July 19, 2024, ALLETE, GIP, and CPP Investments (collectively, the "Applicants") filed their Petition before the Commission seeking approval of the proposed Acquisition.[18] According to the Petition, GIP and CPP Investments plan to form a new corporation, Alloy Parent LLC, to acquire all of ALLETE's shares and interests. This would result in CPP Investments indirectly owning 40 percent of ALLETE's outstanding common stock, and GIP indirectly owning 60 percent through two funds: GIP Fund V and Tower Bridge.[19] The resulting organizational structure would look as follows:

Figure 1. Post-Acquisition Organizational Structure



Source: Petition at 11, Figure 2.

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[17] Petitioners' Response to Citizens Utility Board ("CUB") Information Request ("IR") 106 (provided in Attachment ["Attach."] CL-2).

[18] *See* Petition.

[19] Petition at 10.

Q How does the Company describe the primary goal and benefit of the proposed Acquisition?

A The Company states that the purpose and overall goal of the Acquisition is to "enable Minnesota Power to obtain a reliable source for the significant additional equity capital it needs to continue and expand its investment in clean energy technology and systems."[20] The Company asserts that improved access to capital would be the "primary benefit" of the Acquisition.[21]

B. <u>Summary of Minnesota Power's ability to fund capital investments</u>

Q Has Minnesota Power had difficulty obtaining access to sufficient capital?

A No. Minnesota Power has not had difficulty obtaining access to sufficient capital when needed. While Company witness Taran asserts that ALLETE would likely have difficulty raising enough capital on public markets,[22] the Company has cited no instances of inability to raise enough capital and the Company's recent history indicates otherwise. ALETTE's 2023 Annual Report stated: "We are well positioned to meet our financing needs due to adequate operating cash flows, available additional working capital and access to capital markets."[23] MarketBeat's January 2025 report documented significant

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[20] Direct Testimony of Jennifer Cady (hereinafter "Cady Direct") at 7:16-19.

[21] Petitioners' Response to CUB IR 39(a) (provided in Attach. CL-2).

[22] Direct Testimony of Joshua Taran (hereinafter "Taran Direct") at 7:24-25.

[23] ALLETE, Inc. 2023 Form 10-K at 58 (provided as Attach. CL-7).

investment in ALLETE from major investment funds.[24] ALLETE is not struggling to raise capital on the public market.

ALLETE asserts that it is "the largest investor in renewable energy, relative to market capitalization, of all publicly traded utilities in the United States."[25] Over the last two years, ALLETE's stock price held relatively steady while the Company enjoyed growth.[26]

While ALLETE claims the purpose of the Acquisition is to improve access to capital, the Company has not demonstrated that it has or will have difficulty accessing capital. Company witness Taran argues that, even if ALLETE is able to raise sufficient capital from public markets, the cost of accessing public capital is variable and hard to predict.[27] But all markets have some degree of uncertainty, and the Company has not shown that raising capital in public markets would be unreasonably costly or difficult. Again, the

[24] According to Marketbeat's January 2025 report, in the last two financial quarters, State Street Corp raised its position in shares of ALLETE by 0.5%, Geode Capital Management LLC grew its stake by 1.6%, Dimensional Fund Advisors LP increased its position in ALLETE by 5.8%, Millennium Management LLC lifted its stake in ALLETE by 955.1%, and Charles Schwab Investment Management Inc. boosted its holdings in shares of ALLETE by 1.0%. MarketBeat, *ALLETE, Inc. (NYSE:ALE) Short Interest Up 7.8% in December* (Jan. 20, 2025), *available at* https://www.marketbeat.com/instant-alerts/allete-inc-nyseale-short-interest-up-78-in-december-2025-01-19/.

[25] Petition at 15.

[26] *See* MarketWatch, ALLETE Inc., *available at* https://www.marketwatch.com/investing/stock/ale (last visited Jan. 28, 2025); Investing.com, *Allete Stock Hits 52-Week High at $65.9 Amid Positive Annual Growth* (Jan. 21, 2025), *available at* https://www.investing.com/news/company-news/allete-stock-hits-52week-high-at-659-amid-positive-annual-growth-93CH-3822379.

[27] *See* Taran Direct at 7:7-11.

Company's recent track record indicates that it has not had trouble accessing capital. Company witness Taran acknowledges that "ALLETE has been able to navigate the risks of public markets in the past."[28] The Company presents the Acquisition as a solution to a purported problem but has not demonstrated that any such problem exists.

C. Issues FERC considered

Q Please describe the status of regulatory approvals of the Acquisition.

A FERC authorized the Partners' proposed Acquisition of ALLETE in December 2024.[29] Under the Federal Power Act, FERC evaluates whether proposed acquisitions are consistent with the public interest.[30] FERC considers three factors in analyzing whether a transaction is in the public interest: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[31] The Federal Power Act also requires FERC to consider whether a transaction will result in "cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company."[32] I am not an attorney, but I understand that FERC uses different criteria to evaluate proposed acquisitions than those used by the Commission. The Commission does not apply FERC's test to determine whether a transaction is in the public interest.

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[28] Taran Direct at 7:30-31.

[29] Fed. Energy Regul. Comm'n, Docket No. EC24-105-000, Order authorizing disposition of jurisdictional facilities and acquisition of securities, 1 (Dec. 19, 2024)[hereinafter "FERC Order"].

[30] 16 U.S.C. § 824b(a)(4); FERC Order at 14; *see also* Cady Direct at 9:18-19.

[31] Inquiry Concerning the Comm'n's Merger Pol'y Under the Fed. Power Act: Pol'y Statement, Order No. 592, FERC Stats. & Regs. ¶ 31,044, 30,111 (1996); FERC Order at 14; *see also* Cady Direct at 9:20-22.

[32] 16 U.S.C. § 824b(a)(4); FERC Order at 14; *see also* Cady Direct at 9:22-25.

Accordingly, I understand that FERC's approval of the proposed Acquisition does not determine the Commission's consideration of the public interest in this proceeding.

The Acquisition also needs approval from the Public Service Commission of Wisconsin, which I understand is pending, and approval from the Federal Trade Commission, which is not yet filed.[33]

V. THE PROPOSED ACQUISITION CREATES UNNECESSARY RISKS TO RATEPAYERS

Q What potential harms does the proposed Acquisition pose for Minnesota Power ratepayers?

A I am concerned that as private equity investors, GIP and CPP Investments would pursue higher returns from Minnesota Power's rate base instead of pursuing least-cost options. As I explain in more detail in this section, the incentives for private equity investors differ from ALLETE's equity holders as a publicly traded company in important ways. Ultimately, if the proposed Acquisition is completed, the Partners may pressure ALLETE to take actions that are likely to lead to higher costs, which would ultimately be borne by Minnesota Power ratepayers.

Q Please explain why private equity owners are motivated to pursue higher returns from an acquired utility such as Minnesota Power.

A The drive for higher returns for private equity can be understood and demonstrated both empirically and theoretically. Theory and empirical evidence both suggest that if the

[33] Cady Direct at 8:16-19, 9:1-6.

Acquisition is completed, the Partners would put pressure on ALLETE and Minnesota Power to increase returns.

The theoretical basis has to do with the motivations for private equity partners such as CPP Investments and GIP to pursue a private acquisition of a publicly traded company such as ALLETE. Since ALLETE is publicly traded, CPP Investments and GIP already have the option of buying equity shares in ALLETE. The fact that CPP Investments and GIP do not merely purchase equity in ALLETE through the public market, but rather aim to take ALLETE private, demonstrates that CPP Investments and GIP believe they can earn a greater return on investment through private ownership than they could by buying a stake in the public company. If they did not believe so, the Partners would simply purchase ALLETE stock.

Next, there is a strong empirical record of private equity returns exceeding returns of public stocks. To put it another way, on average, private equity investments have a better return than the stock market by a significant margin. One analysis of private equity returns reported by state pension funds identified an annualized return of 11 percent from 2000 to 2023, exceeding a 6.2 percent return in public stocks over the same period.[34] The return demanded by private equity is particularly high compared to utility stocks, which tend to grow more slowly than the stock market as a whole. For example, as of the end of 2023, Pitchbook's North American Private Equity Index had a five-year return of 18.3

[34] Stephen Nesbitt, Chartered Alternative Investment Analyst Association, *Long-Term Private Equity Performance: 2000 to 2023* (Apr. 23, 2024), *available at* https://caia.org/blog/2024/04/23/long-term-private-equity-performance-2000-2023.

percent, compared to 9.9 percent for the S&P 500.[35] But Morningstar's index of U.S. utilities had a five-year return of around 7 percent over the same period.[36]

Q **What does this empirical record suggest for the future of Minnesota Power post-Acquisition?**

A Minnesota Power would be in a position where its equity holders would be demanding a higher average return than has been demanded by ALLETE shareholders in the public markets. All else being equal, higher returns for Minnesota Power's shareholders can be achieved by growing the rate base through increased investments in capital infrastructure, growing the authorized return on equity by aggressively petitioning the Commission for a higher return on equity ("ROE"), or both.

Therefore, Minnesota Power will likely be under pressure to increase its rate base and seek ever-higher authorized ROEs in order to generate the higher return that would be demanded by its new owners following the Acquisition.

Q **Please explain why pressure from the Partners to increase Minnesota Power's return creates risks for ratepayers. ?**

A Due to the fact that Minnesota Power earns a return on capital expenditures ("CAPEX") and not operational expenditures ("OPEX"), pressure from the Partners to increase the return could lead to Minnesota Power choosing to invest in more expensive capital assets

[35] FS Investments, *Private equity has historically outperformed public markets* (June 14, 2024), *available at* https://fsinvestments.com/fs-insights/chart-of-the-week-2024-6-14-private-equity-outperformance/.

[36] *See* Morningstar U.S. Utilities (accessed Jan. 31, 2025), *available at* https://indexes.morningstar.com/indexes/details/morningstar-us-utilities-sector-FSUSA0B58K?currency=USD&variant=TR&tab=overview.

when there are lower cost OPEX solutions. The higher cost of this choice would ultimately borne by ratepayers. This is often referred to as a capital bias and can take many forms.[37] For example:

- The Partners may push the Company to invest in its own capital assets, like distribution and substation upgrades that add to rate base, instead of seeking third-party and customer-owned alternatives such as distributed energy resources ("DER") and non-wires alternatives that would be classified as OPEX and not add to rate base, even when the latter are more cost-effective for ratepayers.

- The Partners may have a bias toward Minnesota Power seeking self-owned or self-build projects rather than signing PPAs with third parties or making wholesale market purchases.

- The Partners may push the Company to hold onto assets for longer than may be in the public interest to avoid shrinking its rate base.

In addition to CAPEX bias over OPEX, pressure to grow the rate base may encourage the Company to overlook less capital-intensive, innovative approaches like grid-enhancing technologies, despite the benefits of those approaches.

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[37] The Averch-Johnson effect is identified by economists as the tendency of regulated companies to engage in excess capital investments to increase their profits. *See* Harvey Averch and Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 American Economic Review 1052 (1962), *available at* https://www.jstor.org/stable/1812181.

Q Please explain the innovative approaches that utilities, especially utilities owned by private equity firms, may overlook.

A A 2024 report from the U.S. Department of Energy examined the potential for "advanced grid solutions," defined as twenty technologies and applications that can unlock grid bottlenecks and unlock transmission and distribution capacity, especially when integrating renewable energy.[38] These advanced grid solutions include energy storage used as a distribution asset, aggregation of distributed energy resources through virtual power plants, advanced sensors to provide real-time data on grid conditions, and dynamic line rating of transmission lines.[39] The report found that together, these twenty solutions have the potential to expand U.S. grid capacity by 20 to 100 gigawatts "while improving grid reliability, resilience, and affordability."[40]

Among the biggest barriers to the deployment of the solutions identified by the report is the utility business model in which investor-owned utilities earn profit on capital expenditures but pass the costs of operating expenditures onto customers without a return.[41] The report found that "[t]his business model can disincentivize investments in innovative technologies that have relatively lower CAPEX costs, have higher OPEX, improve system efficiency, or facilitate integration of third-party owned generation and storage" such as distributed energy resources or virtual power plants.[42] Advanced grid

[38] U.S. Department of Energy, *Pathways to Commercial Liftoff: Innovative Grid Deployment*, (Apr. 2024), *available at* https://liftoff.energy.gov/wp-content/uploads/2024/05/Liftoff_Innovative-Grid-Deployment_Final_5.2-1.pdf.

[39] *Id*. at 2.

[40] *Id.* at 3.

[41] *See id*. at 54.

[42] *Id*.

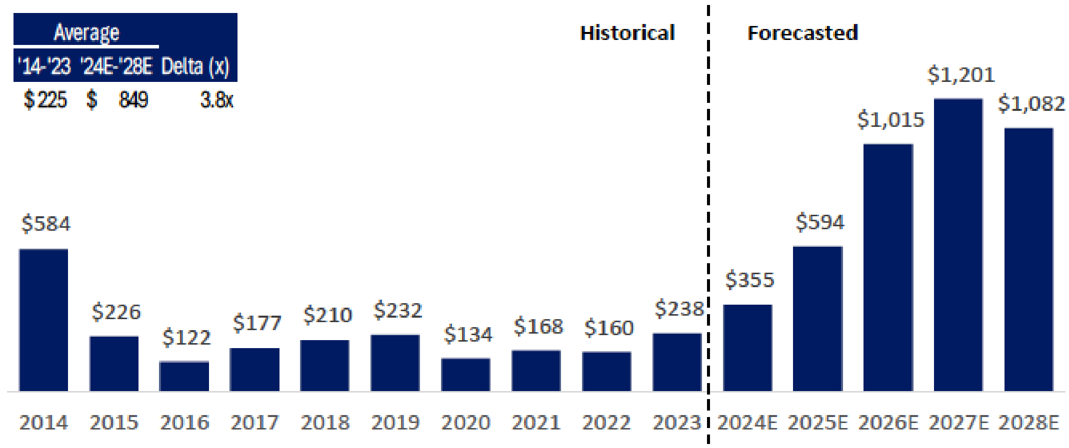
solutions serve the public interest by providing affordable options for integrating clean energy while maintaining reliability. But investor-owned utilities such as ALLETE lack the financial incentives to pursue these solutions. The burden is on stakeholders and regulators to push utilities to use innovative approaches. This burden on stakeholders and regulators only grows when private equity owns utilities. If the proposed Acquisition occurs, Minnesota Power would be more likely to ignore innovative, low-CAPEX solutions due to the greater pressure to provide high returns to its equity owners.

Q Is there any specific evidence that ALLETE intends to more aggressively grow Minnesota Power's rate base through capital expenditures after the proposed Acquisition?

A Yes. Company witness Taran states that "[o]ver the next five years, ALLETE's regulated capital plan of over $4 billion represents a dramatic increase compared to historical investments" and that "[t]he Company's five-year capital needs represent an approximately 3.8-times increase in regulated investment compared to the historical ten-year average," as shown in the following figure.[43]

[43] Taran Direct at 5:23-27.

Figure 1. ALLETE Regulated Operations – Historical and Forecasted Capital Expenditures[5] ($ in millions)



Source: Taran Direct at 6, Figure 1.

GIP witness Bram states in direct testimony that the "scale" at which Minnesota Power must invest "unprecedented capital" in its generation fleet and also invest in its transmission and distribution systems "make ALLETE an attractive investment opportunity for GIP."[44] **[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]** [redacted]

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[44] Direct Testimony of Jonathan Bram ("Bram Direct") at 4.

[45] Petitioners' Response to CUB IR 118, Attachment CUB IR 0118.01 Attach HCTS at 6-7 (provided in Attach. CL-4).

[46] *Id*. at 10.

[redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]**

Q Given the incentives and biases outlined above, is there cause for concern that the proposed Acquisition may lead Minnesota Power to pursue capital investments that are larger than necessary?

A Yes. Given the pressure for higher returns and the utility capital bias discussed above, there is cause for concern that Minnesota Power may pursue capital investments that are more costly than necessary. Company witnesses cite the investments in clean energy needed to comply with Minnesota's Carbon Free Standard as justification for the planned increase in capital spending, but overlook alternatives for compliance with the standard, such as PPAs to procure renewable power from third parties. However, because the costs of PPAs are passed on to customers as an expense without a return for the utility, there is the risk of underinvestment in these approaches.

VI. THE PROPOSED ACQUISITION THREATENS LOCAL CONTROL

Q Please describe the makeup of the current ALLETE Board.

A The ALLETE, Inc. Corporate Governance Guidelines adopted by the ALLETE Board indicate that ALLETE believes that the board's size should range from nine to fifteen

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[47] *Id*. at 14.

[48] *Id*. at 15.

Directors as provided in the Articles of Incorporation.[49] The ALLETE Corporate Governance Guidelines also indicate that a "substantial majority of the Board's Directors shall be independent."[50]

Q How would the ALLETE Board change should the Acquisition be approved?

A If the Acquisition is approved, there will be a new ALLETE Board,[51] and GIP and CPP Investments will appoint ALLETE Board Directors who will hold customary board responsibilities, "including budgetary approvals, capital issuances, acquisitions and divestitures, and fundamental changes and actions consistent with customary board obligations, to jointly govern ALLETE through the exercise of consent rights."[52]

Q Do the Partners commit to maintaining a substantial majority of independent Directors on the Board after the Acquisition?

A No. The Merger Agreement only includes a commitment that two members of the ALLETE Board be independent directors.[53] The Applicants state that upon closing of the Acquisition, the ALLETE Board will include: (a) at least one member from Minnesota, (b) at least one member from Wisconsin, (c) at least two independent directors, and (d) the chief executive officer of ALLETE.[54] If the ALLETE Board continues to have

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[49] ALLETE, Inc. Corporate Governance Guidelines, 1 (Oct. 23, 2024), *available at* https://allete.blob.core.windows.net/allete/Documents/Governance/corporate-governance-guidelines.pdf.

[50] *Id*.

[51] Minn. Power Response to Sierra Club IR 35(e-f) (provided in Attach. CL-2).

[52] Minn. Power Response to Sierra Club IR 15(a-c) (provided in Attach. CL-2).

[53] Petition, Attachment B at 66.

[54] Minn. Power Response to Sierra Club IR 20(b) (provided in Attach. CL-2).

between 9 and 15 directors, it is likely the independent directors will have limited ability to influence outcomes.

Q Do the Partners explain the process for appointing directors to the ALLETE Board and the number of directors?

A When asked for specifics related to the ALLETE Board selection process, the Partners state that "[n]either the members of the ALLETE Board following the Acquisition nor any process for changing the numbers of board members has been determined."[55] But while the Partners state that this process has not been determined, **[HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE BEGINS]** [redacted]

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[55] Minn. Power Response to Sierra Club IR 20(b,f) and 41(b) (provided in Attach. CL-2.)

[56] Minn. Dept. of Commerce ("DOC") IR 0011.01 Attach HCTS (provided in Attach. CL-5).

[57] *Id*. at 2.

[58] *Id*. at 3.

[redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE ENDS]**

Q **Do the Partners indicate the level of control the ALLETE Board will have over Minnesota Power?**

A **[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]** [redacted]

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[59] *Id*. at 2.

[60] *Id*. at 2-3.

[61] Petitioners' Response to DOC IR 81(a) (provided in Attach. CL-2).

[62] DOC IR 0011.01 Attach HCTS at 2-3 (provided in Attach. CL-5).

[63] DOC IR 0006.01 Attach HCTS at 42 (provided in Attach. CL-4).

[redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]**

Q What is your concern with the proposed structure of the post-Acquisition ALLETE Board and the control the board will have over Minnesota Power?

A I am concerned that GIP and CPP Investments would control or otherwise have influence on the ALLETE Board. **[HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE BEGINS]** [redacted]

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[64] Petitioners' Response to DOC IR 81(b) (provided in Attach. CL-4).

[65] DOC IR 0011.01 Attach HCTS at 6 (provided in Attach. CL-5).

[redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE ENDS]**

Q **The Partners indicate they will not be involved in the day-to-day operation of Minnesota Power.[66] Does that alleviate your concerns?**

A No, it does not. While the Partners may not be directly involved in Minnesota Power's daily operational decisions, they seek to have control of the ALLETE Board. The Board guides the Company's day-to-day operations, and approves the Company's budget and strategic plans.[67] [**HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE BEGINS]** [redacted] [redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET NOT FOR ALLETE ENDS]**

This level of control and influence is concerning because decision-making regarding Minnesota Power's business plans and operating and capital budgets will shift away from local oversight to the Partners, which as summarized earlier in my testimony, have an

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[66] Petitioners' Response to CUB IR 0123(b) (provided in Attach. CL-2); Supplemental Filing at 4.

[67] Minn. Power Response to Sierra Club IR 69(b), (c) (provided in Attach. CL-2).

[68] Minn. Power Response to Sierra Club IR 80(c) (provided in Attach. CL-5).

incentive to drive an increase in Minnesota Power's rate base and do not have the same vested long-term interest in the health of Minnesota Power.

Q Please explain why the Partners' interests are misaligned with the long-term health of Minnesota Power.

A Lenders to private equity buyout transactions typically have shorter-term horizons than normal utility debtholders. Here, the Partners claim in testimony that they have a focus on long-term investment horizons, not short-term returns.[69] However, the Partners have refused to specify how long they plan to hold their investment in ALLETE.[70] Moreover, evidence indicates that at least some of the Partners hold many of their investments for a relatively limited term. For instance, **[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]** [redacted] [redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]** The Partners' short-term outlook to maximize profits to meet its debt obligations and to recover the Acquisition premium[72] is in conflict with Minnesota

[69] Bram Direct at 7; Direct Testimony of Andrew Alley at 6.

[70] Petitioners' Responses to CUB IRs 122(c), 130(a) (provided in Attach. CL-2).

[71] DOC IR 0006.01 Attach HCTS at 44-45 (provided in Attach. CL-4).

[72] Minn. Power Response to DOC IR 43(a) (provided in Attach. CL-2) ("[T]he $67 per share consideration payable to shareholders represents a premium of approximately 19 percent relative to the unaffected closing price for shares of ALLETE common stock on December 4, 2023.")

Power's need for long-term planning via its IRP and Integrated Distribution Planning Process.

Q Do the Partners provide any commitments that they will never influence ALLETE Board decisions regarding who should be on Minnesota Power's management team?

A No. When asked in discovery if the Partners would commit to never influencing ALLETE Board decisions regarding who should be on Minnesota Power's management team, the Partners did not answer.[73] Instead, the Partners' response asserts that they cannot speculate regarding future management team decisions or other future situations involving the ALLETE Board.[74]

The Merger Agreement states that "[t]he Company will agree to maintain the current senior management team consistent with the terms otherwise set forth in Section 6.10, subject to changes to account for voluntary departures or terminations in the ordinary course, including termination for failure to be in good standing with the Company or any Company Subsidiary or any of their respective policies."[75] However, the Merger Agreement does not contain any commitment related to maintaining senior management for more than two years, nor any commitment from the Partners that they will not pressure senior management to voluntarily depart.

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[73] Petitioners' Response to CUB IR 59 (provided in Attach. CL-2).

[74] *Id.*

[75] Petition, Attachment B, Section 6.06(b)(i)(5) at 66.

This is an area of concern because without a firm commitment in the Merger Agreement, there is nothing preventing the Partners from removing uncooperative management (i.e., management that is not aligned with the Partners) from Minnesota Power.

Q Do you have an example of a private equity firm influencing the appointment of a utility CEO?

A Yes. In 2021, Blackstone Infrastructure Partners invested $1 billion in common equity to support FirstEnergy's smart grid and clean energy transition initiatives.[76] As part of that transaction, FirstEnergy also agreed to appoint a Blackstone Infrastructure Partners-selected representative to its board of directors.[77] In March of 2023, FirstEnergy announced that a Blackstone executive, Brian Tierney, would take over as President and CEO of FirstEnergy Corp.

Q Have the Petitioners demonstrated that the post-Acquisition ALLETE Board would operate in a manner consistent with the public interest?

A No. The Partners and ALLETE have not committed to having the majority of the ALLETE Board directors be independent of the Partners and any affiliate. A director is considered independent if she or he is neither an employee of GIP or CPP Investments, Alloy Parent LLC, subsidiaries, or other affiliates. Because there is no guarantee that he majority of directors will be independent, the Commission should be concerned that the ALLETE Board may not act in the best interests of Minnesota Power and may be subject

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[76] PR Newswire, *FirstEnergy Announces Transformative $3.4 Billion of Equity Financings, Introduces Long-Term Earnings Growth Rate of 6-8%* (Nov. 7, 2021), *available at* https://www.prnewswire.com/news-releases/firstenergy-announces-transformative-3-4-billion-of-equity-financings-introduces-long-term-earnings-growth-rate-of-6-8-301418068.html.

[77] *Id.*

to undue influence. The Commission should therefore not approve the Acquisition as proposed.

VII. THE PROPOSED ACQUISITION WOULD NOT BENEFIT RATEPAYERS AND DECREASES TRANSPARENCY

Q Is there evidence that the proposed acquisition will result in tangible benefits to ratepayers?

A No. The Applicants do not commit to any benefits to ratepayers and have not demonstrated any ratepayer benefits. There is no indication that the proposed Acquisition will lead to lower costs for ratepayers. **[TRADE SECRET BEGINS]** [redacted] **[TRADE SECRET ENDS]**

The sole purpose of the proposed Acquisition is to provide access to capital, but ALLETE has had no trouble accessing capital from public markets, as discussed above, and can use third-party PPAs to support compliance with Minnesota law.

[78] Minn. Power Response to Sierra Club IR 26, Attachment SIERRA IR 0026.02 Attach TS (provided in Attach. CL-3).

Q Would Minnesota Power ratepayers have the same ability to judge the benefits brought to them by their utility post-Acquisition as they do now?

A No. The ability for ratepayers to scrutinize the operation of their utility would be greatly reduced by a lack of transparency that comes with private equity ownership.

Q Can you explain why a private equity acquisition might reduce transparency?

A Yes. Currently, because ALLETE is publicly traded, it must adhere to strict reporting standards set by regulatory bodies such as the SEC. These standards require regular, detailed disclosures on operations, finances, and risks. In addition, publicly-held utilities typically provide bond rating agencies with substantial information (often beyond that provided to the SEC), including financial projections, workforce projections, potential legal issues, etc.[79]

In contrast, private equity-owned companies are not subject to the same level of public reporting and do not provide detailed information about the acquiring firms' other investments. This is problematic for several reasons.

The reduction in reporting requirements means that critical information about the company's performance, strategic decisions, and potential risks can be obscured from public view. Consequently, regulators have less insight into the company's operations and financial health, which undermines transparency and accountability. Specifically, regulators have less ability to monitor the company's decisions and hold management

[79] Stephen Hill, *Private Equity Buyouts of Public Utilities: Preparation for Regulators,* 42 (Dec. 2007), *available at* https://pubs.naruc.org/pub/FA86433D-A820-85E7-B1C7-D3038BF5155E.

accountable for practices that could lead to inefficiencies or excessive profits at the expense of the public interest.

The risks associated with the rest of the private equity firm's portfolio are likely to be greater than that of the utility, and can thus affect the risk attributed to the utility acquired by the private equity firm.[80] This issue is compounded by the lack of public information about the rest of the portfolio. As noted in a report published by the National Regulatory Research Institute, "[t]his lack of information can cause bond rating agencies to impute higher risk to the private equity transaction, which translates into higher capital costs."[81]

Q How does public ownership ensure accountability in ways that might be lost under private equity ownership?

A Publicly traded companies, especially those in critical infrastructure sectors like utilities, are held accountable through a combination of regulatory oversight, investor scrutiny, and public reporting. Public ownership forces a company to regularly report performance metrics, engage with a diverse shareholder base, and face questions from regulatory bodies and the media. This level of accountability helps ensure that decisions are made in the public interest. Under private equity ownership, many of these layers of accountability are weakened or removed, leaving fewer checks and balances on potentially profit-driven decisions that could disadvantage ratepayers.

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[80] *Id.* at 30.

[81] *Id*. at 31.

VIII. THE PARTNERS' EXIT STRATEGY THREATENS MINNESOTA POWER'S ABILITY TO COMPLY WITH THE CARBON FREE STANDARD

Q Please describe Minnesota's Carbon Free Standard.

A In 2023, the Minnesota legislature enacted a Carbon Free Standard which requires electric utilities to provide Minnesota customers with power that is 100 percent carbon free by 2040.[82]

Q Please describe Minnesota Power's decarbonization goals.

A Minnesota Power set forth a goal of reducing carbon emissions by 80 percent by 2035 in its Commission-approved 2021-2035 IRP (Docket No. E015/RP-21-33).[83] An update on the Company's resource planning and plan for compliance with Minnesota's Carbon Free Standard is expected to be included in the Company's next IRP to be filed March 3, 2025.[84]

To help achieve the 80 percent reduction in carbon emissions by 2035, the Company intends to cease coal generation at Boswell Energy Center Unit 3 by December 31, 2029, and at Boswell Energy Center Unit 4 by 2035.[85]

Q Please explain how the proposed Acquisition could harm Minnesota Power's ability to comply with the Carbon Free Standard.

A The proposed Acquisition could harm Minnesota Power's ability to comply with the Carbon Free Standard in several ways. First, while the Partners currently claim to support

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[82] Minn. Stat. § 216B.1691; *see* Cady Direct at 17.

[83] Minn. Power 2021 Integrated Res. Plan, Docket No. E015/RP-21-33 at 3 (Feb. 1, 2021).

[84] Minn. Power Response to Sierra Club IR 8(a) (provided in Attach. CL-2).

[85] Minn. Power Response to Sierra Club IR 25(a-b) (provided in Attach. CL-2).

Minnesota Power's planned transition to clean energy sources, there is no guarantee that the Partners will not seek to change the Company's planned coal retirement dates after the Acquisition is complete, as discussed below. Second, the Partners could exit and sell their shares prior to the Company retiring its coal generation. There is no guarantee that the next owners of ALLETE will support Minnesota Power's plans to cease operation of its coal units, and as explained in the previous section of this testimony, future owners are likely to seek control of the ALLETE Board, which includes approval of Minnesota Power's budgets and business plans.

Q Do the Partners commit to owning ALLETE for a set period of time?

A No. When asked what commitments CPP Investments is making to the Commission in terms of the number of years it will own ALLETE shares, CPP Investments stated that "CPP Investments does not have a pre-determined hold period or fund life for its infrastructure investments."[86] Similarly, when asked to provide the number of years for which GIP is committing to not selling its shares in ALLETE, GIP responded that "GIP has not otherwise made a determination regarding the specific length of time GIP will continue investments by GIP Fund V."[87]

This lack of commitment is concerning, since **[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]** [redacted]

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[86] Petitioners' Response to CUB IR 122(c) (provided in Attach. CL-2).

[87] Petitioners' Response to CUB 130(a) (provided in Attach. CL-2).

[88] DOC IR 0006.01 Attach HCTS at 44-45 (provided in Attach. CL-4).

[redacted] **[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]**

Q Does the fact that the Commission approved Minnesota Power's 2021 IRP and directed the Company to cease coal operations at Boswell Unit 3 by December 31, 2029, and Boswell Unit 4 by 2035[89] alleviate your concerns?

A No. Sierra Club and other organizations filed comments and expert analysis in Minnesota Power's 2021 IRP proceeding concluding that retirement of Boswell Unit 4 *before* 2035 was in the best interest of ratepayers.[90] Moreover, there is a risk that Minnesota Power may later seek to postpone the planned retirement dates of the Boswell coal units. There are examples of utilities backing out of commitments made in IRPs, including those directed by commissions. For example, in 2020 the Mississippi Public Service Commission ("Mississippi PSC") issued an order in the Reserve Margin docket, 2018-AD-145, directing Mississippi Power Company ("MPC") to retire 950 MW of fossil generation by "year-end 2027 or show cause with detailed evidence why the continued operation of some or all of MPC's existing fossil steam generation is in the best interest of customers and MPC."[91] Accordingly, in its 2021 IRP, Mississippi Power adopted planned retirements for the majority of its fossil steam fleet, including a plan to retire the

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[89] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E-015/RP-21-33 at 13 (Minn. Pub. Util. Comm'n Jan. 9, 2023).

[90] *See* Clean Energy Organizations' Initial Comments, Docket No. E-015/RP-21-33 (Apr. 29, 2022) (provided as Attach. CL-6); *see also* Energy Futures Group and Applied Economics Clinic, A Clean Energy Alternative for Minnesota Power (Apr. 2022), *available at* https://www.edockets.state.mn.us/documents/%7B70C77680-0000-CB27-874E-28D1CE711075%7D/download?contentSequence=0&rowIndex=452.

[91] *In re Miss. Power Co.'s Rsrv. Margin Plan Filing*, Docket No. 2018-AD-145, Reserve Margin Plan, Final Order, 5-6 (Miss. Pub. Serv. Comm'n Dec. 17, 2020).

Daniel Coal plant by December 2027.[92] However, on January 9, 2025, MPC sent a notification to the Mississippi PSC that it had entered into two separate electric service agreements that will require the extension of the Daniel Coal plant retirement date into the mid-2030s.[93] The electric service agreements are to provide MPC's sister company, Georgia Power, with 750 MW of energy from 2024 through 2028 to support anticipated load from new data centers entering the state.[94]

Q Are you aware of other examples of utilities changing the date of planned fossil fuel unit retirements?

A Yes. Table 1 below provides a list of utilities that committed to retire coal plants either within an IRP or through a climate plan and that subsequently postponed the announced retirement dates.

Table 1. Changes in Utility Commitments to Coal Plant Retirement

Utility / Plant	Original Commitment	Change in Commitment	Emission Reduction and clean Energy Goals
Wisconsin Electric Power Co (WEPCO) / Four units at South Oak Creek Plant	Units 5 and 6 were set to retire in 2023 and Units 7 and 8 were set to retire in 2024.	One year delay of Units 5 and 6 until May 2024 and an 18-month delay of Units 7 and 8 until late 2025 due to tight energy supply conditions within the Midwest and	WEPCO to stop coal generation by 2035, 80 percent reduction by

[92] *In re Miss. Power Co.'s 2021 Integrated Res. Plan Filing*, Docket No. 2019-UA-231, Integrated Res. Plan (Miss. Pub. Serv. Comm'n July 20, 2021).

[93] *In re Miss. Power Co.'s Notice of IRP Cycle Pursuant to Comm'n Rule 29*, Docket No. 2019-UA-231 (Jan. 9, 2025).

[94] *See* Darrell Proctor, *Demand from Data Centers Keeping Coal-Fired Plants Online*, Power Magazine (Oct. 16, 2024), *available at* https://www.powermag.com/power-demand-from-data-centers-keeping-coal-fired-plants-online/.

Utility / Plant	**Original Commitment**	**Change in Commitment**	**Emission Reduction and clean Energy Goals**
		supply chain issues for renewable projects. [95]	2030.[96, 97] Wisconsin has 2050 100% clean energy target.[98]
Wisconsin Power and Light (Alliant) / Edgewater Generating Station	Edgewater was set to retire in 2022.	Retirement of generation station delayed from 2022 until June 2025.[99] Cited reasons are managing regional capacity and supply chain challenges with solar installation.[100]	Alliant to stop coal generation by mid-2026. Alliant to reach 50 percent reduction of CO2 emissions by 2030 and retirement of coal by 2040.[101]

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[95] We Energies, *We Energies announces new timeline for Oak Creek plant retirements* (June 23, 2022), *available at* https://news.we-energies.com/we-energies-announces-new-timeline-for-oak-creek-plant-retirements/.

[96] Danielle Kaeding, *Wisconsin's largest utility company plans to drop coal by 2035*, Wisconsin Public Radio (Nov. 4, 2021), *available at* https://www.wpr.org/economy/wisconsins-largest-utility-company-plans-drop-coal-2035.

[97] We Energies, *We Energies announces new timeline for Oak Creek plant retirements* (June 23, 2022), *available at* https://news.we-energies.com/we-energies-announces-new-timeline-for-oak-creek-plant-retirements/.

[98] Wisconsin Office of Sustainability and Clean Energy, *State of Wisconsin Clean Energy Plan Progress Report* (Aug. 2024), *available at* osce.wi.gov/PublishingImages/Pages/cleanenergyplan/2024 Clean Energy Plan Progress Report.pdf.

[99] Brandon Reid, *Edgewater Generating Station in Sheboygan focus of upcoming forum, plus more news in weekly dose*, Sheboygan Press (July 25, 2022), *available at* https://www.sheboyganpress.com/story/news/2022/07/25/edgewater-generating-station-sheboygan-closing-2025-forum-set/10125974002/.

[100] Alliant Energy, *Alliant Energy adjusting timing of its Wisconsin-based generation retirement dates to bolster reliability during transition to cleaner energy future* (June 23, 2022), *available at* https://www.alliantenergy.com/alliantenergynews/newscenter/23-generationupdate.

[101] Alliant Energy, *Clean Energy Blueprint and Vision* (last accessed Feb. 4, 2025), *available at* https://www.alliantenergy.com/cleanenergy/ourenergyvision/cebvision?utm_source=WS&utm_campaign=operationsWInewsreleaseJune2022.

Utility / Plant	Original Commitment	Change in Commitment	Emission Reduction and clean Energy Goals
Dominion Energy VA / Clover Power Station, Virginia Hybrid Energy Center, Mt. Storm Generating Station	Per Dominion Energy Virginia's 2020 IRP, Clover Units 1 and 2 were planned for retirement in 2025.	Clover Units 1 and 2 are now planned to remain online through 2045.[102] The retirement date change was part of several retirement date changes in Dominion's 2023 IRP. The IRP, and timelines for unit retirement, were contested by Synapse.	Virginia requires fossil-fueled generation to be retired by 2045.[103]
Santee Cooper / Winyah Generating Station	Per Santee Cooper's 2020 IRP, Winyah was set to phase out between 2023 and 2027.[104]	Winyah is now set to retire in 2030 as part of the 2023 Santee Cooper IRP. The IRP, and timelines for unit retirement, were contested by Synapse.[105]	Santee Cooper has an emissions reduction goal of 50 percent carbon emission reduction by the 2030s.[106]
Duke Energy Indiana / Gibson Units 3, 4, and 5	Per Duke Indiana's 2021 IRP preferred portfolio, Gibson Units 3, 4, and 5 were set to retire in 2029, 2029,	Per the 2024 rate case, Gibson Units 3, 4, and 5 now have scheduled closure dates of 2031, 2031, and 2030.[108]	Parent company Duke Energy Corporation has 50% carbon reduction by 2030 goal and net-zero by 2050 goal.[109]

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[102] *In re Va. Elec. and Power Co.'s 2023 Integrated Res. Plan,* Docket No. PUR-2023-00066, Direct Testimony of Devi Glick on behalf of Sierra Club, 9:3, 13:15 (Virginia Corp. Comm'n Aug. 30, 2023), *available at* synapse-energy.com/sites/default/files/Glick Revised Public %28Clean%29 23-066.pdf.

[103] *Id. at* 8:3-10.

[104] *In re 2023 Integrated Res. Plan for S.C. Pub. Serv. Auth.*, Docket No. 2023-154-E, Direct Testimony of Devi Glick on behalf of Sierra Club (Corrected), 57:19-58:3 (S. Carolina Pub. Serv. Comm'n Oct. 17, 2023), *available* at synapse-energy.com/sites/default/files/Docket No. 2023-154-E Public Glick Test Corrected 10.17.23 Clean 23-030.pdf.

[105] *Id.*

[106] Santee Cooper, *Environment* (last accessed Feb. 4, 2025)*, available at* https://www.santeecooper.com/Environment/.

[108] *Petition of Duke Energy Indiana LLC,* Cause No. 46038, Intervenor Exhibit No. 4, Direct Testimony of Devi Glick on Behalf of Citizens Action Coalition of Indiana, 15, Table 2 (Ind. Util. Reg. Comm'n Aug. 29 2024), *available at* https://iurc.portal.in.gov/docketed-case-details/?id=d1e0c3f4-9bf2-ee11-904c-001dd80b3d60

[109] Duke Energy, *Duke Energy aims to achieve net-zero carbon emissions by 2050* (Sept. 17, 2019), *available at* https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

Utility / Plant	Original Commitment	Change in Commitment	Emission Reduction and clean Energy Goals
	and 2025 respectively.[107]		
Duke Energy North Carolina	Per the 2022 Carbon Plan from Duke, Cliffside Unit 5 was set to retire in 2026, Mayo in 2029, Roxboro Units 3 & 4 in 2028 through 2034, and Marshall Units 3 & 4 in 2033.[110]	Per the 2023 Resource Plan pathway P3, retirements for coal plants are delayed for: Cliffside Unit 5 until 2031, Mayo until 2031, and Roxboro Units 3 & 4 until 2034. Marshall Units 3 & 4 are accelerated to 2032 retirement.[111]	North Carolina has a requirement that a resource portfolio achieve 70% carbon reduction by 2030. This was waived by NCUC in approving the coal retirement delays.[112]

Q The examples you provide pertain to publicly traded companies. Will the risk of delayed coal plant retirements remain a concern if the Acquisition is approved and ALLETE becomes a privately held company?

A Yes, the risk of delayed coal plant retirements is likely to be even more of an issue with private equity. Private firms tend to hold onto coal assets longer than traditional utilities. While "traditional utilities are under pressure from activist shareholders to reduce

[107] *Petition of Duke Energy Indiana LLC,* Cause No. 46038, Intervenor Exhibit No. 4, Direct Testimony of Devi Glick on Behalf of Citizens Action Coalition of Indiana, 15, Table 2 (Ind. Util. Reg. Comm'n Aug. 29 2024), *available at* https://iurc.portal.in.gov/docketed-case-details/?id=d1e0c3f4-9bf2-ee11-904c-001dd80b3d60

[110] *In the Matter of Biennial Consol. Carbon Plan and Integrated Res. Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC*, Docket No. E-100, Sub 190 Order accepting stipulation, granting partial waiver of commission rule R8-60A(d)(4) and providing further direction for future planning, 55, Table NC-4, 60 (N.C. Util. Comm'n Nov. 1, 2024), *available at* starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=cfc6d586-12e4-447f-a552-757d6e73c30e#page=53.22.

[111] *Id.*

[112] *Id.* at 176.

greenhouse gas emissions and to limit debt,"[113] private equity does not have that activist shareholder voice and is not subject to the same pressures.

Q Should the next owners of ALLETE not support renewable energy and Minnesota's carbon reduction goals, wouldn't Minnesota Power still need to retire its coal fleet by the currently planned dates to comply with the Carbon Free Standard?

A Not necessarily. In lieu of generating or procuring energy directly to satisfy the Carbon Free Standard, an electric utility may use renewable energy credits ("RECs") to satisfy the standard.[114] In addition, I understand that the Commission is still working on the implementation of the standard and has recently opened a new docket (No. E-999/CI-24-352) to investigate mechanisms for full and partial compliance with the Carbon Free Standard.[115] The decision in this docket is not anticipated until December 31, 2025, which is likely after a determination on the proposed Acquisition will be made.[116] Given the uncertainties surrounding how the Carbon Free Standard will be implemented and the available pathways for Minnesota Power to comply with the standard, there is no guarantee that the Company's remaining coal units will be retired by their currently planned retirement dates.

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[113] Tim McLaughlin, *How private equity squeezes cash from the dying U.S. coal industry*, Reuters (Mar. 2, 2021), *available at* https://www.reuters.com/article/world/how-private-equity-squeezes-cash-from-the-dying-us-coal-industry-idUSKBN2AU1YS/.

[114] Minn. Stat. § 216B.1691, Subd. 4(b).

[115] Order Investigating New Docket and Clarifying "Environmental Justice Area," Docket Nos. E-999/CI-23-151 and E-999/CI-24-352 (Minn. Pub. Util. Comm'n, Nov. 7, 2024).

[116] *Id.*

Q In addition to the threat of an early exit or sale by the Partners, do you have any other concerns about the impact of the Acquisition on the retirement of Minnesota Power's coal fleet?

A Yes. Even though the Company asserts that a primary motivation for the proposed Acquisition is to "provide Minnesota Power and, thus, its customers access to capital that will allow for compliance with the Minnesota Carbon Free Standard and accelerated renewable energy standard under Minn. Stat. § 216B.1691,"[117] the Partners have not committed to following Minnesota Power's announced coal retirement schedule for the Boswell units. This is a concern because priorities can change. Because the Partners have not stated a binding, enforceable commitment to coal plant retirement dates in the Merger Agreement or elsewhere, there is nothing preventing the Partners from changing their position after the Acquisition is approved.

IX. CONCLUSION

Q Please summarize your primary conclusions and recommendations.

A I find that the proposed Acquisition poses several potential harms to the public interest, including in relation to cost and risk, and should not be approved as proposed. The Partners have an incentive to increase profits in the short term, which encourages overinvestment in capital investments rather than lower-cost solutions that would increase the costs ultimately borne by ratepayers. This risk would be exacerbated by the lack of local and independent control of the post-Acquisition ALLETE Board. The ALLETE Board would approve Minnesota Power's business plans and budgets and

[117] Cady Direct at 13:6-9.

would be largely controlled by the Partners. The transition to a private company will also reduce the current level of transparency required by SEC reporting standards, regulators with less access into investment decisions. In addition, the Partners provide no commitment in the Merger Agreement to adhere to Minnesota Power's coal retirement schedule, and if ALLETE is sold again in the future, there is no guarantee that future owners would follow through on current plans to retire Minnesota Power's coal fleet.

In light of the potential harms of the proposed Acquisition, without any commitment to ratepayer benefits, I conclude that the transaction is not in the public interest. I therefore recommend that the Commission not approve the Acquisition.

Q Does this conclude your direct testimony?

A Yes, it does.

ATTACHMENT CL-1

Courtney Lane Resume

Courtney Lane, Senior Principal

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clane@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Principal*, August 2024 – Present, *Principal Associate*, September 2022 – August 2024, *Senior Associate,* November 2019 – September 2022.

Provides consulting and researching services on a wide range of issues related to the electric industry including performance-based regulation, benefit-cost assessment, rate and bill impacts, and assessment of distributed energy resource policies and programs. Develops expert witness testimony in public utility commission proceedings.

National Grid, Waltham, MA. *Growth Management Lead*, *New England,* May 2019 – November 2019, *Lead Analyst for Rhode Island Policy and Evaluation,* June 2013 – April 2019.

- Portfolio management of product verticals including energy efficiency, demand response, solar, storage, distributed gas resources, and electric transportation, to optimize growth and customer offerings.
- Strategy lead for the Performance Incentive Mechanisms (PIMs) working group.
- Worked with internal and external stakeholders and led the development of National Grid's Annual and Three-Year Energy Efficiency Plans and System Reliability Procurement Plans for the state of Rhode Island.
- Represented energy efficiency and demand response within the company at various Rhode Island grid modernization proceedings.
- Led the Rhode Island Energy Efficiency Collaborative; a group focused on reaching consensuses regarding energy efficiency plans and policy issues for demand-side resources in Rhode Island.
- Managed evaluations of National Grid's residential energy efficiency programs in Rhode Island, and benefit-cost models to screen energy efficiency measures.

Citizens for Pennsylvania's Future, Philadelphia, PA. *Senior Energy Policy Analyst*, 2005–2013.

- Played a vital role in several legislative victories in Pennsylvania, including passage of energy conservation legislation that requires utilities to reduce overall and peak demand for electricity (2009); passage of the $650 million Alternative Energy Investment Act (2008); and important amendments to the Alternative Energy Portfolio Standards law vital to the development of solar energy in Pennsylvania (2007).
- Performed market research and industry investigation on emerging energy resources including wind, solar, energy efficiency and demand response.
- Planned, facilitated and participated in wind energy advocates training meetings, annual partners retreat with members of wind and solar companies, and the PennFuture annual clean energy conference.

Northeast Energy Efficiency Partnerships, Inc., Lexington, MA. *Research and Policy Analyst,* 2004–2005.

- Drafted comments and testimony on various state regulatory and legislative actions pertaining to energy efficiency.
- Tracked energy efficiency initiatives set forth in various state climate change action plans, and federal and state energy regulatory developments and requirements.
- Participated in Regional Greenhouse Gas Initiative (RGGI) stakeholder meetings.
- Analyzed cost-effectiveness of various initiatives within the organization.

EnviroBusiness, Inc., Cambridge, MA. *Environmental Scientist,* July 2000 – May 2001

- Conducted pre-acquisition assessments/due diligence assignments for properties throughout New England. Environmental assessments included an analysis of historic properties, wetlands, endangered species habitat, floodplains, and other areas of environmental concern and the possible impacts of cellular installations on these sensitive areas.

EDUCATION

Tufts University, Medford, MA
Master of Arts; Environmental Policy and Planning, 2004.

Colgate University, Hamilton, NY
Bachelor of Arts; Environmental Geography, 2000, *cum laude.*

PUBLICATIONS

Fortman, N., J. Michals, T. Woolf, C. Lane. 2022. *Benefit-Cost Analysis: What it Can and Cannot Tell us About Distributional Equity of DERs*. E4TheFuture, Synapse Energy Economics. Presented at the 2022 ACEEE Summer Study of Energy Efficiency in Buildings.

National Energy Screening Project. 2022. *Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis*. E4TheFuture, Synapse Energy Economics, Parmenter Consulting, Apex Analytics, Energy Futures Group.

Woolf, T., D Bhandari, C. Lane, J. Frost, B. Havumaki, S. Letendre, C. Odom. 2021. *Benefit-Cost Analysis of the Rhode Island Community Remote Net Metering Program*. Synapse Energy Economics for the Rhode Island Division of Public Utilities and Carriers.

Lane, C., S. Kwok, J. Hall, I. Addleton. 2021. *Macroeconomic Analysis of Clean Vehicle Policy Scenarios for Illinois*. Synapse Energy for the Natural Resources Defense Council.

National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. E4TheFuture, Synapse Energy Economics, Energy Futures Group, ICF, Pace Energy and Climate Center, Schiller Consulting, Smart Electric Power Alliance.

Lane, C., K. Takahashi. 2020. *Rate and Bill Impact Analysis of Rhode Island Natural Gas Energy Efficiency Programs.* Synapse Energy Economics for National Grid.

Chang, M., J. Frost, C. Lane, S. Letendre, PhD. 2020. *The Fixed Resource Requirement Alternative to PJM's Capacity Market: A Guide for State Decision-Making*. Synapse Energy Economics for the State Energy & Environmental Impact Center at the NYU School of Law.

TESTIMONY

New Mexico Public Regulation Commission (Case No. 22-00058-UT): Supplemental Testimony of Courtney Lane regarding the Benefit Cost Analysis of Public Service Company of New Mexico's grid modernization application. On behalf of the New Mexico Office of Attorney General. March 1, 2024.

Public Service Commission of the District of Columbia (Formal Case No. 1176): Direct and Surrebuttal Testimony of Courtney Lane regarding the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia. On behalf of the District of Columbia Government. January 12, 2024 and April 22, 2024.

Maryland Public Service Commission (Case No. 9702): Direct and Surrebuttal Testimony of Courtney Lane regarding electric vehicle programs and cost recovery issues in the application of Potomac Electric Power Company for an Electric Multi-Year Plan. On behalf of the Maryland Office of People's Counsel. December 15, 2023 and February 23, 2024.

Public Utilities Commission of New Hampshire (Docket No. DE 23-039): Direct Testimony of Courtney Lane regarding Liberty Utilities Request for Change in Distribution Rates. On behalf of the Office of Consumer Advocate. December 13, 2023.

Maryland Public Service Commission (Case No. 9696): Direct Testimony of Courtney Lane regarding the application of Baltimore Gas and Electric Company for an Electric School Bus Pilot Program. On behalf of the Maryland Office of People's Counsel. July 25, 2023.

Maryland Public Service Commission (Case No. 9695): Direct and Surrebuttal Testimony of Courtney Lane regarding electric vehicle program benefit-cost analysis issues in the application of the Potomac Edison Company for Adjustments to its Electric Retail Rates. On behalf of the Maryland Office of People's Counsel. June 9, 2023 and July 14, 2023.

Maryland Public Service Commission (Case No. 9692): Direct and Surrebuttal Testimony of Courtney Lane regarding electric vehicle program benefit-cost analysis issues in the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People's Counsel. June 20, 2023 and August 25, 2023.

California Public Utilities Commission (Application Nos. 22-05-015/22-05-01): Prepared Testimony of Eric Borden and Coutney Lane regarding Quantitative Risk Analysis Issues in Sempra's 2024 Test Year General Rate Case. On behalf of The Utility Reform Network. March 27, 2023.

New Mexico Public Regulation Commission (Case No. 22-00058-UT): Direct Testimony of Courtney Lane regarding the application of Public Service Company of New Mexico's for authorization to implement grid modernization. On behalf of the New Mexico Office of Attorney General. January 27, 2023.

Illinois Commerce Commission (Dockets 22-0432/22-0442 (Consol.): Direct and Rebuttal Testimony of Courtney Lane and Eric Borden regarding the petition of Commonwealth Edison Company for Approval of Beneficial Electrification Plan Under the Electric Vehicle Act. On behalf of the People of the State of Illinois. September 22, 2022 and November 16, 2022.

Illinois Commerce Commission (Docket No. 22-0431/22-0443): Direct and Rebuttal Testimony of Courtney Lane and Eric Borden regarding the petition of Ameren Illinois Company for Approval of Beneficial Electrification Pursuant to Section 45 of the Electric Vehicle Act. On behalf of the People of the State of Illinois. September 15, 2022 and November 7, 2022.

New Mexico Public Regulation Commission (Case No. 21-00178-UT): Direct Testimony of Courtney Lane regarding the application of Southwestern Public Service Company's for authorization to implement grid modernization. On behalf of the New Mexico Office of Attorney General. October 11, 2022.

Public Service Commission of Wisconsin (Docket 5-UR-110): Direct and Surrebuttal Testimony of Courtney Lane regarding the Joint Application of Wisconsin Electric Power Company and Wisconsin Gas, LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates. On behalf of Clean Wisconsin. September 9, 2022 and October 3, 2022.

Maryland Public Service Commission (Case No. 9681): Direct Testimony of Courtney Lane regarding the application of Delmarva Power & Light Company for an Electric Multi-Year Plan. On behalf of the Maryland Office of People's Counsel. August 19, 2022.

New Mexico Public Regulation Commission (Case No. 21-00269-UT): Testimony of Courtney Lane in Support of Unopposed Comprehensive Stipulation regarding the Application of El Paso Electric Company for Approval of a Grid Modernization Project to Implement an Advanced Metering System. On behalf of the New Mexico Office of Attorney General. May 11, 2022.

Public Utilities Commission of New Hampshire (Docket No. DG 21-104): Direct Testimony of Courtney Lane and Ben Havumaki regarding Northern Utilities, Inc.'s request for change in rates. On behalf of the Office of Consumer Advocate. April 1, 2022.

Public Utilities Commission of New Hampshire (Docket No. DE 20-092): Direct Testimony of Courtney Lane and Danielle Goldberg regarding the 2021-2023 Triennial Energy Efficiency Plan. On behalf of the Office of Consumer Advocate. April 19, 2022.

Maryland Public Service Commission (Case No. 9655): Direct and Surrebuttal Testimony of Courtney Lane regarding the application of Potomac Electric Company for a Multi-Year Plan and Performance Incentive Mechanisms. On behalf of the Maryland Office of People's Counsel. March 3, 2021 and April 20, 2021.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020830): Direct testimony of Alice Napoleon and Courtney Lane regarding PECO Energy Company's proposed Act 129 Phase IV Energy Efficiency and Conservation Plan. On behalf of the Natural Resources Defense Council. January 14, 2021.

Maryland Public Service Commission (Case No. 9645): Direct and Surrebuttal Testimony of Courtney Lane regarding the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People's Counsel. August 14, 2020 and October 7, 2020.

Maryland Public Service Commission (Case No. 9619): Comments of Maryland Office of People's Counsel Regarding Energy Storage Pilot Program Applications, attached Synapse Energy Economics Report. June 23, 2020.

Public Service Commission of the District of Columbia (Formal Case No. 1156): Direct, Rebuttal, Surrebuttal, and Supplemental Testimony of Courtney Lane regarding the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia. On behalf of the District of Columbia Government. March 6, 2020, April 8, 2020, June 1, 2020, and July 27, 2020.

Rhode Island Public Utilities Commission (Docket No. 4888): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 Energy Efficiency Program (EEP). On behalf of National Grid. December 11, 2018.

Rhode Island Public Utilities Commission (Docket No. 4889): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 System Reliability Procurement Report (SRP). On behalf of National Grid. December 10, 2018.

Rhode Island Public Utilities Commission (Docket No. 4755): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2018 Energy Efficiency Program (EEP). On behalf of National Grid. December 13, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding the RI Energy Efficiency and Resource Management Council (EERMC) Proposed Energy Efficiency Savings Targets for National Grid's Energy Efficiency and System Reliability Procurement for the Period 2018-2020 Pursuant to §39-1-27.7. On behalf of National Grid. March 7, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding National Grid's 2018-2020 Energy Efficiency and System Reliability Procurement Plan. On behalf of National Grid. October 25, 2017.

Rhode Island Public Utilities Commission (Docket No. 4654): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2017 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 8, 2016.

Rhode Island Public Utilities Commission (Docket No. 4580): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2016 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 2, 2015.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320369): Direct testimony of Courtney Lane regarding the Petition of PPL Electric Utilities Corporation for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. October 19, 2012.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320334): Direct testimony of Courtney Lane regarding the Petition of PECO Energy for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. September 20, 2012.

Pennsylvania Public Utility Commission (Docket No. I-2011-2237952): Oral testimony of Courtney Lane regarding the Commission's Investigation of Pennsylvania's Retail Electricity Markets. On behalf of PennFuture. March 21, 2012.

Committee on the Environment Council of the City of Philadelphia (Bill No. 110829): Oral testimony of Courtney Lane regarding building permitting fees for solar energy projects. On behalf of PennFuture. December 5, 2011.

Pennsylvania Public Utility Commission (Docket No. M-00061984): Oral testimony of Courtney Lane regarding the En Banc Hearing on Alternative Energy, Energy Conservation, and Demand Side Response. On behalf of PennFuture. November 19, 2008.

PRESENTATIONS

Lane, C. 2021. "Accounting for Interactive Effects: Assessing the Cost-Effectiveness of Integrated Distributed Energy Resources." Presentation at the 2021 American Council for an Energy-Efficient Economy (ACEEE) National Conference on Energy Efficiency as a Resource, October 27, 2021.

Lane, C. 2019. "The RI Test." Presentation for AESP Webinar: Emerging Valuation Approaches in Cost-Effectiveness and IRPs, October 31, 2019.

Lane, C., A. Flanders. 2017. "National Grid Rhode Island: Piloting Wireless Alternatives: Forging a Successful Program in Difficult Circumstances." Presentation at the 35th Annual Peak Load Management Association (PLMA) Conference, Nashville, TN, April 4, 2017.

Lane, C. 2013. "Regional Renewable Energy Policy Update." Presentation at the Globalcon Conference, Philadelphia, PA, March 6, 2013.

Lane, C. 2012. "Act 129 and Beyond." Presentation at the ACI Mid-Atlantic Home Performance Conference, October 1, 2012.

Lane, C. 2012. “Act 129: Taking Energy Efficiency to the Next Level.” Presentation at the Energypath Conference, June 28, 2012.

Lane, C. 2011. “Pennsylvania’s Model Wind Ordinance.” Presentation at Harvesting Wind Energy on the Delmarva Peninsula, September 14, 2011.

Lane, C. 2011. “Electric Retail Competition and the AEPS.” Presentation at the Villanova Law Forum, November 4, 2011.

Lane, C. 2009. “Act 129: Growing the Energy Conservation Market.” Presentation at the Western Chester County Chamber of Commerce, March 25, 2009.

Resume updated July 2024.

ATTACHMENT CL-2

Petitioners' Public Responses to Information Requests

Petitioners' Response to SC IR 8

Petitioners' Response to SC IR 15

Petitioners' Response to SC IR 20

Petitioners' Response to SC IR 25

Petitioners' Response to SC IR 35

Petitioners' Response to SC IR 41

Petitioners' Response to SC IR 69

Petitioners' Response to CUB IR 39

Petitioners' Response to CUB IR 59

Petitioners' Response to CUB IR 106

Petitioners' Response to CUB IR 122

Petitioners' Response to CUB IR 123

Petitioners' Response to CUB IR 130

Petitioners' Response to DOC IR 43

Petitioners' Response to DOC IR 81

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 8

Date of Request: December 23, 2024

Requested By: Sierra Club

Requested From: Minnesota Power

Request Due: January 7, 2025

Request:

Refer to the Direct Testimony of Jennifer Cady at page 13, lines 6-9, which states that "the Acquisition will provide Minnesota Power and, thus, its customers access to capital that will allow for compliance with the Minnesota Carbon Free Standard and accelerated renewable energy standard under Minn. Stat. § 216B.1691."

a. Will Minnesota Power accelerate its compliance with the Minnesota Carbon Free Standard compared to its current IRP due to the ability to access capital from the Partners (CPP Investments and Global Infrastructure Partners)? If yes, please list all the capital investment that Minnesota Power will accelerate and indicate the change in the timing of each investment. If not, please explain why not.

b. How will the Partners ensure alignment with Minnesota's IRP processes and clean energy goals?

Witness: Jennifer Cady	Witness: Jonathan Bram	Witness: Andrew Alley
Response Date: 01/07/2025	Response Date: 01/07/2025	Response Date: 01/07/2025
Response by: Jennifer Cady	Response by: GIP	Response by: CPP Investments
Email Address: jjcady@mnpower.com	Email Address: discoverymanager@mnpower.com	Email Address: discoverymanager@mnpower.com
Phone Number: 218-355-3202	Phone Number: n/a	Phone Number: n/a

c. What specific investments will the Partners commit to in order to meet Minnesota's 2040 Carbon-Free Standard?

d. Will the Partners commit to maintaining or expanding current funding levels for energy efficiency programs?

e. Will the proposed Acquisition enable Minnesota Power to decommission coal generation at Boswell Energy Center earlier than is currently planned? If yes, please explain. If not, please explain why not.

Response:

a. All resource planning for the Company's proposed path to compliance with Minnesota's 2040 Carbon Free Standard will be addressed through the Integrated Resource Plan ("IRP") process, with the Company's next IRP to be filed March 3, 2025.

b. Please see Section IV of the Direct Testimony of GIP Witness Bram and Section III of the Direct Testimony of CPP Investments Witness Alley.

c. Please see subpart (b), above.

d. Please see Section III of the Petition and Section IV of the Direct Testimony of Company Witness Cady for the Company's and Partners' commitment to maintain the overall scope and resources dedicated to affordability programs, which may include energy efficiency programs. Funding levels and program requirements for energy efficiency will continue to be regulated and set by the Department of Commerce and Commission.

e. Please see the response to SIERRA CLUB IR 0025.

Witness: Jennifer Cady	Witness: Jonathan Bram	Witness: Andrew Alley
Response Date: 01/07/2025	Response Date: 01/07/2025	Response Date: 01/07/2025
Response by: Jennifer Cady	Response by: GIP	Response by: CPP Investments
Email Address: jjcady@mnpower.com	Email Address: discoverymanager@mnpower.com	Email Address: discoverymanager@mnpower.com
Phone Number: 218-355-3202	Phone Number: n/a	Phone Number: n/a

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 15

Date of Request:	December 23, 2024
Requested By:	Sierra Club
Requested From:	Minnesota Power
Request Due:	January 7, 2025

Request:

Please refer to the Direct Testimony of Jonathan Bram at page 16, lines 3-7 and respond to the following questions regarding the entity that is identified as "Global Infrastructure GP V, L.P.":

a. How often would the general partner interact with ALLETE?

b. How would the general partner interact with the Board?

c. Please provide an example of a decision made by the general partner which could influence the decision making of Minnesota Power personnel.

Response:

(a) - (c) The general partner is the entity that controls the fund (i.e., the limited partnership) and it is through the general partner that the investment committee makes decisions about the fund's operations and investment decisions, as discussed in the responses to DOC IR 0004 and DOC IR

0005. As such, the general partner will not directly interact with ALLETE.

Please also refer to CUB IR 0078. The general partner will make decisions on behalf of the fund, but day-to-day operations of Minnesota Power will be conducted by the same individuals operating the businesses prior to the Acquisition and under the same regulatory oversight.

The phrase “a decision made by the general partner which could influence the decision making of Minnesota Power personnel” is vague, and it is not possible to speculate as to all factors that influence Minnesota Power personnel, including management. Nevertheless, the general partner will make decisions on behalf of GIP Fund V, but day-to-day operations of Minnesota Power will be conducted by the same individuals (Minnesota Power personnel) operating the business prior to the Acquisition and ALLETE will continue to have a Board of Directors and ALLETE will remain under the same regulatory oversight. Please also refer to CUB IR 0078.

Further, upon closing of the Acquisition, GIP and CPP Investments will appoint directors who will hold customary board responsibilities, including budgetary approvals, capital issuances, acquisitions and divestitures, and fundamental changes and actions consistent with customary board obligations, to jointly govern ALLETE through the exercise of consent rights.

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 20

Date of Request:	December 23, 2024
Requested By:	Sierra Club
Requested From:	Minnesota Power
Request Due:	January 7, 2025

Request:

Refer to the Direct Testimony of Jonathan Bram at page 12, lines 14-15, which states, "GIP will provide this support to the Company through the appointment of experienced, professional board members who will cooperate with other board members and the current Company management" and also refer to Jonathan Bram's Direct Testimony at page 21 related to the ALLETE Board.

a. State with specificity the standards, principles or tests that should be applied to determine if a member is "independent."

b. What percentage of the ALLETE Board will be "independent" and how will that percentage change over the next five years?

c. Will the "independent" Directors have a quorum?

d. Will GIP commit to having both "independent" Directors reside in Minnesota? Why or why not?

e. Will the ALLETE Board have authority over budgets, operations, and/or decision of future operations of Minnesota Power?

Witness: n/a Response Date: n/a Response by: n/a Email Address: n/a Phone Number: n/a	Witness: Jonathan Bram Response Date: 01/07/2025 Response by: GIP Email Address: discoverymanager@mnpower.com Phone Number: n/a	Witness: n/a Response Date: n/a Response by: n/a Email Address: n/a Phone Number: n/a

f. With respect to the post-Acquisition ALLETE Board as presently envisioned by GIP, identify and provide each document that discusses, analyzes or otherwise addresses:

   i. the selection process;

   ii. who would be a member;

   iii. what interests would be represented on the Board.

Response:

(a) Refer to SIERRA CLUB IR 0041(a).

(b) Neither the members of the ALLETE Board following the Acquisition nor any process for changing the numbers of board members has been determined. As referenced in the Petition at Page 11-12, upon closing of the Acquisition, the ALLETE Board will include: (a) at least one member from Minnesota, (b) at least one member from Wisconsin, (c) at least two independent directors and (d) the chief executive officer of ALLETE.

(c) Refer to (b) above. Membership of the ALLETE board has not yet been determined but it is not anticipated that independent directors would have a quorum on the ALLETE board.

(d) Refer to (b) above. Superior Water, Light & Power, a [Wisconsin utility], is a subsidiary of ALLETE, and independent Board membership from Wisconsin is a consideration.

(e) Board authority is discussed in Section IV of the Direct Testimony of Company Witness Scissons.

(f) Refer to (b) above.

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 25

Date of Request:	December 23, 2024
Requested By:	Sierra Club
Requested From:	Minnesota Power
Request Due:	January 7, 2025

Request:

Refer to the Direct Testimony of Joshua D. Taran, at page 5, lines 10-19 that discusses Minnesota Power's anticipated transition away from coal generation at Boswell Energy Center.

a. Without approval of the proposed Acquisition, in what year does Minnesota Power plan to decommission the Boswell Energy Center?

b. If the proposed Acquisition is approved, in what year does Minnesota Power plan to decommission the Boswell Energy Center?

Response:

(a-b) As of this response, and consistent with the Company's Commission-approved Integrated Resource Plan (Docket No. E015/RP-21-33) ("IRP"), the Company intends to cease coal generation at Boswell Energy Center Unit 3 by December 31, 2029, and at Boswell Energy Center Unit 4 by 2035.

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 35

Date of Request: December 23, 2024

Requested By: Sierra Club

Requested From: Minnesota Power

Request Due:

January 7, 2025

Request:

Refer to the Direct Testimony of Jeffery J. Scissons at page 11, lines 1 – 21.

a. Please provide a list of strategic plans which have been submitted to the Board for approval over the past 10 years. Please state if these plans were approved, not approved, or approved with modifications.

b. For those strategic plans which have not been approved by the Board, please summarize the reason for not approving the plans.

c. Are strategic plans developed with their potential approval in mind? Please include an explanation of how Board approval compares to the other priorities influencing the strategic plan.

d. If few strategic plans have been rejected by the Board, would it be fair to characterize that the strategic plans were developed with Board approval in mind?

Witness: Jeff Scissons	Witness: n/a	Witness: n/a
Response Date: 01/07/2025	Response Date: n/a	Response Date: n/a
Response by: Tara Anderson	Response by: n/a	Response by: n/a
Email Address: tlanderson@allete.com	Email Address: n/a	Email Address: n/a
Phone Number: 218-355-3470	Phone Number: n/a	Phone Number: n/a

If that is not a fair characterization, please explain why not.

e. If strategic plans are developed with Board approval in mind, please describe why the composition of the Board would not influence the development of the strategic plans.

f. Given that "the Partners' role post-Acquisition would be similar to that of the current ALLETE Board," and that strategic plans are developed with Board approval in mind, please describe why the change in equity ownership would not change the strategic plans developed by Minnesota Power personnel.

Response:

Minnesota Power and the Partners object to subpart (a) to the extent that it seeks information that is not relevant and/or not proportional to the needs of the case and is overly broad and unduly burdensome.

Subject to and without waiving the foregoing objections, Minnesota Power and the Partners respond as follows:

a–d. ALLETE's strategy is not a singular document. The Company's strategy is iterative, born out of its unique connection to the customers and communities it serves, and is continually adjusted to reflect current considerations. Additionally, Company strategy comes from and represents every aspect of operating a business, including operations, safety, employee recruitment and retention, compensation and benefits, financial discipline, etc. It is not formally "approved" or "rejected" by the Board, and therefore strategies are not developed for approval or rejection by the Board. Rather, the Board will ask questions and provide insights and expertise to support decisions affecting the strategic direction of the Company. The Board ultimately approves the Company's budget, which is what allows it to effectuate strategy.

e.-f. Please see the response to subparts a-d with respect to Board approval. As discussed in Company responses to other information requests (Please see CUB IRs 0029, 0039 and 0163), the Partners are acquiring ALLETE to invest in the existing strategy and have committed to maintaining current management to execute on that strategy. A change in ownership will not change the direction of the strategic plan because the Partners are aligned with ALLETE's strategy. While there will be a new ALLETE Board that will bring their unique expertise to support the continued execution of ALLETE's strategy, it is important to note that the Commission retains authority to approve and provide oversight of Minnesota Power's service to customers, resource plans, distribution plans, customer programs and services, customer rates, and more.

Witness: Jeff Scissons	Witness: n/a	Witness: n/a
Response Date: 01/07/2025	Response Date: n/a	Response Date: n/a
Response by: Tara Anderson	Response by: n/a	Response by: n/a
Email Address: tlanderson@allete.com	Email Address: n/a	Email Address: n/a
Phone Number: 218-355-3470	Phone Number: n/a	Phone Number: n/a

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's First Set of Information Requests to Minnesota Power: Information Request No. 41

Date of Request: December 23, 2024

Requested By: Sierra Club

Requested From: Minnesota Power

Request Due: January 7, 2025

Request:

Refer generally to the discussion of the Partners appointment of Board members on page 18 of the Direct Testimony of Andew Alley.

a) State with specificity the standards, principles or tests that should be applied to determine if a member is "independent."

b) What percentage of the ALLETE Board will be "independent" and how will that percentage change over the next five years?

c) Will the "independent" Directors have a quorum?

d) Will CPP Investments commit to having both" independent" Directors reside in Minnesota? Why or why not?

e) Please indicate if the ALLETE Board will have authority over budgets, operations, and/or decision of future operations of the Minnesota Power.

Witness: Jeff Scissons	Witness: n/a	Witness: Andrew Alley
Response Date: 01/07/2025	Response Date: n/a	Response Date: 01/07/2025
Response by: n/a	Response by: n/a	Response by: CPP Investments
Email Address: jscissons@allete.com	Email Address: n/a	Email Address: discoverymanager@mnpower.com
Phone Number: 218-355-3062	Phone Number: n/a	Phone Number: n/a

Response:

(a) *CPP Investments objects to this request to the extent that it calls for legal analysis and/or legal conclusions.*
Subject to and without waiving the foregoing objections, please see the following response:

Specific to this Acquisition, the Partners intend that "independent directors," as described in the Merger Agreement and the Petition, refer to directors who are not employees or officers of ALLETE or the Partners.

(b) Neither the members of the ALLETE Board following the Acquisition nor any process for changing the numbers of board members has been determined. As referenced in the Petition at Page 11-12, upon closing of the Acquisition, the ALLETE Board will include at minimum: (a) at least one member from Minnesota, (b) at least one member from Wisconsin, (c) at least two independent directors and (d) the chief executive officer of ALLETE.

(c) Refer to (b) above. Membership of the ALLETE board has not yet been determined but it is not anticipated that independent directors would have a quorum on the ALLETE board.

(d) Refer to (b) above. CPP Investments notes that Superior Water, Light & Power, a Wisconsin utility, is a subsidiary of ALLETE, and independent Board membership from Wisconsin is a consideration.

(e) Board authority is discussed in Section IV of the Direct Testimony of Company Witness Scissons. Refer also to SIERRA CLUB IR 0035.

(f) Refer to (b) above.

Witness: Jeff Scissons	Witness: n/a	Witness: Andrew Alley
Response Date: 01/07/2025	Response Date: n/a	Response Date: 01/07/2025
Response by: n/a	Response by: n/a	Response by: CPP Investments
Email Address: jscissons@allete.com	Email Address: n/a	Email Address: discoverymanager@mnpower.com
Phone Number: 218-355-3062	Phone Number: n/a	Phone Number: n/a

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	OAH Docket No. 25-2500-40339 MPUC Docket No. E015/PA-24-198

Sierra Club's 4th Set of Information Requests to Minnesota Power, Canada Pension Plan Investment Board, Global Infrastructure Partners: Request No. 69

Date of Request:	January 17, 2025
Requested By:	Sierra Club
Requested From:	Minnesota Power/ALLETE, Canada Pension Plan Investment Board, Global Infrastructure Partners
Request Due:	January 27, 2025

Request:

Refer to the response to CUB IR 0123(b) which states that "CPP Investments has an investment-only mandate and will not be involved in the day-to-day operation of the Minnesota Power utility"

a. Please define "day-to-day operation" and provide specific examples.

b. What guides MN Power's day-to-day operations? For example, are there strategic plans, Key Performance Indicators that guide these operations?

c. Please explain how the ALLETE board currently informs decisions that impact Minnesota Power's day-to day operations.

d. What documents and policies inform Minnesota Power's "day-to-day decision-making"?

e. Does Minnesota Power have a strategic plan, business plan, or company policy that informs its day-to-day operations? If yes, please explain how those plans or policies inform Minnesota Power's day-to-day operations.

f. Does the ALLETE Board of Directors have any involvement in the development of the plans and policies included in your response to (d) and (e) above that informs Minnesota Power's day-to-day operations? Please explain. If your response cites a supplemental filing, testimony, or the Petition, please provide the relevant page number(s) and line(s) that answer the question.

Response:

a. "Day-to-day operations" in this context refers to the daily operational decisions made by Minnesota Power personnel that build, operate and maintain transmission and distribution systems and generation facilities, provide engineering services, deliver customer services, provide support services, etc.
b. There are numerous possible interpretations of what "guides" may mean as used in this question. In general, Minnesota Power's day-to-day operations are guided by state and federal regulations, the MPUC, numerous regulatory permits, customer agreements, operating budgets, internal company policies, and by the direction of Minnesota Power's officers and senior managers and governance of the ALLETE Board of Directors.
c. The ALLETE Board of Directors has final approval of operational budgets and engages on strategic planning Please see the response to SIERRA IR 0035.
d. See the response to part(b).
e. Please see the response to SIERRA IR 0035.
f. Please see the response to SIERRA IR 0035.

Witness: Josh Skelton	Witness: n/a	Witness: n/a
Response Date: 01/30/2025	Response Date: n/a	Response Date: n/a
Response by: Rhonda Munger	Response by: n/a	Response by: n/a
Email Address: rmunger@mnpower.com	Email Address: n/a	Email Address: n/a
Phone Number: 218-313-4496	Phone Number: n/a	Phone Number: n/a

Citizens Utility Board of Minnesota

Information Requests 0039

Date of Request:	October 4, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	October 18, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners **Docket No. E-015/PA-24-198**

Request:

For all benefits that you assert will come from this transaction, explain why those benefits would not be available without the transaction.

Response:

It is Minnesota Power's typical practice to avoid stating formal legal objections and/or standing on those objections to discovery in Minnesota regulatory proceedings, to the extent practicable, to facilitate a cooperative and productive process. However, many of the questions and stated premises, as well as the argumentative tone, in this set of information requests from CUB's external witness (CUB IRs 1-72) are outside typical discovery practices in the Minnesota regulatory process, and therefore necessarily affect the Company's and Partners' responses.

In addition, consistent with Minnesota practice, the party(ies) and witness(es) responding to this discovery request are denoted by the witness information in the footer of this response.

The primary benefit of the transaction, as stated in the July 19, 2024 Petition, is that the Company will be able to access capital from highly experienced partners that bring deep industry expertise and share the Company's values, thereby allowing Minnesota Power to obtain the significant additional capital it needs for energy transition-related investments in renewable energy, carbon reduction, grid resiliency and reliability, and clean energy enabling technologies in the years ahead. Private investors such as the Partners have an ability not only to provide the required capital and do so on a more readily available basis, but also provide capital with the ability to exercise more patience with respect to quarterly earnings and dividends due to a focus on long-term investments. Additionally, such capital can be raised based on the Partners' clear understanding of the Company's goals and investments and recognition of the need for capital, rather than having to work though the public markets.

Recognizing that ALLETE is a relatively small energy company seeking significant financing in the public markets, without this transaction there is no guarantee that Minnesota Power would be able to access the capital it needs for clean energy transition investments outlined above. Further, the Company would continue to be exposed to the risks associated with volatility of the public markets. Finally, the quarter-to-quarter nature of the public markets is at direct odds with the patient capital private investors like the Partners bring with their long-term investment view.

In this way, the Company is making a choice with respect to its Partners that preserves the nature of ALLETE and its longstanding success in supporting customers. Further, this type of proposed acquisition will not change the role or diminish the existing regulatory authority of the Commission. Ultimately, the Minnesota Power utility is wholly unchanged in terms of its regulatory requirements, customer profile, system load, employee obligations, utility infrastructure and system needs, level of financing needs and alignment with State policy goals.

Witness: Jennifer Cady	Witness: n/a	Witness: n/a
Response Date: 10/21/2024	Response Date: n/a	Response Date: n/a
Response by: Jennifer Kuklenski	Response by: n/a	Response by: n/a
Email Address: jkuklenski@mnpower.com	Email Address: n/a	Email Address: n/a
Phone Number: 218-355-3297	Phone Number: n/a	Phone Number: n/a

Citizens Utility Board of Minnesota

Information Requests 0059

Date of Request:	October 4, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	October 18, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners	**Docket No. E-015/PA-24-198**

Request:

You state (Petition at 17): "Retaining and supporting ALLETE's current management team and employees, along with ALLETE's commitment to supporting low income and disadvantaged parts of the communities ALLETE serves, is critical to the Partners' commitment to the Acquisition." By this sentence, or by any other sentence in the Petition, are the Partners committing never to influence ALLETE Board decisions on who should be on Minnesota Power's "management team"?

Response:

It is Minnesota Power's typical practice to avoid stating formal legal objections and/or standing on those objections to discovery in Minnesota regulatory proceedings, to the extent practicable, to facilitate a cooperative and productive process. However, many of the questions and stated premises, as well as the argumentative tone, in this set of information requests from CUB's external witness (CUB IRs 1-72) are outside typical discovery practices in the Minnesota regulatory process, and therefore necessarily affect the Company's and Partners' responses.

In addition, consistent with Minnesota practice, the party(ies) and witness(es) responding to this discovery request are denoted by the witness information in the footer of this response.

The parties to the Acquisition cannot speculate regarding future management team decisions or other future situations of the ALLETE Board, but note the Partners have made numerous commitments as further described in the Petition and memorialized in the Merger Agreement. Please see the response to CUB IR 0041.

Citizens Utility Board of Minnesota

Information Requests 0106

Date of Request:	October 22, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	November 1, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners **Docket No. E-015/PA-24-198**

Request:

Confirm, or modify to make correct, these statements: (a) BlackRock owns or controls 10.81% of Cleveland Cliffs and 10.41% of U.S. Steel. (b) Each of Cleveland Cliffs and U.S. Steel is a customer of Minnesota Power. (c) The sum of Cleveland Cliffs's and U.S. Steel's electricity demand represents the majority—around 70%—of Minnesota Power's industrial demand. (See https://www.sec.gov/ix?doc=/Archives/edgar/data/66756/000006675624000007/ale-20231231.htm.) (d) GIP's CEO, Adebayo Ogunlesi, will join BlackRock's Board of Directors and global executive committee.

Response:

It is Minnesota Power's typical practice to avoid stating formal legal objections and/or standing on those objections to discovery in Minnesota regulatory proceedings, to the extent practicable, to facilitate a cooperative and productive process. However, many of the questions and stated premises, as well as the argumentative tone, in this set of information requests from CUB's external witness ***(CUB IRs 73-121)*** *are outside typical discovery practices in the Minnesota regulatory process, and therefore necessarily affect the Company's and Partners' responses.*

In addition, consistent with Minnesota practice, the party(ies) and witness(es) responding to this discovery request are denoted by the witness information in the footer of this response.

Minnesota Power and the Partners object to this request to the extent that it seeks information that is not relevant and/or not proportional to the needs of the case.

Subject to and without waiving the foregoing objections, please see the following response:

(a) Minnesota Power does not track this information. Minnesota Power and the Partners suggest that CUB review information filed by any of the identified companies to determine the percentages of shares owned by any particular company. For example, as shown on BlackRock's publicly available Form 13F filed with the SEC on August 13, 2024, as of June 30, 2024, BlackRock owned 10.99% of outstand shares of Cleveland Cliffs and 10.41% of U.S. Steel.

(b) Correct, Cleveland Cliffs and U.S. Steel are customers of Minnesota Power.

(c) Energy sales to taconite customers (of which Cleveland Cliffs and U.S. Steel are some of Minnesota Power's six taconite customers) represent approximately 70 percent of the energy sales to industrial customers, or approximately 50 percent of total energy sales to retail and municipal customers. (See https://www.sec.gov/ix?doc=/Archives/edgar/data/66756/000006675624000007/ale-20231231.htm.)

(d) GIP confirms this is consistent with its current expectations.

Witness: Josh Skelton	Witness: n/a	Witness: n/a
Response Date: 11/01/20204	Response Date: 11/01/2024	Response Date: 11/01/2024
Response by: Rhonda Munger	Response by: GIP	Response by: CPPIB
Email Address: rmunger@mnpower.com	Email Address: discoverymanager@mnpower.com	Email Address: discoverymanager@mnpower.com
Phone Number: 218-313-4496	Phone Number: n/a	Phone Number: n/a

Citizens Utility Board of Minnesota

Information Requests 122

Date of Request:	December 23, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	January 8, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners **Docket No. E-015/PA-24-198**

For the purposes of these requests, the "transaction" or "acquisition" refers to the transaction described in the petition dated July 19, 2024 and filed by the Petitioners in Minnesota Public Utilities Commission Docket No. E-015/PA-24-198. The "acquirers" refer collectively to Canada Pension Plan Investment Board, Global Infrastructure Management, LLC and subsidiaries or affiliates of either entity that will have direct or indirect ownership of ALLETE or Minnesota Power. "MN PUC" refers to the Minnesota Public Utilities Commission. Unless a response expressly indicates otherwise, we will assume each response submitted to these requests is attributable to the Petitioners collectively as joint signatories to the Petition. In any situation where any one or more of the Petitioners would respond to a request differently, please provide multiple responses, indicate who the responses should be attributed to, and explain the reasoning for Petitioners providing separate responses. For each response, please also identify the witness in this proceeding who will be responsible for covering the topic addressed by the question.

Where applicable, please provide your answers in a live, unlocked spreadsheet with all links and formulas intact. If the calculations or data origins are not obvious/labeled, provide a narrative explanation. Please send responses to the following email addresses: briane@cubminnesota.org; shempling@scotthemplinglaw.com. Any questions about the below requests should also be directed to briane@cubminnesota.org and shempling@scotthemplinglaw.com.

Request:

Reference Alley Direct at 10:27-29: CPP Investments bought Puget Sound Energy (Puget Energy or PSE) in 2009. You state, "In 2022, after many successful years and substantial benefits for both Puget Energy and CPP Investments, CPP Investments sold its share of Puget Energy to two other private investors pursuant to the approval of the [Washington Utilities and Transportation Commission [WUTC]."

(a) Identify all reasons, whether publicly stated or privately stated, for why CPP Investments sold its shares of PSE.

(b) Identify all conflicts between your decision to sell PSE and whatever forms of persuasion you used to persuade the WUTC to approve your acquisition of PSE.

(c) What commitments are you making to the Minnesota Public Utilities Commission (MN PUC or Commission) in terms of the number of years that you will own ALLETE shares?

(d) Identify all criteria you will use in deciding whether and when to sell your ALLETE shares.

(e) Identify all conflicts between those criteria and the public interest, as you define that phrase.

(f) Explain why it is in the public interest for the MN PUC to accept your arguments about your value to Minnesota Power as an owner when you intend to retain the discretion, subject to MN PUC approval, to depart as an owner.

(g) When you sell your shares to your replacement as ALLETE owner, to what extent will you compromise your goal of getting the best price in favor of the goal of selecting the owner who is best of Minnesota Power's customers? Does your charter permit you to accept an acquirer that is less favorable to your financial bottom line if that acquirer is a better fit for Minnesota Power's customers?

(h) With your answers to the foregoing questions, are you meaning to say that your interest in choosing the successor that is best for your bottom line is never in conflict with the interests of Minnesota Power's customers?

(i) Since you will have a right to seek PUC permission to sell your shares when it serves your interest, why shouldn't the PUC have a symmetrical right to direct you to sell your shares when your presence ceases to serve the customers' interest?

(j) Do you know whether the PUC already has that power (to direct CPP to sell your shares in ALLETE)?

Response:

CPP Investments object to subparts parts (e), (f), (i) and (j) to the extent they call for legal analysis and/or legal conclusions.

Subject to and without waiving the foregoing objection, CPP Investments responds as follows:

(a) After 13 years of partnership, CPP Investments saw limited future opportunities to deploy additional equity capital to support PSE's energy transition goals and felt it made sense to take an opportunity to sell its interest in PSE, which it ultimately did, and to pursue other opportunities to deploy capital on energy transition, infrastructure, renewable, and other long-term investments, like the investment in ALLETE.

(b) The terms "conflicts" and "forms of persuasion" are too vague to allow a meaningful response. See (a) above regarding CPP Investments' decision to sell its interest in PSE. See WUTC Docket No. U-210542 for further information regarding WUTC approval of CPP Investments' sale of its interest in PSE.

(c) CPP Investments does not have a pre-determined hold period or fund life for its infrastructure investments, which are long-term investments, and cannot speculate as to future events such as the specific number of years it will continue its investment in ALLETE. Any future sales that involve control of the regulated utility will need to be approved by the Minnesota Public Utilities Commission, which underscores the commitment of the Partners.

(d) It is not possible to provide a meaningful answer to the question without knowing the facts and circumstances that may arise at an undefined future point in time when it may decide to sell its interest in ALLETE, and CPP Investments cannot predict all the factors that could be involved in such a decision at that time.

(e) The term "conflicts" is too vague to allow a meaningful answer to the question. Further, see (d) above regarding any potential future decision to sell CPP Investments' interest in ALLETE.

(f) See the Petition at Section III for a discussion of the public interest benefits of the transaction. Any future sale of CPP Investments' interest in ALLETE would be subject to MPUC approval and the applicable public interest standard.

(g) The terms "compromise," "goal," "best price," or "best of Minnesota Power's customers" are too vague to allow a meaningful answer to this question. Further, see (d) above. A sale of CPP

Investments' interest in ALLETE will require Commission approval under the applicable public interest standard.

(h) The term "best for your bottom line" is too vague to allow a meaningful answer to this question. See (d) above regarding potential future sale of CPP Investments' interest in ALLETE. See (e) and (f) regarding application of the public interest standard to this transaction and to any future transaction.

(i) See objection. Notwithstanding that objection, the authority of the Minnesota Public Utilities Commission is established by Minnesota law.

(j) See objection.

Citizens Utility Board of Minnesota

Information Requests 123

Date of Request:	December 23, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	January 8, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners **Docket No. E-015/PA-24-198**

For the purposes of these requests, the "transaction" or "acquisition" refers to the transaction described in the petition dated July 19, 2024 and filed by the Petitioners in Minnesota Public Utilities Commission Docket No. E-015/PA-24-198. The "acquirers" refer collectively to Canada Pension Plan Investment Board, Global Infrastructure Management, LLC and subsidiaries or affiliates of either entity that will have direct or indirect ownership of ALLETE or Minnesota Power. "MN PUC" refers to the Minnesota Public Utilities Commission. Unless a response expressly indicates otherwise, we will assume each response submitted to these requests is attributable to the Petitioners collectively as joint signatories to the Petition. In any situation where any one or more of the Petitioners would respond to a request differently, please provide multiple responses, indicate who the responses should be attributed to, and explain the reasoning for Petitioners providing separate responses. For each response, please also identify the witness in this proceeding who will be responsible for covering the topic addressed by the question.

Where applicable, please provide your answers in a live, unlocked spreadsheet with all links and formulas intact. If the calculations or data origins are not obvious/labeled, provide a narrative explanation. Please send responses to the following email addresses: briane@cubminnesota.org; shempling@scotthemplinglaw.com. Any questions about the below requests should also be directed to briane@cubminnesota.org and shempling@scotthemplinglaw.com.

Request:

Reference Alley Direct at 14:1-7: You state that ALLETE's needs for capital to build infrastructure "presents an attractive opportunity for CPP Investments to make large investments in stable, well-managed infrastructure projects in a supportive regulatory environment."

(a) Acknowledge that if the MN PUC decides that customer cost will be lower if Minnesota Power buys renewable energy or transmission from third parties rather than build the infrastructure itself, CPP Investments will earn lower profit from its acquisition of ALLETE.

(b) Since you say that this acquisition is in the customers' interest, will you agree never to pressure ALLETE to prefer building needed infrastructure rather than buy power and transmission from third parties?

(c) Why did CPP Investments agree to pay a premium above the trading stock value? That is, what makes ownership more valuable to CPP Investments than it is to ordinary shareholders?

(d) How does CPP Investments believe it will recover the premium, and a return on it, given that ALLETE will not include the premium in Minnesota Power's rate base?

Response:

(a) The profitability of ALLETE and Minnesota Power depend on many factors and CPP Investments cannot speculate as to the results of this hypothetical question.

(b) As an initial matter, the questions in CUB IR 0123 make a number of assumptions that are not clearly established in or from the question itself or are based on faulty premises. As explained in the Petition and the Direct Testimony of Witness Alley, CPP Investments has an investment-only mandate and will not be involved in the day-to-day operation of the Minnesota Power utility. CPP Investments recognizes that the appropriate mix of generation and transmission resources for Minnesota Power will be approved by the Minnesota Public Utilities Commission.

(c) It is not clear what is meant by "ordinary" shareholders. Nevertheless, assuming that "ordinary shareholders" refers to public market shareholders, see the Direct Testimony of Witness Alley discussing CPP Investments' alignment with ALLETE and the benefits of the Acquisition. See also Attachment L of the Petition in the Background of the Merger section (page 44 of 239) and the responses to DOC IR 0015 and CUB IR 0073.

(d) As stated in the Direct Testimony of Witness Alley, CPP Investments' interests are aligned with the interests and needs of the Company. CPP Investments recognizes that while it would own the Company, the Company would retain the obligation to provide safe, reliable, and affordable electricity service to customers subject to Minnesota law and the regulatory requirements of the Commission and the policy goals of the State of Minnesota. The success of CPP Investment's investment will depend on the success of Minnesota Power consistent with these requirements.

Citizens Utility Board of Minnesota

Information Requests 130

Date of Request:	December 23, 2024
Requested By:	Brian Edstrom and Scott Hempling, on behalf of the Citizens Utility Board of Minnesota
Requested From:	ALLETE, Inc. D/B/A Minnesota Power; Canada Pension Plan Investment Board; Global Infrastructure Management, LLC (collectively, the "Petitioners")
Request Due:	January 8, 2024

In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners **Docket No. E-015/PA-24-198**

For the purposes of these requests, the "transaction" or "acquisition" refers to the transaction described in the petition dated July 19, 2024 and filed by the Petitioners in Minnesota Public Utilities Commission Docket No. E-015/PA-24-198. The "acquirers" refer collectively to Canada Pension Plan Investment Board, Global Infrastructure Management, LLC and subsidiaries or affiliates of either entity that will have direct or indirect ownership of ALLETE or Minnesota Power. "MN PUC" refers to the Minnesota Public Utilities Commission. Unless a response expressly indicates otherwise, we will assume each response submitted to these requests is attributable to the Petitioners collectively as joint signatories to the Petition. In any situation where any one or more of the Petitioners would respond to a request differently, please provide multiple responses, indicate who the responses should be attributed to, and explain the reasoning for Petitioners providing separate responses. For each response, please also identify the witness in this proceeding who will be responsible for covering the topic addressed by the question.

Where applicable, please provide your answers in a live, unlocked spreadsheet with all links and formulas intact. If the calculations or data origins are not obvious/labeled, provide a narrative explanation. Please send responses to the following email addresses: briane@cubminnesota.org; shempling@scotthemplinglaw.com. Any questions about the below requests should also be directed to briane@cubminnesota.org and shempling@scotthemplinglaw.com.

Request:

Reference Bram Direct at 7:13: "GIP's investment in ALLETE is intended to be a long-term investment."

(a) What is the number of years for which you are committing not to sell your shares in ALLETE?

(b) Since you will have a right to seek PUC permission to sell your shares when it serves your interest, why shouldn't the PUC have a symmetrical right to direct you to sell your shares when your presence ceases to serve the customers' interest?

(c) Do you know whether the PUC already has that power (to direct you to sell your shares in ALLETE)?

Response:

Minnesota Power and the Partners object to this request to the extent it calls for legal analysis and/or legal conclusions.

Subject to and without waiving the foregoing objection, Minnesota Power responds as follows:

(a) See the response to DOC IR 0009 regarding the operation of GIP Fund V. GIP has not otherwise made a determination regarding the specific length of time GIP will continue investments by GIP Fund V. Any future sales that involve control of the regulated utility will need to be approved by the Minnesota Public Utilities Commission, which establishes a significant commitment from the Partners.

(b) – (c) See objection. Notwithstanding the objection, the authority of the Minnesota Public Utilities Commission is based upon statute.

Witness: n/a	Witness: Jonathan Bram	Witness: n/a
Response Date: n/a	Response Date: 01/08/2025	Response Date: n/a
Response by: n/a	Response by: GIP	Response by: n/a
Email Address: n/a	Email Address: discoverymanager@mnpower.com	Email Address: n/a
Phone Number: n/a	Phone Number: n/a	Phone Number: n/a

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: 10/29/2024
Type of Inquiry: General Response Due: 11/8/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

To the extent that you produce documents in response to any request, clearly identify each document that is responsive to each request.

If the responding party does not have documents responsive to any request, please state that the responding party has conducted a diligent search and does not have responsive documents within its possession, custody or control.

Request Number:	**43**
Topic:	Transaction costs
Reference(s):	Merger Agreement, Section 6.06(b)(iii)(1), (2), (3)

Request:

(a) Please state the amount of acquisition premium to be paid in connection with the Acquisition and explain how that amount was determined. Provide all documents supporting this answer.

(b) Please provide an itemized list showing the amount and nature of any direct or indirect transaction costs incurred or expected to be incurred because of the Acquisition. Provide all documents supporting this answer.

(c) Please provide an itemized list showing the amount and nature of any transition costs incurred or expected to be incurred because of the Acquisition. Provide all documents supporting this answer.

Response:

(a) As explained in the Definitive Merger Proxy Statement that was included as Attachment L to the Petition, the $67 per share consideration payable to shareholders represents a premium of approximately 19 percent relative to the unaffected closing price for shares of ALLETE common stock on December 4, 2023 (the last trading day prior to the initial publication of market rumors regarding a potential acquisition of the Company)

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: 10/29/2024
Type of Inquiry: General Response Due: 11/8/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
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and a premium of approximately 22 percent over the 30-day volume weighted average price prior to that date. The consideration reflects a premium of approximately 10 percent relative to the closing price for shares of ALLETE common stock on May 2, 2024 (at market close prior to the publication of the May 2, 2024, market rumors regarding a potential acquisition of the Company). Individual shareholders' gain or loss is dependent on their purchase price. ALLETE stock has traded as high as $84 and as low as $48 over the last five years.

(b) Transaction costs incurred by ALLETE to date total $26.0 million through September 30, 2024, itemized as follows:

[TRADE SECRET BEGINS...

[redacted]

Witness: Colin Anderson	Witness: n/a	Witness: n/a
Response Date: 11/08/2024	Response Date: n/a	Response Date: n/a
Response by: Josh Rostollan	Response by: n/a	Response by: n/a
Email Address: jrostollan@allete.com	Email Address: n/a	Email Address: n/a
Phone Number: 218.355.3151	Phone Number: n/a	Phone Number: n/a

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: 10/29/2024
Type of Inquiry: General Response Due: 11/8/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

To the extent that you produce documents in response to any request, clearly identify each document that is responsive to each request.

If the responding party does not have documents responsive to any request, please state that the responding party has conducted a diligent search and does not have responsive documents within its possession, custody or control.

[redacted]

...TRADE SECRET ENDS]

The amount of future transaction costs is not known at this time, but the nature of those costs is expected to be similar to those incurred to date. As noted in the Petition, Minnesota Power is tracking these costs separately and will not attempt to recover these costs from its utility customers.
The information herein designated as trade secret includes transaction costs and has been designated as nonpublic because it contains information the Company considers to be trade secret information as defined by Minn. Stat. § 13.37, subd. 1(b). This information derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain value from its disclosure or use. Thus, the Company has made reasonable efforts to maintain its secrecy.

(c) Transition costs have not yet been incurred and the amount of transition costs expected to be incurred in the future is unknown. Transition costs would not be incurred until the Acquisition receives all regulatory approvals and closes. Transition costs, if any, are anticipated to primarily consist of internal employee labor and related overheads for employee time spent on transition activities. Such costs, if any, would be tracked to ensure they are not included in utility customer rate requests absent Commission approval. As stated in the Merger Agreement, the Company will not attempt to recover transition costs, if any, from its utility

Witness: Colin Anderson	Witness: n/a	Witness: n/a
Response Date: 11/08/2024	Response Date: n/a	Response Date: n/a
Response by: Josh Rostollan	Response by: n/a	Response by: n/a
Email Address: jrostollan@allete.com	Email Address: n/a	Email Address: n/a
Phone Number: 218.355.3151	Phone Number: n/a	Phone Number: n/a

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: 10/29/2024
Type of Inquiry: General Response Due: 11/8/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

To the extent that you produce documents in response to any request, clearly identify each document that is responsive to each request.

If the responding party does not have documents responsive to any request, please state that the responding party has conducted a diligent search and does not have responsive documents within its possession, custody or control.

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customers except to the extent the transition costs produce savings (and then only when and if savings materialize).

Witness: Colin Anderson	Witness: n/a	Witness: n/a
Response Date: 11/08/2024	Response Date: n/a	Response Date: n/a
Response by: Josh Rostollan	Response by: n/a	Response by: n/a
Email Address: jrostollan@allete.com	Email Address: n/a	Email Address: n/a
Phone Number: 218.355.3151	Phone Number: n/a	Phone Number: n/a

COMMERCE DEPARTMENT

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐ Nonpublic ☒ Public
Requested From: Global Infrastructure Partners Date of Request: 12/18/2024
Type of Inquiry: General Response Due: 12/26/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

Request Number:	**81**
Topic:	Partners' control of ALLETE
Reference(s):	Oct. 8, 2024 Supplemental Comments at 4

Request:

On page 4 of the Oct. 8 Supplemental Comments, the Company and the Partners stated, "GIP Fund V and Tower Bridge have a partial, indirect interest in Parent that provides GIP Fund V and Tower Bridge (along with CPP Investments) with certain decision-making authority over the ALLETE board of directors."

(a) Please fully describe and explain the decision-making authority GIP Fund V, Tower Bridge, and CPP Investments will have over the ALLETE board of directors.

(b) Please explain the limits of the ALLETE board of directors' power to make decisions that do not require approval by GIP Fund V, Tower Bridge, and CPP Investments.

(c) Please provide all governing documents, contracts, agreements, etc. that define the limits of the ALLETE board of directors' independent decision-making authority.

Response:

(a) As referenced in the Direct Testimony of Partner Witness Alley at page 17, Direct Testimony of Partner Witness Bram at page 21, and Direct Testimony of Company Witness Scissons at page 10, upon closing of the Acquisition, ALLETE will continue to have its own board of directors (the "ALLETE Board"). Additionally, as referenced in the Petition at page 8, upon closing of the Acquisition, the ALLETE Board will have fiduciary obligations and oversight responsibilities. Thus, when taking corporate action, the ALLETE Board members are not acting in their individual

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198
Requested From: Global Infrastructure Partners
Type of Inquiry: General

☐ Nonpublic ☒ Public
Date of Request: 12/18/2024
Response Due: 12/26/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

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capacity but instead acting in their capacity as a director on behalf of ALLETE. The members of the ALLETE Board following the Acquisition have not yet been determined but the ALLETE Board will have independent directors in addition to directors who are employees of GIP and CPP Investments. Additionally, as referenced in the Direct Testimony of Partner Witness Alley at page 18 and the Direct Testimony of Partner Witness Bram at page 12, the Partners will also appoint Board members that can provide a range of relevant experience in regulated businesses involving infrastructure, renewables, and energy transition to assist the Company. As referenced in the Direct Testimony of Partner Witness Alley at page 17 and the Direct Testimony of Partner Witness Bram at page 21, upon closing of the acquisition, GIP and CPP Investments will jointly govern ALLETE (and its parent, Alloy Parent LLC) through consent rights.

(b) **[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS…** [redacted] **…HIGHLY CONFIDENTIAL TRADE SECRET ENDS]**

Witness: Jeff Scissons
Response Date: 01/03/2025
Response by: n/a
Email Address: jscissons@allete.com
Phone Number: n/a

Witness: Jonathan Bram
Response Date: 01/03/2025
Response by: GIP
Email Address: discoverymanager@mnpower.com
Phone Number: n/a

Witness: Andrew Alley
Response Date: 01/03/2025
Response by: CPP Investments
Email Address: discoverymanager@mnpower.com
Phone Number: n/a

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E015/PA-24-198 ☐Nonpublic ☒Public
Requested From: Global Infrastructure Partners Date of Request: 12/18/2024
Type of Inquiry: General Response Due: 12/26/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Craig Addonizio
Email Address(es): craig.addonizio@state.mn.us
Phone Number(s): 651-539-1818

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

(c) Please refer to the supplemental response to DOC IR 0011 provided November 27, 2024. Please refer to DOC IR 0011.01 Attach HCTS, which includes non-binding substantive provisions and contemplates eventual execution of definitive documents between the Partners.

Witness: Jeff Scissons	Witness: Jonathan Bram	Witness: Andrew Alley
Response Date: 01/03/2025	Response Date: 01/03/2025	Response Date: 01/03/2025
Response by: n/a	Response by: GIP	Response by: CPP Investments
Email Address: jscissons@allete.com	Email Address: discoverymanager@mnpower.com	Email Address: discoverymanager@mnpower.com
Phone Number: n/a	Phone Number: n/a	Phone Number: n/a

The documents in Attachment CL-3 are designated as Confidential Trade Secret Information and are therefore omitted. They will be provided to parties that have signed the Protective Agreement.

The documents in Attachment CL-4 are designated as Highly Confidential Trade Secret Information and are therefore omitted. They will be provided to parties that have signed the Protective Agreement.

The documents in Attachment CL-5 are designated as Highly Confidential Trade Secret Information and are not for distribution to ALLETE. They are therefore omitted. They will be provided to parties that have signed the Protective Agreement, except for ALLETE.

ATTACHMENT CL-6

Clean Energy Organizations' Initial Comments on Minnesota Power 2021 IRP

STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan	**PUC Docket No. E015/RP-21-33**

CLEAN ENERGY ORGANIZATIONS' INITIAL COMMENTS

On Behalf Of
Fresh Energy
Clean Grid Alliance
Sierra Club
Minnesota Center for Environmental Advocacy

April 28, 2022

TABLE OF CONTENTS

SUMMARY OF ARGUMENT

As society's response to the climate crisis accelerates, Minnesota Power faces the very real prospect of having to entirely decarbonize its power supply between now and 2035 – precisely the term of its proposed 2021 Integrated Resource Plan ("IRP"). However, instead of presenting a flexible plan that could accommodate that goal, the utility's plan would build a new fossil gas plant while failing to retire its final decades-old coal plant. In these two conspicuous ways, this IRP is inconsistent with the public interest under Minnesota law, and the Commission should not approve it without modifications.

These comments are jointly filed by the nonprofit organizations Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy (collectively, the "Clean Energy Organizations," or "CEOs"). They draw upon expert technical analysis by Anna Sommer[1] and Chelsea Hotaling[2] of Energy Futures Group ("EFG"); Matthew Richwine of Telos Energy;[3] Elena Krieger,[4] Karan Shetty,[5] and Kelsey Bilsback[6] of Physicians, Scientists, and

[1] Anna Sommer is a Principal of Energy Futures Group and has supported the CEOs' work on integrated resource planning and related issues before this Commission since 2005.
[2] Chelsea Hotaling is a Consultant with Energy Futures Group and has conducted EnCompass modeling for IRP and certificate of need cases in several states.
[3] Matthew Richwine, B.S., M. Eng. in Power Systems Engineering, is a founding partner of Telos Energy and is a leader in power systems engineering, power electronic controls, and system stability.
[4] Elena Krieger, Ph.D., is the Director of Research at PSE Healthy Energy and has characterized operational, emissions, health, air quality, and environmental justice measures for power plants across the country. She holds a Ph.D. from the Department of Mechanical & Aerospace Engineering at Princeton University, where her research focused on optimizing energy storage in renewable energy systems and an AB in Physics and Astronomy & Astrophysics from Harvard University.
[5] Karan Shetty, M.ESM, is the Clean Energy Transition Analyst at PSE Healthy Energy where he works on energy equity and affordability, air pollution, and health impacts from fossil fuel power. He received his Master's in Environmental Science and Management from UCSB's Bren School, where he specialized in energy, climate, and carbon reductions, as well as strategic environmental communications and his undergraduate degree in Environmental Science from UCLA.
[6] Kelsey Bilsback, Ph.D., is Senior Scientist at PSE Healthy Energy where her work uses atmospheric modeling to evaluate the impacts of energy production and use on air quality and human health. She holds a Ph.D. in Mechanical Engineering and a B.A. in Physics.

Engineers for Healthy Energy; and Tyler Comings[7] and Joshua Castigliego[8] of Applied Economics Clinic. The CEOs additionally collaborated with the Union of Concerned Scientists in the preparation of these comments.

In Part I of these comments, CEOs show that Minnesota Power's IRP is fundamentally inconsistent with the carbon emission cuts needed to keep warming within the globally-agreed target of 1.5°C. Multiple recent studies setting forth pathways for the U.S. to achieve the needed decarbonization exclude all new combined cycle ("CC") gas plants like the proposed Nemadji Trail Energy Center ("NTEC") and retire old coal plants like Boswell by 2030. Minnesota Power's plans for NTEC and Boswell cause Minnesota Power's plan to fail under all five factors the Commission must consider under its resource planning rule.[9]

In Part II, CEOs discuss how the Commission has the authority and duty to determine in this docket whether continued investment in NTEC is in the public interest, yet Minnesota Power has not even attempted to make this showing. A core purpose of Minnesota's utility planning laws is to prevent the financial disasters caused in years past when utilities failed to adapt their power plant investment plans to changing circumstances (Part II.A). The Commission has repeatedly affirmed that prudence demands such adaptation, even when that means cancelling previously approved power plants (Part II.B). The continued pursuit of NTEC is also subject to Commission review under the Affiliated Interest Agreement statute, Minn. Stat. § 216B.48 (Part II.C), and

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[7] Tyler Comings is a Senior Researcher at the Applied Economics Clinic. He focuses on energy system planning (including integrated resource plans), costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. He has provided testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Ohio, Oklahoma, Maryland, Michigan, Missouri, New Jersey, Nova Scotia (Canada), and West Virginia.

[8] Joshua Castigliego is a Researcher and Assistant Director at the Applied Economics Clinic. He has more than four years of professional experience in energy and climate research and analysis, with a focus on decarbonization and pollution mitigation.

[9] Minn. R. 7843.0500, subp. 3.

under the expansive authority provided by Minn. Stat. § 216B.25 (Part II.D). In addition, important changes since the Commission considered NTEC in 2018, including more aggressive climate targets, greater risk that gas investments will be stranded, and Minnesota Power's parent company's decision to sell most of its share of NTEC, warrant an updated consideration of NTEC in this proceeding (Part II.E).

Part III details CEOs' EnCompass modeling, conducted by Energy Futures Group in collaboration with Applied Economics Clinic, which shows that an IRP that excludes NTEC is cost-effective and reduces financial, policy, and climate risk without sacrificing reliability. The CEO Preferred Plan replaces NTEC with more wind, solar, and battery storage resources, and it meets Minnesota Power's own modeled capacity needs and energy needs for all hours of the year throughout the planning period. CEOs' EnCompass modeling shows that the CEO Preferred Plan without NTEC is directly cost-competitive with Minnesota Power's Preferred Plan; indeed, the CEO Preferred Plan is slightly less expensive across several sensitivities, including in the reference scenario in a head-to-head comparison. CEOs' modeling also shows that the Hibbard coal and biomass plant can be retired, which, as we discuss in Section VIII, would deliver substantial public health benefits.

Part IV presents the findings of a detailed transmission reliability analysis, conducted by Telos Energy ("Telos"), which finds that the CEO Preferred Plan results in a no less reliable transmission grid than Minnesota Power's plan. Telos conducted its analysis using the same software modeling tools and underlying electricity system database as Minnesota Power. It found that Boswell unit 3 can retire reliably without NTEC, and that Minnesota Power must begin planning transmission mitigations now to reliably retire Boswell unit 4 by 2035 or sooner.

Part V discusses the broader need to plan for the retirement of Boswell 4. It highlights the failure of Minnesota Power's IRP to develop a plan to retire Boswell 4, despite already being ordered by the Commission to include a plan for the unit's early retirement and despite claiming that its proposed IRP will result in a generation mix that is coal-free by 2035. Part V explains why Minnesota Power must immediately begin planning the transmission upgrades needed to keep available the option of retiring Boswell 4 by 2030.

Part VI discusses how Minnesota's current CO_2 regulatory cost estimates fail to capture the full regulatory risk now faced by coal and gas. The estimates can also obscure true costs when applied – counterintuitively, Minnesota Power's modeling indicates that high carbon regulatory costs make Boswell 3 and 4 more competitive with lower-carbon scenarios rather than less. The Commission should recognize the limitations of current CO_2 regulatory cost estimates when assessing Minnesota Power's IRP and should commence a proceeding to update these estimates as contemplated by statute, along with the rules for their application.[10]

Part VII explores how a resource portfolio with more distributed solar, rather than one that focuses only on utility-scale solar, has the opportunity to be cleaner, be more equitable, create more jobs, and provide cost-effective solar to the system.

Part VIII presents the expert analysis of health and equity issues conducted by Physicians, Scientists, and Engineers for Healthy Energy ("PSE"). CEOs describe the considerable harm to human health that results from continuing to run the Boswell plant, along with the disproportionately large adverse health impact of the Hibbard plant, and the extent to which these harms fall disproportionately on vulnerable populations, especially Native communities. The PSE analysis also shows how factoring in upstream methane emissions dramatically increases NTEC's

[10] Minn. Stat. § 216H.06.

climate impact. This part of our comments further discusses how Minnesota Power can reduce the energy burden on low-income[11] ratepayers and explains why IRPs should include this sort of human health and equity analysis.

CEOs' recommendations to the Commission are set forth in detail at the end of this document. We respectfully request the Commission to: 1) modify Minnesota Power's Preferred Plan by removing NTEC, ordering the retirement of Hibbard, and finding the need for more solar power; 2) order the retirement of Boswell 3 by the end of 2029 (as proposed by Minnesota Power); 3) order Minnesota Power to commence planning sufficient to maintain the option of retiring Boswell 4 by 2030; 4) order Minnesota Power to work with stakeholders to identify steps needed to avoid foreclosing the ability to operate in alignment with 1.5°C pathways in its next IRP; 5) commence a proceeding to update CO_2 regulatory cost estimates and rules for their use; 6) order Minnesota Power to commence stakeholder outreach to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid, take steps to better align distribution and resource planning, and account for local community generation goals for distributed generation in its next IRP; 7) order that Minnesota Power's next IRP analyze public health impacts; and 8) order Minnesota Power to establish a stakeholder group to address equity issues, including disproportionate energy burdens.

[11] For the sake of consistency with utility filings and the PSE report, we used the term "low-income" in this comment. However, when not referring to defined terms, we strive to use "under-resourced" as a preferred term of art based on partner feedback.

I. MINNESOTA POWER'S CONTINUED COMMITMENT TO NTEC AND PLAN TO RUN BOSWELL 4 THROUGH 2035 ARE FUNDAMENTALLY INCOMPATIBLE WITH THE DEEP DECARBONIZATION NEEDED BY 2030 TO AVOID CATASTROPHIC CLIMATE CHANGE AND THUS INCONSISTENT WITH THE PUBLIC INTEREST UNDER STATE LAW

The Commission must assess Minnesota Power's resource plan based on whether it is "consistent with the public interest" under the state's resource planning statute.[12] In the last few years, new scientific findings have made it abundantly clear that deep decarbonization of electric utilities by 2030 is essential to protecting the public interest. Moreover, key to that decarbonization is ceasing the construction of new gas plants now, especially combined-cycle plants, and retiring existing coal plants by 2030. Minnesota Power's failure to drop its ill-advised plan to construct and operate the NTEC gas plant and its intent to continue running the coal-fired Boswell Unit 4 through at least 2035 are thus dangerously inconsistent with the public interest.

A. Changes In Climate Science And Policy In Recent Years Establish The Need For The Power Sector To Decarbonize Much Faster Than Previously Understood.

In late 2018, the Intergovernmental Panel on Climate Change ("IPCC") released a landmark report[13] showing how crucial it is to limit warming to 1.5°C above preindustrial levels, beyond which catastrophic global climate impacts become far more likely.[14] This report also found that to have a reasonable chance of staying within this limit, the world must cut greenhouse gas emissions roughly in half by 2030, go on to achieve net zero emissions by 2050, and then actually achieve net negative emissions in the second half of the century.[15] This demands a far faster rate

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[12] Minn. Stat. § 216B.2422, subd. 2(a).
[13] *Global Warming of 1.5°C: Special Report*: *Summary for Policymakers*, IPCC (2018) *available at* https://www.ipcc.ch/sr15/chapter/spm/ [hereinafter "IPCC 2018"].
[14] *Climate Change 2022: Impacts, Adaptation and Vulnerability: Summary for Policymakers*, IPCC (2022) *available at* https://www.ipcc.ch/report/ar6/wg2/ [hereinafter "IPCC 2022"] (including a recent description of the dangerous and widespread disruptions already unfolding from climate change, and a projection of future impacts).
[15] IPCC 2018, *supra* note 13, at C.1, C.3.

of decarbonization in this decade than regulators or policymakers have ever previously confronted. The report, along with a series of record-setting wildfires and other climate disasters, galvanized the global climate movement and raised the climate crisis to a first-tier political issue worldwide, including in the US.

In the November 2021 Glasgow Climate Pact, the nations of the world formally recognized the need for these deep emission cuts by 2030 in order to limit warming to 1.5°C.[16] The Pact stresses that such cuts require "*accelerated action in this critical decade*," and it calls upon parties to speed up their energy transition by "rapidly scaling up the deployment of clean power generation and energy efficiency measures, [and] accelerating efforts towards the phasedown of unabated coal power…."[17]

In short, the push to decarbonize has intensified as the focus has necessarily shifted from midcentury to 2030 – just 8 years away and well within the span of this IRP. Reflecting this new focus, the U.S. submitted a new Nationally Determined Contribution ("NDC") pledging to cut U.S. emissions by 50-52% below 2005 levels by 2030.[18] The governors of 24 states – including Minnesota – similarly pledged to cut net greenhouse gas emissions at least 50-52% by 2030.[19]

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[16] Glasgow Climate Pact, United Nations Climate Change Conference, at paras. 15,17 (Nov. 13, 2021) [hereinafter "Glasgow Pact"] *available at* https://unfccc.int/documents/310475. The world agreed to pursue efforts to limit warming to 1.5° C in the 2015 Paris Agreement and reaffirmed that goal in the Glasgow Pact. The Glasgow Pact recognizes that "limiting global warming to 1.5 °C requires rapid, deep and sustained reductions in global greenhouse gas emissions, including reducing global carbon dioxide emissions by 45 percent by 2030 relative to the 2010 level and to net zero around mid-century…" *Id*. at para. 17.

[17] *Id*. at paras. 18 (emphasis added), 20.

[18] *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies*, U.S. White House (Apr. 22, 2021), *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/ [hereinafter "White House Fact Sheet"].

[19] *U.S. Climate Alliance Commits to Achieve Net-Zero Emissions No Later than 2050*, U.S. Climate Alliance (Apr. 23, 2021) *available at* http://www.usclimatealliance.org/publications/newtargets.

Achieving 100% carbon-pollution-free electricity by 2035 is a key part of meeting the nation's pledge under its NDC.[20] Thus, the U.S. power sector faces the challenge of making far deeper cuts than any other sector by 2030 and faces the prospect of needing to completely decarbonize by 2035, just 8 years after NTEC is currently scheduled to come online.[21]

This "power sector first" approach to economy-wide decarbonization reflects the game-changing and ongoing technological advances in renewable energy and storage (discussed more in Part II.E.2 below), which allow faster and cheaper carbon reductions from the power sector than from other sectors. And other sectors of the economy are expected to decarbonize largely by replacing their own fuel use with electricity, making the power sector the cornerstone of broader decarbonization throughout the economy.

CEOs commend the carbon reductions that Minnesota Power has achieved over the past several years. The utility and its customers are in a far better position now than they would have been if Minnesota Power had not invested in more renewable power and reduced its former 95% dependence on coal. However, Minnesota Power still has a very long way to go, and its Preferred Plan does not match the pace and scale called for by climate science and decarbonization pathways.

B. Pathways To Achieving The Deep Decarbonization Needed By 2030 Exclude New Gas Plants Like NTEC And Retire Coal Plants Like Boswell By 2030.

Since the IPPC's 2018 report, multiple national modeling analyses have been published charting feasible and least-cost pathways to achieving deep decarbonization at the scale and speed needed to preserve a reasonable chance to limit warming to 1.5°C.[22] The studies of most relevance

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[20] White House Fact Sheet, *supra* note 18.
[21] Letter from Daniel McCourtney, NTEC Environmental & Land Manager, to Wisconsin Public Service Commission, Docket Nos. 9698-CE-100 and 9698-CE-101, (Jan. 26, 2022).
[22] *See, e.g.,* Robbie Orvis, *A 1.5 Celsius Pathway to Climate Leadership for the United States*, Energy Innovation (Feb. 2021), *available at* https://energyinnovation.org/wp-content/uploads/2021/02/A-1.5-C-Pathway-to-Climate-Leadership-for-The-United-States.pdf [hereinafter "Orvis, 2021"]; Nathan Hultman,

to this proceeding, those that focus on the carbon reductions needed by 2030, preclude projects like NTEC and require existing coal plants like Boswell to come off the grid by 2030.[23] Even studies that focus primarily on achieving net zero by 2050 — taking a slower linear reduction pathway that does not quite make the cuts the IPCC says are needed in the 2020s — call for declines in gas generation by 2030 and drive all or virtually all coal power off the grid by 2030.

A leading modeling study, published by Energy Innovation in February 2021, describes how the nation can cut emissions in half by 2030 economy-wide, consistent with the new U.S. NDC and the IPCC's report.[24] Like other similar studies, it finds that particularly deep emission cuts must come from the power sector. The "linchpin of economywide decarbonization," Energy Innovation finds, is achieving 80% carbon-free electricity in 2030 and 100% in 2035,[25] consistent with the Biden Administration's goal. The analysis states that achieving these cuts "requires not building any new gas plants that lack carbon capture," noting that the U.S. "already has a massive oversupply of gas plants, many of which are likely to become stranded assets, and no reason exists to build more gas plants."[26] It also states that "[e]liminating coal power plant emissions is a critical component of achieving the 2030 emissions reduction target. Our analysis finds that without

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et al., *Charting an Ambitious U.S. NDC of 51% Reductions by 2030*, Univ. Md. Center for Global Sustainability (Mar. 2021), *available at* https://cgs.umd.edu/research-impact/publications/working-paper-charting-ambitious-us-ndc-51-reductions-2030 [hereinafter "Hultman, et al., 2021"]; *2035: The Report: Plummeting Solar, Wind and Battery Costs Can Accelerate our Clean Energy Future*, Goldman School of Public Policy (June 2020), *available at* https://www.2035report.com/electricity/ [hereinafter "2035 Report"]; *2030 Report: Powering America's Clean Economy, A Supplemental Analysis to the 2035 Report*, Goldman School of Public Policy (April 2021), *available at* https://gspp.berkeley.edu/faculty-and-impact/centers/cepp/projects/2030-report-powering-americas-clean-economy [hereinafter "2030 Report"].

[23] Orvis, 2021, *supra* note 22, at 8; Hultman et al., 2021, *supra* note 22, Technical App. at 4; 2035 Report, *supra* note 22, at 20; 2030 Report, *supra* note 22, at 3-4.

[24] Orvis, 2021, *supra* note 22.

[25] *Id*. at 4.

[26] *Id*. at 8.

eliminating coal emissions by 2030, achieving U.S. emissions reductions in line with limiting warming to [1.5°C] is impossible."[27]

A March 2021 study published by the Center for Global Sustainability at the University of Maryland similarly shows how the nation could cut emissions by 51% by 2030.[28] It stresses that "U.S. climate ambition by 2030 hinges fundamentally on the ability to rapidly shift to zero-emissions electricity generation."[29] The pathway it charts requires that by 2025 any new gas plants be built with carbon capture and storage ("CCS"), and it largely eliminates coal power without CCS by 2030.[30]

A 2021 supplement to a major analysis published by the Goldman School of Public Policy at the University of California, Berkeley, focuses directly on electricity and charts a path for reducing power sector greenhouse gas emissions by 80% by the year 2030.[31] Like the other reports, the study excludes new gas plants beyond those already under construction and eliminates all coal power by 2030.[32]

At least three other major new studies published since December of 2020 model pathways to achieving the longer-term goal of net-zero U.S. greenhouse gas emissions economy-wide by 2050.[33] These studies, including one published by the National Academy of Sciences, model somewhat less ambitious pathways than the studies mentioned above because they do not aim for

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[27] *Id*. at 6.
[28] Hultman, et al., 2021, *supra* note 22.
[29] *Id*. at 2.
[30] *Id*. at 2, Technical App. at 4.
[31] 2030 Report, *supra* note 22.
[32] *Id*. at 22.
[33] *Accelerating Decarbonization of the U.S. Energy System*, National Academies of Sciences, Engineering, and Medicine, The National Academies Press (2021) *available at* https://www.nap.edu/catalog/25932/accelerating-decarbonization-of-the-us-energy-system [hereinafter "National Academies"]; James H. Williams, et al., *Carbon-Neutral Pathways for the United States*, AGU Advances (2021) *available at* https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2020AV000284; Eric Larson, et al., *Net Zero America: Potential Pathways, Infrastructure, and Impacts, Interim Report*, Princeton, New Jersey (Oct. 29, 2021), *available at* https://acee.princeton.edu/rapidswitch/projects/net-zero-america-project/.

the roughly 50% emission cuts by 2030 that the IPCC report says are needed.[34] Even so, they all stress the need for aggressive action in the next 10 years, including greatly accelerating the deployment of renewables and energy storage. For example, the National Academies report finds that by 2030 the nation needs to deploy about two to three times existing wind capacity and about four times existing solar capacity, plus add 10-60 GW of new battery storage.[35] The report stresses that the rapid drop in price of all these technologies – between nearly 70 and 90% in just the past decade – has "transformed the economics of decarbonization."[36] Costs for these technologies, particularly solar PV and battery storage, are expected to continue to decline in the future.[37] CEO's modeling in this case used the most recent forecast data available in order to reflect these expectations.

While the pathways identified in these three 2050-focused reports do not involve retiring existing gas plants in this decade, they all present scenarios showing gas generation declining by 2030 and gas plant capacity factors falling.[38] Moreover, they all depend on the aggressive retirement of coal plants. One of these studies, by Princeton researchers, looks at five different pathways to net zero emissions by 2050, and "[i]n all five cost-minimized energy-supply pathways, with a linear decline to net-zero emissions by 2050, coal use is essentially eliminated by 2030."[39] Among the "Key Actions Necessary by 2030" identified in the National Academies report is

[34] *Recapturing U.S. Leadership on Climate,* Environmental Defense Fund, 13 (Mar. 3, 2021) *available at* https://www.edf.org/climate/recapturing-us-climate-leadership.
[35] National Academies, *supra* note 33, at 75.
[36] *Id.* at 3, 60.
[37] *2021 Electricity ATB Technologies and Data Overview*, National Renewable Energy Laboratory, *available at*: https://atb.nrel.gov/electricity/2021/index.
[38] National Academies, *supra* note 33, at 105 (gas generation declines 10-30% by 2030); Williams et al. at 12, Fig. 7 (showing capacity factors for CCGT units starting to plummet around 2025); Larson et al. at 30, 87 (gas generation declines 2-30% by 2030, except in one of the five scenarios examined, in which renewable energy is constrained and which relies more heavily on carbon capture and storage).
[39] Larson, *supra* note 33, at 27.

"[r]etire as much as 100 percent of installed coal-fired capacity by 2030 (or retrofit with systems to capture ≥90 percent of CO_2 emissions)".[40] The third report analyzes multiple decarbonization pathways, and while the pathways diverge after 2035, it identifies with high confidence particular high-priority actions needed this decade, including coal retirement to reach less than 1% of total U.S. generation by 2030.[41] And these U.S.-focused reports are echoed by a major new global analysis by the International Energy Agency, which finds that achieving the global emission cuts needed to reach net zero by 2050 requires that all advanced nations eliminate coal power without carbon capture technology by 2030.[42]

In sum, a remarkable consensus has emerged around the steps needed by 2030 to preserve the possibility of limiting warming sufficiently to avoid catastrophic global climate changes; specifically, we must stop building new gas plants, and we must retire old coal plants by the end of this decade. Minnesota Power's IRP is conspicuously incompatible with this consensus given its ongoing plans to build NTEC and its failure to plan for Boswell 4's retirement.

C. Minnesota Power's Preferred Plan Minimizes Flexibility While Increasing Risk And Fails Under All Five Factors The Commission Must Consider Under Its Planning Rule.

Minnesota Power's Preferred Plan – to keep investing in and depending on NTEC and Boswell – carries tremendous inherent risk. There is a worldwide effort underway to cut emissions enough to limit warming to 1.5°C, and multiple pathway studies make clear what this means for the power sector. Any utility making long-term plans that ignore this global effort is asking its customers to shoulder an immense risk.

[40] National Academies, *supra* note 33, at 90.
[41] Williams, *supra* note 33, at 20.
[42] *Net Zero by 2050: A Roadmap for the Global Energy Sector,* International Energy Agency, 116 (Oct. 2021) *available at* https://www.iea.org/reports/net-zero-by-2050.

Minnesota Power's failure to withdraw from NTEC or accelerate the complete retirement of Boswell results in a risky plan that falls short on all five factors the Commission must consider under its IRP rule.[43] Policy and economic changes this decade could well drive the cancellation of NTEC when it is partially constructed, after millions more dollars are spent on the project. If NTEC does come online, it could be forced to run at levels much lower than expected or to close just a few years later. Or it could be forced to install carbon capture technology or convert to hydrogen – both costly alternatives depending on as-yet noncommercial technology and unbuilt infrastructure. As for Boswell, it could be driven to closure by 2030 or sooner, given the importance of coal plant closures to meeting the nation's climate goals. Minnesota Power asserts it will take a decade to build the transmission upgrades needed to replace Boswell 4.[44] If so, the need to close by 2030 could require the utility to rush to replace the energy, capacity, and grid support the plant provides, forcing it to accept costly options it could have avoided with better planning. Ignoring these risks threatens system reliability and rates, the first two factors the Commission must consider under Minn. R. 7843.0500, subp. 3(A) and (B).

Minnesota Power's plan also fails to minimize adverse environmental and socioeconomic impacts under subpart 3(C). The plan does not minimize carbon emissions or the heavy burden that Boswell places on public health which falls disproportionately on vulnerable communities.[45]

Additionally, relying on NTEC and Boswell clearly increases the "risk of adverse effects … from financial, social, and technological factors that the utility cannot control," and constrains rather than enhances "the utility's ability to respond" to changes in those factors, under subparts

[43] Minn. R. 7843.0500, subp. 3.
[44] See Part V.C.
[45] See Part VIII.

3(D) and (E). These factors essentially require that long-term plans account for how the world is changing around them and respond accordingly to protect host communities and ratepayers alike.

II. THE COMMISSION HAS THE AUTHORITY AND RESPONSIBILITY TO DETERMINE IN THIS DOCKET WHETHER CONTINUED INVESTMENT IN THE NEMADJI TRAIL ENERGY CENTER IS IN THE PUBLIC INTEREST, YET MINNESOTA POWER HAS NOT EVEN ATTEMPTED TO MAKE THIS SHOWING

The Commission is required to "approve, reject, or modify the [resource] plan of a public utility . . . consistent with the public interest."[46] The Commission cannot assess whether Minnesota Power's overall resource plan is consistent with the public interest without assessing whether NTEC – the plan's single largest and riskiest new resource investment – is in the public interest. The burden that Minnesota Power bears is particularly evident given the non-renewable nature of NTEC. Under the State's renewable energy preference, Minnesota Power must not only show that continuing to pursue NTEC is in the public interest but that "a renewable energy facility is not in the public interest."[47]

Minnesota Power has submitted a resource plan that fails to assess whether NTEC is in the public interest. This planning process provided an ideal opportunity for Minnesota Power to assess whether a long-term investment in a new carbon-emitting resource makes sense under current conditions. Instead of seizing this opportunity, Minnesota Power chose to treat NTEC as if its future construction was inevitable, despite materially changed circumstances and the fact that construction has not begun. When CEOs asked whether Minnesota Power had done any modeling runs that did not presume NTEC would be built and that allowed the model to compare it to other resources, the company responded that NTEC is an "approved project," that it included NTEC in

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[46] Minn. Stat. § 216B.2422, subd. 2(a).
[47] Minn. Stat. § 216B.2422, subd. 4.

the modeling as a "base case resource," and that it "did not conduct IRP modeling runs without the project."[48]

Minnesota Power's choice to lock NTEC into every single one of its modeling runs reveals a troubling lack of investment prudence. Minnesota ratepayers, not private investors, bear the financial risk of the company's share of NTEC and must receive a compelling showing that investing in NTEC makes financial sense today given the unprecedented pressure to decarbonize the power sector and given the advances in carbon-free technology. Protecting ratepayers' interest necessitates a robust inquiry into whether committing millions more to the as-yet unbuilt project is prudent. Minnesota Power's response that it had decided not to look into this urgent question[49] – even while going through a long-term planning process with a full suite of analytic tools – is insufficient.

And yet, Minnesota Power is asking the Commission to find that its resource plan is in the public interest even though it has not considered whether this major, controversial project makes any sense today. Minnesota Power seems to believe that once a major new power plant is approved by the Commission, the utility can ignore emerging concerns that undermine the investment during the four years prior to ever breaking ground for the project, even as background circumstances, the project's construction schedule, and MP's share of the project change. This unreasonable assumption runs afoul of Minnesota's resource planning laws and the Commission's many decisions establishing the opposite principle.

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[48] Minnesota Power Response to CEO IR 056, Docket No. E015/RP-21-33 (May 24, 2021).
[49] Indeed, Minnesota Power declined to reassess its modeled investment in NTEC even while its own affiliate was selling most of its ownership stake in NTEC, as discussed more in Part II.E.3.

A. A Core Purpose Of Minnesota's Resource Planning Laws Is To Require Utilities To Monitor Changing Circumstances And Adjust Their Resource Plans In Response.

The need for utilities to revisit their construction plans in light of market and regulatory changes is one of the key objectives of Minnesota's resource planning rules. As noted above, two of the five regulatory criteria that the Commission must consider when assessing a resource plan focus on the threat posed by external "financial, social and technological factors."[50] The first such criterion asks whether the plan enhances the utility's ability to respond to changes in these factors affecting its operations.[51] In its 1990 Statement of Need and Reasonableness ("SONAR") adopting this provision the Commission stated:

> The events of the past 15 to 20 years have demonstrated clearly that utilities are affected by a multitude of supply and demand uncertainties. Planning errors across the United States have translated into billions of dollars of plant disallowances and/or rate increases. It is possible to minimize the effect of planning errors if utility plans remain flexible and respond to changing conditions.[52]

The events the Commission refers to date to the 1970s and 1980s, when U.S. utilities spent huge sums pursuing nuclear and coal plants even after shrinking demand forecasts, skyrocketing costs, growing public opposition, and new regulations made these projects imprudent. Nearly 100 nuclear plants and 75 coal plants had to be canceled, many of which had already been under construction for years, and sunk costs for the canceled nuclear plants alone were in the billions of dollars.[53] Some of these losses were passed on to ratepayers, contributing to the three-fold increase

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[50] Minn. R. 7843.0500, subp. 3 (D)-(E).
[51] Minn. R. 7843.0500, subp. 3(D)("Resource options and resource plans must be evaluated on their ability to . . . (D) enhance a utility's ability to respond to changes in the financial, social, and technological factors affecting its operations").
[52] Statement of Need and Reasonableness, *In the Matter of the Proposed Adoption of Rules Governing the Resource Planning Process for Electric Utilities, Minn. Rules, Parts 7843.0100 to 7843.0600*, Minn. Pub. Utils. Comm'n., Docket No. E-999/R-89-201, 21 (Jan. 19, 1990), [hereinafter "IRP SONAR"], *available at* https://www.revisor.mn.gov/rules/status/rule/R-01617.
[53] *See* Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry*, 11-12 (March 1986) *available at* https://www.cbo.gov/sites/default/files/99th-congress-1985-1986/reports/doc10b-entire_1.pdf.

in electric rates between 1972 and 1984; other losses were borne by utilities, causing considerable financial distress within the industry.[54] A 1986 federal analysis of that distress noted that utilities that quickly canceled power plants in response to changing conditions fared better financially than utilities that were slower to cancel plants.[55]

Similarly, Minnesota's IRP rule requires the Commission to assess a resource plan based on the plan's ability to "limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."[56] The SONAR discusses, by way of example, the risk from factors such as changing public attitudes about nuclear power and the development of new energy technologies.[57] Today's growing understanding of the climate crisis, intensifying opposition to fossil fuels, increasing carbon scrutiny by the private sector and capital markets,[58] and rapid advances in carbon-free technologies all fall squarely within the type of "financial, social, and technological factors" both these rule provisions refer to.

Monitoring and responding to changing circumstances are such core aspects of the resource planning process that the Commission has stressed them multiple times in the standard language it uses in its IRP orders, including in its order approving with modifications Minnesota Power's last IRP:

> The [resource planning] process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future

[54] *Id*. at 9.
[55]*Id*. at 13-14.
[56] Minn. R. 7843.0500, subp. 3(E).
[57] IRP SONAR, *supra* note 52, at 21.
[58] *See e.g.,* Larry Fink, *2022 Letter to CEOs: The Power of Capitalism* (2022) *available at* https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter. "It's been two years since I wrote that climate risk is investment risk. And in that short period, we have seen a tectonic shift of capital. Sustainable investments have now reached $4 trillion. Actions and ambitions towards decarbonization have also increased. This is just the beginning – the tectonic shift towards sustainable investing is still accelerating. Whether it is capital being deployed into new ventures focused on energy innovation, or capital transferring from traditional indexes into more customized portfolios and products, we will see more money in motion. Every company and every industry will be transformed by the transition to a net zero world. The question is, will you lead, or will you be led?"). *Id*.

> needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.[59]

Or as the Department of Commerce put it in the recent Xcel IRP docket, electric utilities are expected "to be aware of current market conditions and to prudently adapt to those conditions rather than blindly pursue a path pre-determined months or years before."[60]

It is important for utilities and their regulators to assess continued construction of power plants even long after construction has begun, as the case law discussed below shows. In this case, construction has not yet even begun for NTEC. According to Wisconsin regulatory filings, Minnesota Power and the other project developers currently plan to commence construction in September 2022, and commercial operation has been delayed until March 2027.[61] Construction may be further delayed by litigation over the project in Wisconsin, or permanently blocked by its outcome.[62] The Commission therefore has the opportunity in this docket to assess the wisdom of continuing to pursue NTEC while the project is still at a preliminary stage.

In short, there is nothing in the planning rule that supports Minnesota Power's choice in this resource plan to ignore the critical question of whether continued pursuit of NTEC is in the public interest. The fact that the project was approved years ago does not give Minnesota Power permission to avoid considering in its current resource planning how the case for the plant has

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[59] Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, Order Approving Plan with Modifications, Docket No. E-015/RP-15-690, 2-3 (July 18, 2016).
[60] Minnesota Department of Commerce, Division of Energy Resources, *In the Matter of Xcel Energy's 2019-2034 Upper Midwest Integrated Resource Plan*, Initial Comments, Docket No. E002/RP-19-368, 100 (Feb. 11, 2021).
[61] Letter from Daniel McCourtney, NTEC Environmental & Land Manager, to Wisconsin Public Service Commission, Docket Nos. 9698-CE-100 and 9698-CE-101, (Jan. 26, 2022).
[62] The Certificate of Public Convenience and Necessity issued by the Wisconsin Public Service Commission remains on appeal in a case brought by Clean Wisconsin and Sierra Club. Clean Wisconsin v. Pub. Serv. Comm'n of Wisc., Dane County Circuit Court, Docket No. 2020-CV-585 (Feb. 28, 2020).

since eroded. On the contrary, a core goal of resource planning is to encourage utilities, in the words of the Commission's SONAR, to "remain flexible and respond to changing conditions."[63]

B. The Commission Has Repeatedly Reaffirmed A Utility's Obligation To Consider Whether Continued Investment In A Power Plant Is Prudent When Circumstances Have Changed, Including Investments In A Plant Previously Approved By The Commission.

The debate over whether and when a utility should have canceled a proposed power plant often occurs after the fact, when the Commission is faced with a utility's request to recover its financial losses from ratepayers. The Commission's responsibility to establish just and reasonable rates requires it to ensure utilities recover from ratepayers only their prudently incurred costs. [64] While this proceeding is not a rate case, the Commission's decisions regarding investment prudence are directly relevant. Certainly, a utility's plan to make an imprudent investment cannot be considered to be in the public interest under Minn. Stat. § 216B.2422, subds. 2(a) and 4.

The Commission's prudence decisions dating back to at least 1987 establish that utilities must prudently assess not only whether to initiate a power plant project but also the distinct question of whether to keep investing in a project as circumstances change. [65] Moreover, multiple recent decisions establish that this obligation does not vanish just because the initial decision to invest in the project has been granted regulatory approval. In three cases where utilities sought recovery of expenditures for canceled projects, the Commission considered the prudence of both

[63] IRP SONAR, *supra* note 52, at 21.
[64] Minn. Stat. § 216B.16. The Minnesota Court of Appeals has stated that "prudency of investment is a fundamental consideration in determining whether a utility's proposed rates are just and reasonable." *In Re Petition of Interstate Power Company for Authority to Increase its Rates for Electric Service in Minnesota*, 416 N.W. 2d 800, 806 (Minn. App. 1987).
[65] Minn. Pub. Utils. Comm'n, *In the Matter of the Petition of Interstate Power Company For Authority to Increase its Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions of Law, and Order. Docket No. E-001/GR-86-384 (May 1, 1987). In that case, regarding a canceled nuclear plant, the Commission allowed partial rate recovery of the initial planning costs, which it held to have been prudent, but "costs other than preliminary planning were unnecessary and cannot reasonably be assigned to ratepayers." *Id*. at 17.

the initial decision to pursue the project and the subsequent decision to withdraw from it after circumstances had changed. In all three cases – regarding the Big Stone II coal unit,[66] the Sutherland IV coal unit,[67] and the Prairie Island uprate[68] – the project had received advance approval yet changes in the regulatory and economic landscape later rendered the project contrary to the public interest.

The Commission found in all three cases that the utilities in question had prudently initiated the projects and after circumstances changed, they had prudently withdrawn from them. The Commission allowed the utilities to amortize these costs, repeating the exact same language in each case to explain that disallowing costs prudently incurred in good faith could potentially chill a utility's "diligence in developing resources *and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.*"[69] In the case of Xcel Energy's withdrawal from the planned Prairie Island uprate, on which it had already spent $79 million, the Commission praised the company's timely response to "new realities" and "changed circumstances," indicating that it might view the situation differently if Xcel had "fail[ed] to recognize, react to, and disclose signs of trouble as they developed."[70]

The Commission has also recently assessed a utility's prudence in implementing a project that was not canceled but had enormous cost overruns. Xcel's project extending the life of and

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[66] Minn. Pub. Utils. Comm'n. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-017/GR-10-239 (April 25, 2011) [hereinafter "Big Stone II Order"].
[67] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-001/GR-10-276 (Aug. 12, 2011) [hereinafter "Sutherland IV Order"].
[68] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-002/GR-13-868 (May 8, 2015) [hereinafter "Prairie Island Order"].
[69] Big Stone II Order, *supra* note 66, at 11; Sutherland IV Order, *supra* note 67, at 33; Prairie Island Order, *supra* note 68, at 33 (emphasis added).
[70] Prairie Island Order, *supra* note 68, at 32.

uprating the Monticello nuclear plant ran hundreds of millions of dollars over the original estimate, and the Commission launched a proceeding to investigate whether Xcel had been imprudent in managing the project. The Administrative Law Judge in that proceeding concluded that to satisfy its burden of proof for rate recovery, Xcel had to not only show it was prudent to begin the project but that "all of the subsequent decisions were prudent."[71] The ALJ quoted the testimony of an Xcel witness, who acknowledged that prudence involved asking whether, as circumstances changed, "did the company properly think through what its options were and to what extent did the company respond to those changed circumstances in prudent fashion?"[72] The ALJ, and the Commission, found Xcel's management failed to respond to those changes prudently, and Xcel was ultimately denied a return on the project's cost overruns.[73]

This case law unequivocally shows that whether to commence a power plant project and whether, years later, to continue pursuing it are legally distinct questions. Utilities hoping to pass the enormous costs of a new power plant on to Minnesota ratepayers,[74] therefore, cannot rely on the Commission's initial approval of the plant as a reason to avoid scrutinizing, during the several

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[71] Office of Administrative Hearings, In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns, *Findings of Fact, Conclusions of Law, and Recommendations,* Docket No. E-002/CI-13-754, 34 (Feb. 2, 2015).

[72] *Id*.

[73] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes*,* Docket No. E-002/CI-13-754, 3 (May 8, 2015).

[74] Even though the nominal owner of NTEC is Minnesota Power's affiliate, South Shore Energy LLC, Minnesota Power stated in its petition seeking approval of the plant that "Minnesota Power is treating its investment in NTEC as the equivalent of a utility-owned and rate-based asset." Minnesota Power, *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Petition for Approval, Docket No. E015/M/AI-17-568, at 6-40 (July 28, 2017) [hereinafter "EnergyForward Petition"]. Moreover, Attachment A to the Commission's order approving NTEC says that the costs approved in that docket will be the "starting point for review in the [future] rate case." Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Order Approving Affiliated-Interest Agreements with Conditions, Docket No. E-015/M/AI-17-568, 21 (Jan. 24, 2019) [hereinafter "AIA Approval"].

years between approval and groundbreaking, whether the project remains in the public interest. The Commission's earlier NTEC decision addressed whether it was reasonable in 2018 to pursue a combined cycle plant expected to come online in 2024.[75] The question before the Commission today is whether it is in the public interest in 2022 to keep pursuing a combined cycle plant scheduled to come online in 2027. Minnesota Power is not only asking the Commission to ignore this second question, but the utility itself chose to ignore the question in its IRP and EnCompass modeling. This choice was imprudent given the new realities the plant faces.

Moreover, ample evidence in this docket compels a Commission finding that continuing to pursue NTEC is imprudent and not in the public interest. In addition to the changed circumstances making NTEC inconsistent with the public interest (described in Parts I and II.E), the CEOs' modeling shows that renewable options can reliably and cost-effectively replace NTEC (presented in Parts III and IV).

C. The Affiliated Interest Agreement Statute Gives The Commission Continuing Supervisory Control Over Agreements It Has Approved.

The Commission approved NTEC in 2018 under the affiliate interest agreement (AIA) provisions of Minn. Stat. § 216B.48, but that law does not require that the Commission end its scrutiny of AIAs after initial approval. On the contrary, subdivision 6 specifies that the Commission retains "continuing supervisory control over the terms and conditions of the contracts . . . so far as necessary to protect and promote the public interest."[76]

This continuing supervisory control requirement provides the Commission with direct authority to review NTEC in this IRP. It constitutes authority for the Commission to find that Minnesota Power's AIAs to build and operate NTEC are no longer reasonable and consistent with

[75] AIA Approval, *supra* note 74, at 10.
[76] Minn. Stat. § 216B.48, subd. 6.

the public interest, and to make that finding as soon as that unreasonableness becomes apparent. Waiting until years later in a rate case to disallow unreasonable payments would render meaningless the "continuing supervisory control" requirement. In this way, the law demonstrates a clear preference that the Commission prevent unreasonable expenditures made through AIAs before they are made, rather than disallow them after the fact.

The Commission should exercise its continuing supervisory authority over the NTEC AIAs now, through this IRP. The IRP process gives the Commission the opportunity to analyze fully-modeled resource plans with and without NTEC. (Prior to this proceeding, NTEC has never been assessed in the context of a full IRP, and certainly not under the current economic and policy landscape.[77]) And the IRP statute already imposes upon the Commission the affirmative obligation to determine if NTEC is in the "public interest" – the same standard the Commission must apply in its supervision of an AIA.

Moreover, there was a major change in the contractual arrangements governing NTEC when Minnesota Power's parent company sold more than half its share of the plant to Basin Electric Power Cooperative (discussed more below at Part II.E.3).[78] Despite this change, Minnesota Power has not renegotiated or amended its AIAs with South Shore Energy LLC, nor did it announce whether the sale meant Minnesota Power would be taking a different percentage

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[77] In Minnesota Power's 2016-2030 IRP, the utility proposed using a bidding process to add a generic 200-300 MW of gas combined cycle generation. The Commission order approving the plan with modifications allowed Minnesota Power to pursue the bidding process to investigate this option, but it explicitly said this decision "establishes no presumption that any or all of the generation identified in that bidding process will ultimately be approved," and required that the next resource plan "include a full analysis of all alternatives to natural gas." Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, Order Approving Resource Plan with Modifications, Docket No. E-015/RP-15-690 (July 18, 2016) at 9. However, Minnesota Power sought approval of NTEC under the Affiliated Interest Statute instead of within the context of a full-fledged IRP. EnergyForward Petition, *supra* note 74.

[78] ALLETE, *ALLETE Announces Third Partner in Nemadji Trail Energy Center Project*, (Sept. 28, 2021) *available at*: https://investor.allete.com/news-releases/news-release-details/allete-announces-third-partner-nemadji-trail-energy-center#:~:text=28%2C%202021%2D%2D%20ALLETE%2C%20Inc,Cooperative%20for%20approximately%20%2420%20million%20 [hereinafter "ALLETE Press Release"].

of the plant's energy and capacity. In response to an information request from CEOs asking how much of the energy and capacity the utility currently intends to purchase during the years of the resource plan, Minnesota Power stated that it "anticipates it will be taking 20% of the facility."[79] However, the company also stated that it does not intend to update its Capacity Dedication Agreement[80] and submit it to the Commission for consideration until "all ongoing facility permitting processes are complete."[81]

Minnesota Power's roundabout approach, which would build the plant before the Commission reviews an updated AIA, would prevent the Commission from exercising its "continuing supervisory control" over this AIA before construction, and it is a further reason why the Commission should analyze the NTEC project in <u>this</u> proceeding.

D. The Commission Has Broad Authority To Rescind Or Amend Prior Orders Under Minn. Stat. § 216B.25.

The Legislature has also granted the Commission expansive authority to reassess prior decisions as circumstances change. Minnesota Statutes § 216B.25 allows the Commission to reopen, rescind, or change past Commission orders in the public interest.[82] Revisiting a past decision under Minn. Stat. § 216B.25 does not require that the past decision was in error, nor does it require the presence of extraordinary circumstances. Rather, the Commission's authority extends to all situations where revisiting a past decision is in the public interest.

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[79] Minnesota Power Response to CEO IR 077, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[80] The Capacity Dedication Agreement, one of the approved affiliated interest agreements, says that Minnesota Power is offtaking 50% from the facility. *Id*.
[81] *Id*.
[82] "The commission **may at any time**, on its own motion or upon motion of an interested party, and upon notice to the public utility and after opportunity to be heard, **rescind, alter, or amend any order** fixing rates, tolls, charges, or schedules, or any other order made by the commission, and may reopen any case following the issuance of an order therein, for the taking of further evidence or for any other reason. Any order rescinding, altering, amending, or reopening a prior order shall have the same effect as an original order." Minn. Stat. § 216B.25 (emphasis added).

The plain language of the statute evidences the breadth of the Commission's power: with or without prompting by an interested party, the Commission can change *any* past order, at *any* time.[83] Furthermore, principles of res judicata and collateral estoppel do not apply to the Commission's decision to reopen a past order.[84] Therefore, the previously approved AIAs do not bar the Commission from amending Minnesota Power's resource plan to exclude NTEC. Rather, this IRP presents an opportunity for the Commission to reassess those AIAs, and their waning prudence. Parallel to Minnesota Power's duty to continually reassess the wisdom of its planned investments, the Commission has the authority to benefit from hindsight.[85]

Revisiting a past decision under Minn. Stat. § 216B.25 does not require a finding that the past decision was in error. In *Matter of City of White Bear Lake's Request for an Elec. Util. Serv. Area Change Within Its City Limits* ("*White Bear Lake*"),[86] the City of White Bear Lake asked the Commission to use its § 216.25 powers to revisit the 1975 utility service area map and change the boundaries between two utilities. The Commission refused, and the city appealed.[87] The Court disagreed with the City's contention that the original 1975 service area was in error. However, the Court held that § 216B.25 grants the Commission broad powers to revisit past decisions. The relevant question is not whether the original decision was in error, but whether altering the decision would serve the public interest.[88]

Furthermore, using Minn. Stat. § 216B.25 does not require extraordinary circumstances, only evidence that revisiting the decision is in the public interest. In *White Bear Lake*, the

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[83] *Id*.
[84] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Peoples Nat. Gas Co. for Auth. to Increase Rates for Gas Util. Serv. in Minnesota*, Findings of Fact, Conclusions of Law, and Order, 11 (Feb. 8, 1984).
[85] Minn. Stat. § 216B.25.
[86] 443 N.W.2d 204, 207 (Minn. Ct. App. 1989).
[87] The Commission originally did grant the request, but then reversed itself. *Id*.
[88] *Id*.

Commission also argued that it could not revisit the original service area boundaries absent extraordinary circumstances.[89] The Court of Appeals rejected this argument, observing that § 216B.25 provides the Commission with great flexibility in revising any order at any time.[90] The statute allows the commission to decide anew whether a past decision still serves the public interest, without being bound by past reasoning.

In the past, the Commission has found it appropriate to use § 216B.25 when a petitioner presents new evidence or issues that require further consideration by the Commission. For example, in *In the Matter of Awa Goodhue Wind, LLC's Application for A Certificate of Need*,[91] a project proposer obtained a Certificate of Need for a wind project in 2011. The project was not built on time, and the proposers asked the Commission to allow the Certificate of Need to stand, despite the delay. In 2013, petitioners presented evidence to the Commission that the proposer had sold their interest in the project to an out-of-state company, that the financing and turbine purchase agreements had fallen through, and that the project was clouded by litigation.[92] In light of this evidence, the Commission used its § 216B.25 powers to reopen the Certificate of Need in order to collect more information from the proposers. Ultimately, the Commission decided to allow the Certificate of Need to expire rather than allowing an extension.[93]

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[89] *Id*.
[90] *Id*.
[91] Minn. Pub. Utils Comm'n, *In the Matter of Awa Goodhue Wind, Llcs Application for A Certificate of Need for A 78 Mw Wind Project & Associated Facilities in Goodhue Cty.*, Order Reopening Case Under Minn. Stat. § 216B.25, Setting Procedures, and Requiring Filings, Docket No. IP-6701/CN-09-1186, 2-3 (Mar. 20, 2013).
[92] *Id*.
[93] Minn. Pub. Utils Comm'n, *In the Matter of Awa Goodhue Wind, Llcs Application for A Certificate of Need for A 78 Mw Wind Project & Associated Facilities in Goodhue Cty.*, Order Accepting Withdrawal, Revoking Site Permit, and Closing Dockets, Docket No. IP-6701/CN-09-1186, 2-3
(Oct. 23, 2013).

The Commission has also used its § 216B.25 powers to reopen matters when new regulatory and economic circumstances have undermined the prudence of the past decision. For example, in *Matter of Petition of Minnesota Power & Light Co.*,[94] Minnesota Power & Light made a deal to sell its interest in Boswell 3 to Northern States Power. In light of that deal, Minnesota Power was allowed to use the accounting mechanism "allowance-for-plant-being-phased-out" ("AFPO"). After that allowance, circumstances changed. Litigation and regulatory changes cast doubt over whether the sale would go through. Considering the changed circumstances, the Commission reopened and amended its accounting treatment of the AFPO credit.[95] CEOs have similarly presented compelling evidence of changed circumstances in this docket, discussed in Part II.E below, that cast a shadow on the prudence of Minnesota Power's investment in NTEC.

Thus, the Commission is not bound to approve the current plan, including NTEC, in the name of consistency with the AIAs. Section 216B.25 stands as additional evidence that the Legislature trusts the Commission to change decisions that no longer serve the public interest. Since the Commission is already obliged to assess this IRP according to a public interest standard under the planning laws,[96] § 216B.25 may be seen as additional authority the Commission can exercise in this docket to modify Minnesota Power's plan by excluding NTEC.[97]

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[94] Minn. Pub. Utils. Comm'n, *In the Matter of the Petition of Minnesota Power and Light Company, d/b/a Minnesota Power, for Authority to Change its Schedule of Rates for Retail Electric Service in Minnesota*, Order Approving and Clarifying AFPO Agreement, No. E-015/GR-87-223 (Sept. 8, 1989).
[95] *Id*. at 9.
[96] Minn. Stat. § 216B.2422, subds. 2, 4.
[97] The notice and opportunity to be heard requirements of § 216B.25 have already been satisfied in this docket. Minnesota Power had ample notice that its plan, including continued pursuit of NTEC, would be assessed based on whether it is "consistent with the public interest" under § 216B.2422. It had every opportunity to show that continued pursuit of NTEC was in the public interest, but it chose not to try to make that showing. Moreover, Minnesota Power has an opportunity to file a reply to this comment.

E. Circumstances Have Changed Dramatically Since NTEC Was Approved In 2018.

There have been major changes since 2018 relevant to the reasonableness of building NTEC. As Xcel Energy acknowledged in a recent IRP filing in which it explained why its previously-planned and legislatively-enabled Sherco combined cycle gas plant was no longer in the ratepayers' best interest, "the industry is currently in the midst of particularly accelerated change and to say the landscape is evolving quickly would be an understatement."[98] In fact, the industry is in the midst of an unprecedented transformation – a process of decarbonization that will only intensify in the years immediately ahead, as the industry is pushed to respond to what the Glasgow Pact called the need for "accelerated action in this critical decade."[99]

Moreover, given ongoing technological advances in carbon-free energy, combined cycle plants face a growing threat of becoming stranded investments. Indeed, Minnesota Power has already decided it wants much less of NTEC and its output than it wanted in 2018, effectively admitting that circumstances affecting NTEC have changed while failing to reflect that change in its IRP modeling or filing.

1. It is far more evident now than in 2018 that new gas plants are incompatible with the carbon cuts needed by 2030, especially when considering lifecycle emissions.

When the Commission voted 3-2 to approve the NTEC project in October of 2018, the need to stop building new gas plants like NTEC was far less evident than it is today. The IPCC 1.5°C Report had just been released earlier that month,[100] and its findings and their sweeping implications were not part of the record. Policymakers generally were not aware of the need to cut

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[98] Minn. Pub. Utils. Comm'n, *In the Matter of Xcel Energy's 2019-2034 Upper Midwest Integrated Resource Plan*, Xcel Energy Reply Comments, Docket No. E002/RP-19-368, 95 (June 25, 2021).
[99] Glasgow Pact, *supra* note 15, Part IV ¶ 18.
[100] IPCC 2018, *supra* note 12.

greenhouse gas emissions roughly in half by 2030. Policymakers also were not yet aware of the need to achieve roughly 80% decarbonization from the power sector by 2030 and approach complete decarbonization of the power sector by 2035, as the multiple pathway studies discussed in Part I establish and as the Biden Administration has endorsed. And the pathway studies had not yet firmly established the importance of stopping the construction of new gas plants lacking carbon capture if we hope to meet the 1.5°C target.

The record on which the Commission approved NTEC in 2018 also did not reflect recent advances in our scientific understanding of the damage caused by upstream methane emissions associated with gas production and transmission (an issue discussed more in Part VII.C.3). The Commission recently acknowledged the importance of upstream methane emissions when it ordered Xcel to include information about them in its annual performance-based ratemaking reports.[101] And the recently-adopted Natural Gas Innovation Act requires the Commission to consider upstream methane emissions when comparing gas consumption to alternative energy options.[102] The additional climate impact caused by upstream methane leakage matters; the attached PSE Report finds that including lifecycle methane emissions in addition to direct CO_2 emissions increases NTEC's climate impact by 92% over a 20-year time period.[103] The science, modeling, policies, and politics around climate change, around the power sector, and around gas plants are therefore undeniably different than they were in 2018. This alone undermines any contention that the question of whether continued pursuit of NTEC is in the public interest can be ignored in this proceeding.

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[101] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Order Accepting Report and Setting Additional Requirements, Docket No. E-002/CI-17-401, 5 (Feb. 9, 2022).
[102] Minn. Stat. § 216B.2427, subd. 2(a)(3).
[103] PSE Report at Section 3.4.

2. Investments in combined cycle gas plants are already at risk of being stranded, and that risk keeps growing.

The financial case for combined cycle plants like NTEC has eroded substantially since the plant's initial approval, largely due to cost and performance advances by renewable energy and batteries. Major new analyses show that many existing CC plants in the U.S. already face the prospect of early closure, unable to recover even their *operating* costs in the energy market, let alone their initial investment costs. Economic trends mean these financial risks will persist even without new decarbonization policies. It is not surprising, therefore, that over half of proposed CC plants scheduled to come online in 2019 and 2020 were canceled prior to construction.[104] As it happens, the Commission's 2018 vote on NTEC occurred at the very peak of the recent gas rush, with new CC capacity additions plummeting from 22 GW in 2018 to only 9 GW in 2019 and 4 GW in the first nine months of 2021.[105]

Three analyses of recent and projected U.S. investment in gas plants, all published in 2021, spotlight the growing financial hazards faced by these investments, especially for CC plants. The newest, from Rocky Mountain Institute ("RMI"), presents the results of extensive modeling comparing the costs and benefits of nearly every proposed gas plant in the U.S. with a clean energy portfolio (combining renewables, storage, demand response, and energy efficiency) that could provide the same grid services.[106] The RMI analysis finds in its base case analysis, which uses conservative assumptions about both renewable energy costs and gas costs, that 90% of proposed CCs could be economically avoided using clean energy portfolios.[107] If renewable energy prices

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[104] Lauren Shwisberg, et al., *Headwinds for US Natural Gas Power: 2021 Update on the Growing Market for Clean Energy Portfolios*, Rocky Mountain Institute, 14 (Dec. 2021), *available at* https://rmi.org/report-release-headwinds-for-us-gas-power/ [hereinafter "RMI Report"].
[105] *Id*. at 13.
[106] *Id*. at 3.
[107] *Id*. at 26.

fall at a somewhat faster rate than the base case assumes (more comparable to price declines in recent years) or if projected gas prices are 22% higher, clean energy portfolios outcompete 96-98% of the proposed CCs.[108]

However, the economic risk is not merely that better and cleaner investments could have been made; it is that just the operating costs of proposed CC plants will exceed the full levelized costs of building new clean energy alternatives, forcing the plants to either operate at a loss or retire years early and making it impossible to recover the initial investment in them in energy markets.[109] Another analysis, published in October 2021 by the financial think tank Carbon Tracker, similarly highlights this risk. It bluntly warns that *all* of the gas plants planned in the unregulated grid areas of the U.S. "will be unable to recover original investment, even if allowed to run for full planned lifetimes," putting some $24 billion at risk.[110] The Carbon Tracker analysis focuses on unregulated markets because it is aimed at private investors, but its warnings are clearly relevant to regulators assessing the prudence of new gas investments by regulated utilities.

Indeed, it appears that many of the gas plants in service in the U.S. are already operating at a loss, unable to compete with renewables in the market. The Carbon Tracker analysis finds that 31% of gas plant capacity operating in the U.S. "is already unprofitable to operate according to our models."[111] A third analysis published in August 2021 by S&P Global Market Intelligence

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[108] *Id*. at 34-35.
[109] *Id.* at 44.
[110] J. Sims, et al., *Put Gas on Standby: Unabated gas plants' future role in the power system should be predominantly limited to backup reserve to allow for flexible low carbon forms of supply to fully emerge*, Carbon Tracker, 3 (Oct. 2021)*, available at* https://carbontracker.org/reports/put-gas-on-standby/ [hereinafter "Carbon Tracker Report."].
[111] *Id*. at 22.

warns that some $34 billion worth of U.S. investment in recently-built combined cycle gas plants is already at risk of being stranded.[112]

None of these risk assessments reflects any costs from future assumed decarbonization policies; rather, they are based on current policies and market conditions.[113] More aggressive decarbonization policies – either new restrictions on carbon or additional support for carbon-free alternatives – would amplify the financial risk faced by gas plants.

These analyses do reflect the enormous long-term cost reductions of wind, solar, and batteries, which have already fundamentally transformed power-sector economics. Since 2009, solar photovoltaic ("PV") panel costs have fallen 90% and wind turbine costs have dropped 71%; just since 2013 battery costs have fallen 80%.[114] Long-term cost reductions in these technologies are expected to continue even without new policies as, for example, wind turbines get larger and more efficient,[115] and as solar power and batteries continue to evolve.

And there may well be major breakthroughs in battery technology, like the iron-based batteries being developed by Form Energy. That breakthrough is expected to extend battery life from a typical 4-6 hours today to a game-changing 100 hours, with aims of reaching deployment at a fraction of the cost of today's lithium-ion batteries.[116] The first commercial deployment of this new battery, at a site in Minnesota, is expected to be complete by the end of 2023.[117]

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[112] Adam Wilson & Steve Piper, *A nationwide push for green energy could strand $68B in coal, gas assets*, S&P Global Market Intelligence, 2 (Sept. 6, 2021), *available at* https://www.mncenter.org/sites/default/files/permalinks/A_nationwide_push_for_green_energy_coul...pdf [hereinafter, "S&P Report"].

[113] RMI Report at 30 (listing six economic and policy risks, but not including carbon policies); Carbon Tracker Report at 24; S&P Report at 9.

[114] Orvis, 2021 at 1 (citing cost figures from Lazard and Bloomberg NEF).

[115] Ryan Wiser, et al., *Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050,* Nature Energy, 559 (May 2021), *available at* https://www.nature.com/articles/s41560-021-00810-z.

[116] Russell Gold, *Startup Claims Breakthrough in Long-Duration Batteries*, Wall Street Journal (July 22, 2021), *available at* https://www.wsj.com/articles/startup-claims-breakthrough-in-long-duration-batteries-11626946330.

[117] Great River Energy, *Long-duration battery project in the works* (June 17, 2020), *available at* https://greatriverenergy.com/long-duration-battery-project-in-the-works/.

There have been recent interruptions in the long-term trend of falling costs for renewables and storage, though these cost challenges must be viewed in light of the extreme price volatility in gas prices in 2021 and 2022 and impacts on all segments of energy generation.[118] Continued U.S. export growth in liquified natural gas ("LNG") can be expected to continue to put upward pressure on domestic natural gas prices.[119] Despite the recent increase in renewable costs in some places, the fundamental forces driving the long-term decline in the costs of these technologies, including technological advances and economies of scale, should be expected to continue.[120]

And, governments around the world, including the Biden Administration, are getting far more aggressive in pushing for ways to reduce the costs of renewable energy and storage. The U.S. Department of Energy ("DOE") has launched a program to drive the cost of long-duration storage down by 90% below the cost of today's lithium-ion batteries by 2030, directing the experts at its national laboratories to focus on the challenge.[121] The DOE is also working to cut utility-scale solar power costs even further, down to 2.0 cents/kWh by 2030.[122] Expanding support for research and deployment of clean technologies faces fewer political barriers than direct efforts to regulate carbon emissions, as shown by last year's infrastructure bill which makes a historic federal investment in clean energy, including by expanding transmission and improving the battery supply

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[118] *See* Energy Information Administration, Henry Hub Natural Gas Prices, *available at* https://www.eia.gov/naturalgas/weekly/#tabs-prices-1.

[119] Marwa Rashad, *U.S. LNG exporters emerge as big winners of Europe natgas crisis*, Reuters (March 9, 2022) *available at* https://www.reuters.com/business/energy/us-lng-exporters-emerge-big-winners-europe-natgas-crisis-2022-03-09/.

[120] *See* National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB), *available at* https://atb.nrel.gov/electricity/2021/index.

[121] Brad Plumer, *Energy Department Targets Vastly Cheaper Batteries to Clean Up the Grid*, New York Times (July 14, 2021), *available at* https://www.nytimes.com/2021/07/14/climate/renewable-energy-batteries.html.

[122] U.S. Department of Energy, *Investing in a Clean Energy Future: Solar Energy Research, Deployment, and Workforce Priorities*, Issue Brief, 4 (Aug. 2021) *available at* https://www.energy.gov/sites/default/files/2021-08/investing-in-a-clean-energy-future-solar-energy.pdf [hereinafter "DOE Issue Brief"].

chain.[123] Thus, even if more ambitious carbon regulations are delayed, we can expect the intensifying focus on advancing renewables and storage by both governments and markets to further undercut the economics of new gas plants.

Even with Minnesota Power now owning only 20% of NTEC, it still faces significant risk if the plant is forced to retire early. If, for example, NTEC has to retire by 2035 (in compliance with Biden administration's announced goal of a carbon-free grid by that year), the EFG Report shows that **[TRADE SECRET BEGINS…** …**TRADE SECRET ENDS]** of Minnesota Power's investment in NTEC would be stranded.[124] And it is unreasonable to assume this loss could be avoided by retrofitting the plant to capture its carbon or to burn hydrogen. Both options are largely theoretical at this point, but would be quite costly, and those costs have not been reflected in Minnesota Power's modeling of NTEC. Moreover, both options would require the construction of entirely new systems of infrastructure – to carry away and sequester the CO2 or to make and deliver the hydrogen.

The risk that Minnesota ratepayers will suffer losses if NTEC cannot economically compete is made even greater by the fact that it will now be owned by three separate utilities, each in a different state and subject to different state regulatory authorities. This could limit Minnesota Power's ability to respond to the changing economics around gas generation and effectively cut its losses. As the Commission has seen regarding Otter Tail Power's co-ownership of the Big Stone and Coyote plants, when a Minnesota utility commits to a plant that is co-owned with utilities in different states, it can constrain the utility's and this Commission's ability to determine how much

[123] White House, *Fact Sheet: The Bipartisan Infrastructure Deal Boosts Clean Energy Jobs, Strengthens Resilience, and Advances Environmental Justice* (Nov. 08, 2021) a*vailable at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/08/fact-sheet-the-bipartisan-infrastructure-deal-boosts-clean-energy-jobs-strengthens-resilience-and-advances-environmental-justice/ [hereinafter, White House Infrastructure Fact Sheet].
[124] EFG Report, Technical Appendix. This estimate assumes NTEC begins operation in 2027.

the plant should run and when it should be retired. [125] This puts Minnesota ratepayers at extra risk of having to continue to pay for power that is both uneconomic and inconsistent with Minnesota's environmental goals.

3. The sale of most of Minnesota Power's share of NTEC is a substantial change since 2018, and it undermines the modeling on which MP's plan is based.

In its September deal with Basin Electric Power Cooperative, Minnesota Power's affiliate South Shore Energy LLC reduced its ownership share of NTEC from 50% to 20%.[126] In other words, whereas Minnesota Power and its parent, Allete, considered 50% ownership of NTEC to be attractive a few years ago, they no longer do. The arguments they used to convince the Commission to approve a 50% stake in the plant are no longer convincing to Minnesota Power and its affiliates themselves. And Minnesota Power stated in its response to CEOs' information request that, while it is delaying renegotiation of its AIAs regarding NTEC, it currently intends to take only 20% of NTEC's output, rather than 50%.[127] In other words, the economic case supporting NTEC has changed so much that Allete now wants to own much less of it, and Minnesota Power intends to use much less of its capacity and energy.

This strongly suggests that Minnesota Power and Allete have been internally reassessing the value of NTEC, and they decided it is of less value to them. We commend this reconsideration, which prudent utilities must do when circumstances change. However, Minnesota Power nowhere acknowledges this change in its IRP, or explains why it still believes it is prudent to commit to buying 20% of the project's energy and capacity rather than none of it.

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[125] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities,* Minn. Pub. Utils. Comm'n, Docket No. E999/CI-19-704.
[126] ALLETE Press Release, *supra* note 78.
[127] Minnesota Power Response to CEO IR 077, Docket No. E015/RP-21-33 (Dec. 13, 2021).

It is troubling to note that this change was in no way informed by Minnesota Power's EnCompass modeling. According to its responses to CEOs' information requests, Minnesota Power did not conduct any modeling runs that allowed the model to select NTEC (NTEC was forced into the model's selected plan), nor any that considered allowing the model to purchase less than 50% of NTEC's output.[128] This raises a threshold question of why such a major resource decision was not informed by Minnesota Power's resource planning modeling, or indeed by this ongoing resource planning proceeding. What is the purpose of this tool and this planning process if not to inform such major resource choices?

Clearly, the modeling Minnesota Power has presented to support its IRP no longer represents reality or its current intentions. As such, its modeling should not be used as a basis for approving Minnesota Power's IRP, at least with respect to NTEC, and the Commission's previous decision approving NTEC cannot substitute for Minnesota Power's and the Commission's obligation to examine the reasonableness of the project under current circumstances.

III. CEOS' ENCOMPASS MODELING SHOWS THAT CEOS' PLAN WITHOUT NTEC IS A BETTER OPTION THAN MINNESOTA POWER'S PREFERRED PLAN

CEOs' EnCompass modeling, which is based on the Company's modeling but uses updated information and corrections to flaws in Minnesota Power's assumptions, found that a generation resource expansion plan without NTEC and with more wind, solar, and battery storage is essentially equivalent in cost to Minnesota Power's Preferred Plan. Moreover, given the financial and policy risks presented by a new combined-cycle gas plant, NTEC's misalignment with national decarbonization pathways, and Minnesota policy preferences, the CEO Preferred Plan – detailed

[128] Minnesota Power Response to CEO IR 056, 071, 075, Docket No. E015/RP-21-33 (May 24, 2021; Oct. 18, 2021; Dec. 13, 2021).

in this section – is more squarely aligned with Minnesota law, policy, and in the public interest than Minnesota Power's Preferred Plan.

CEOs retained Energy Futures Group ("EFG"), with additional support from Applied Economics Clinic, to analyze the Company's EnCompass generation capacity expansion modeling and to conduct additional modeling on CEOs' behalf. Energy Futures Group and Applied Economics Clinic's analysis and findings are provided in a separate report in Attachment 1 ("EFG Report").

To develop the CEO Preferred Plan, our experts undertook a two-step process. First, they analyzed Minnesota Power's EnCompass assumptions and modeling and made changes to them based on updated information and corrected errors. Using these changes and corrections, EFG ran EnCompass to develop an optimal resource plan that meets the same energy and capacity requirements that Minnesota Power modeled. This plan was dispatched against the same 8760 hourly, chronological profile that the Company used in order to demonstrate that load can be met throughout all years of the planning period. That optimal generation resource expansion plan is referred to as the CEO Preferred Plan.

Then, in order to have an apples-to-apples cost comparison, while updating the modeling to reflect Minnesota Power's 20% NTEC share, EFG ran EnCompass to create an optimal plan with CEOs' changes to modeling cost inputs but including specific thermal resources that are in Minnesota Power's Preferred Plan – namely, NTEC and Hibbard. This is referred to as "Revised MP Preferred Plan" and is presented in the report as a fair and reasonable way to compare the CEO Preferred Plan with Minnesota Power's Preferred Plan.

The changes and corrections to Minnesota Power's modeling assumptions are explained in full detail in Section 1 of the EFG Report, and material changes can be summarized as follows:

- **NTEC**. After Minnesota Power filed its resource plan, the Company announced that it had sold a majority of its portion of NTEC, reducing its share from 50% to 20%. While the Company declined to update its modeling to incorporate this change,[129] EFG included Minnesota Power's new ownership and output share in the Revised MP Preferred Plan for purposes of comparison with the CEO Preferred Plan.[130] The CEO Preferred Plan does not include NTEC and therefore allows a comparison of NTEC to other resource options.[131]

- **Retires Hibbard in 2023**. For the CEO Preferred Plan, EFG set Hibbard – a 44 MW coal and biomass plant – to retire at the end of 2023.[132] As described in more detail in Part VIII of these comments, the PSE Report, Attachment 3, found that Hibbard has significant human health impacts and that these impacts are disproportionately affecting low-income and BIPOC populations.[133] Therefore, the CEO Preferred Plan retired the plant as soon as practicable.[134]

- **Solar-Battery Hybrids**. MP's modeling did not include solar-battery hybrids as a resource option. EFG allowed the model to choose solar-battery hybrids as an option in both the CEO Preferred Plan and the Revised MP Preferred Plan scenarios.[135]

- **Wind, Solar, Battery, Energy Efficiency, and Externality Assumptions**. EFG updated a number of inputs for wind, solar, and battery projects that affected the total assumed costs for those resources in the model.[136] These changes include Investment Tax Credit updates,[137] battery storage size options,[138] updated capital cost information,[139] availability of power purchase agreements,[140] and solar locations and capacity factors.[141] For energy efficiency, EFG modeled a higher level of energy efficiency than MP's base case and, unlike the Company, assumed that Minnesota Power's energy efficiency savings will continue beyond 2029.[142] This energy efficiency level was provided by Minnesota Power and based on the state's Demand Side Management Potential Study. Finally, EFG used

[129] EFG at Section 1.1.1.
[130] *Id.* at Section 1.1.1. NTEC was modeled at a 20% ownership share for Minnesota Power in the Revised MP Preferred Plan scenario.
[131] *Id.* at Section 2.
[132] *Id.* at Section 1.1.7.
[133] *See* Part VIII.
[134] *See* EFG at Section 3.2.
[135] *Id.* at Section 1.1.4.5.
[136] *Id.* at Section 1.1.4.
[137] *Id.* at Section 1.1.4.2.
[138] *Id.* at Section 1.1.8.
[139] *Id.* at Section 1.1.4.1.
[140] *Id.* at Section 1.1.4.3.
[141] *Id.* at Section 1.1.4.4.
[142] *Id.* at Section 1.1.6.

Minnesota's "High" value for both pollution externality costs and CO_2 regulatory costs, while Minnesota Power assumed the "mid" costs.[143]

- **Boswell 3 Retirement Transmission Upgrade**. For the Boswell units, Minnesota Power set up the EnCompass modeling with a constraint that required the model to choose a combination of new gas plants and/or large transmission line upgrades when either Boswell 3 or 4 are retired.[144] For example, if the modeled scenario included a Boswell 3 retirement, then EnCompass had to choose between either a large transmission line investment or a new combustion turbine ("CT"). If Boswell 4 were retired, EnCompass would have to select either a transmission upgrade, a CC, or two CTs to replace Boswell 4. Minnesota Power included this constraint to account for reliability issues it believes will need to be addressed when the Boswell units are retired.[145] EFG did not remove this constraint, but modified it based on CEOs' expert Telos Energy's transmission system reliability power systems modeling, which is discussed in more detail below in Part IV. EFG used a lower cost assumption than Minnesota Power for the level of transmission system upgrades that will be required to reliably retire Boswell 3 by 2030.[146] Telos Energy's analysis found that "[r]etirement of Boswell 3 will require some transmission reinforcements, but probably fewer than MP has proposed. Our analysis finds that MP's proposed transmission upgrades like the [**TRADE SECRET BEGINS… … TRADE SECRET ENDS**] would be sufficient mitigation when applied in conjunction with the CEOs' Preferred Plan generation additions."[147] As such, EFG modeled the transmission mitigation cost at the level of Minnesota Power's proposed [**TRADE SECRET BEGINS… … TRADE SECRET ENDS**].[148]

- **Demand Response Modeling Glitch**. Minnesota Power's modeling included a resource option of 100 MW of new demand response ("DR"), which the model selected as an optimal resource in the modeling runs developing the CEO Preferred Plan.[149] However, when examining the hourly dispatch of those modeling runs, EFG found that the DR resource option was not following the operational characteristics that MP developed. Specifically, the resource was violating both the maximum annual energy and the maximum consecutive energy amounts that the DR was supposed to have by operating at over 600 hours per year and for longer than 12 consecutive hours.[150] EFG attempted to

[143] *Id.* at Section 1.1.3.
[144] *Id.* at Section 1.1.2.
[145] Minnesota Power Response to CEO IR 027, Docket No. E015/RP-21-33 (Apr. 5, 2021). MP states that its analysis shows "a need for power formerly produced locally by dispatchable baseload generators on the Minnesota Power system in Northern Minnesota to be delivered from new sources when BEC units 3-4 are retired. This replacement power can be supplied locally from new dispatchable generation resources or it can be delivered from remote resources on the regional transmission network.")
[146] EFG at Section 1.1.2.
[147] Telos at Section 7.2.
[148] EFG at Section 1.1.2.
[149] *Id.* at Section 1.1.10.
[150] *Id.*

correct the issue with the EnCompass model vendor, but currently EnCompass does not have the combination of inputs needed to remedy the issue.[151] EFG therefore removed the DR resource as an option for the CEO modeling, despite EFG's analysis that this type of DR would likely provide benefits to Minnesota Power's system. Instead, EFG replaced the DR that was being selected by the model with a 100 MW 10-hour battery storage resource and 100 MW of wind, both being added in 2030.[152] This choice was made because EFG determined that "[t]hese two resources are comparable projects to add in place of the demand response project, given the timing of when EnCompass tended to dispatch the demand response project as well as the fact that it seemed to prefer a relatively long duration of dispatch."[153]

Using the changes and corrections to Minnesota Power's EnCompass modeling assumptions, EFG developed an optimal resource plan that meets the same energy and capacity requirements that the Company modeled and provides energy to meet Minnesota Power's load for the load shape they provided, which accounts for all hours of the year throughout all years of the planning period. That plan, which we refer to as the CEO Preferred Plan, replaces NTEC, Hibbard, and Boswell 3 with a combination of wind, solar, storage, and energy efficiency, and does not add any new fossil fuel generation. The generation capacity additions in the CEO Preferred Plan through the planning period include 700 MW of solar, 500 MW of wind, 184 MW of 4-hour battery storage, and 100 MW of 10-hour battery storage, as shown in Figure 1.[154] The specific type and timing of generation resources is provided in Table 1.[155]

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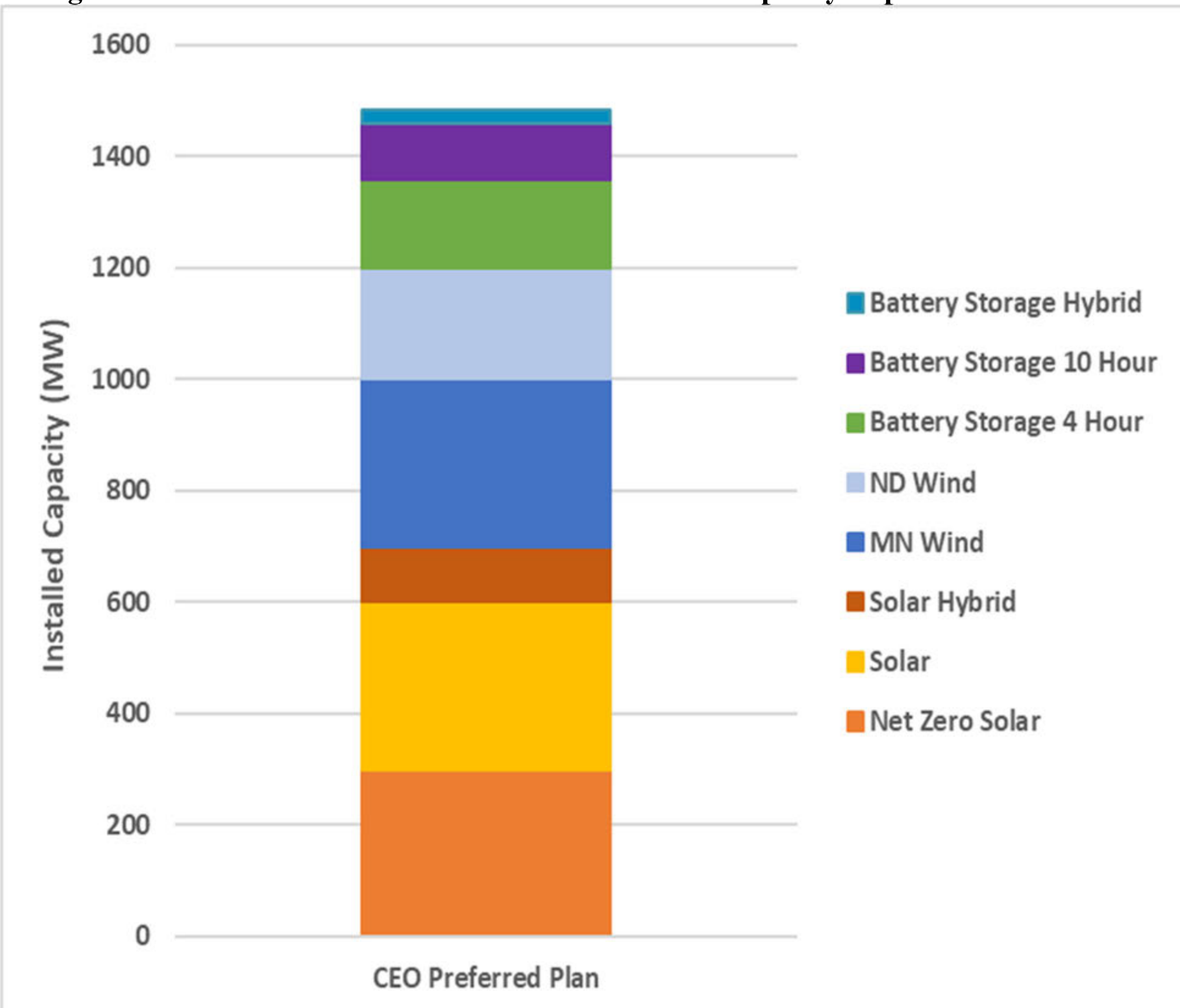
[151] *Id.*
[152] *Id.* at Section 1.1.11.
[153] *Id.* Section 1.1.11.
[154] *See* EFG at Section 3.1.
[155] *Id*.

Figure 1. CEO Preferred Plan Generation Resource Capacity Expansion Additions[156]



[156] *Id*.

Table 1. CEO Preferred Plan Annual Capacity Additions (MW ICAP)[157]

New Resource Additions:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Net Zero Solar	0	200	100	0	0	0	0	0	0	0	0	0	0
Solar	0	0	300	0	0	0	0	0	0	0	0	0	0
MN Wind	0	0	0	0	0	0	0	200	0	0	0	0	100
ND Wind	0	0	0	0	0	0	100	100	0	0	0	0	0
Battery Storage 4 Hour	0	0	0	0	0	0	0	143	0	0	0	0	16
Battery Storage 10 Hour	0	0	0	0	0	0	0	100	0	0	0	0	0
Solar Hybrid	0	0	0	0	0	0	0	100	0	0	0	0	0
Battery Storage Hybrid	0	0	0	0	0	0	0	25	0	0	0	0	0
Energy Efficiency		2	4	5	7	9	11	11	11	11	11	11	11
Retirements:													
Hibbard	-44												
Boswell 3							-350						

In the near-term (before 2030), the CEO Preferred Plan adds 600 MW of solar and 100 MW of wind. Then, in 2030, once Boswell 3 retires, it adds more wind, stand-alone storage, and solar-battery hybrids. In comparison, Minnesota Power's Preferred Plan's near-term additions are 200 MW of wind, 296 MW of NTEC, and 200 MW of solar when Boswell 3 retires.[158]

Table 2. MP Preferred Plan Annual Capacity Additions (MW ICAP)

New Resource Additions:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Net Zero Solar	0	0	0	0	0	0	0	200	0	0	0	0	0
MN Wind	0	0	200	0	0	0	0	0	0	0	0	0	0
NTEC Share	0	0	296	0	0	0	0	0	0	0	0	0	0
Retirements:													
Boswell 3							-350						

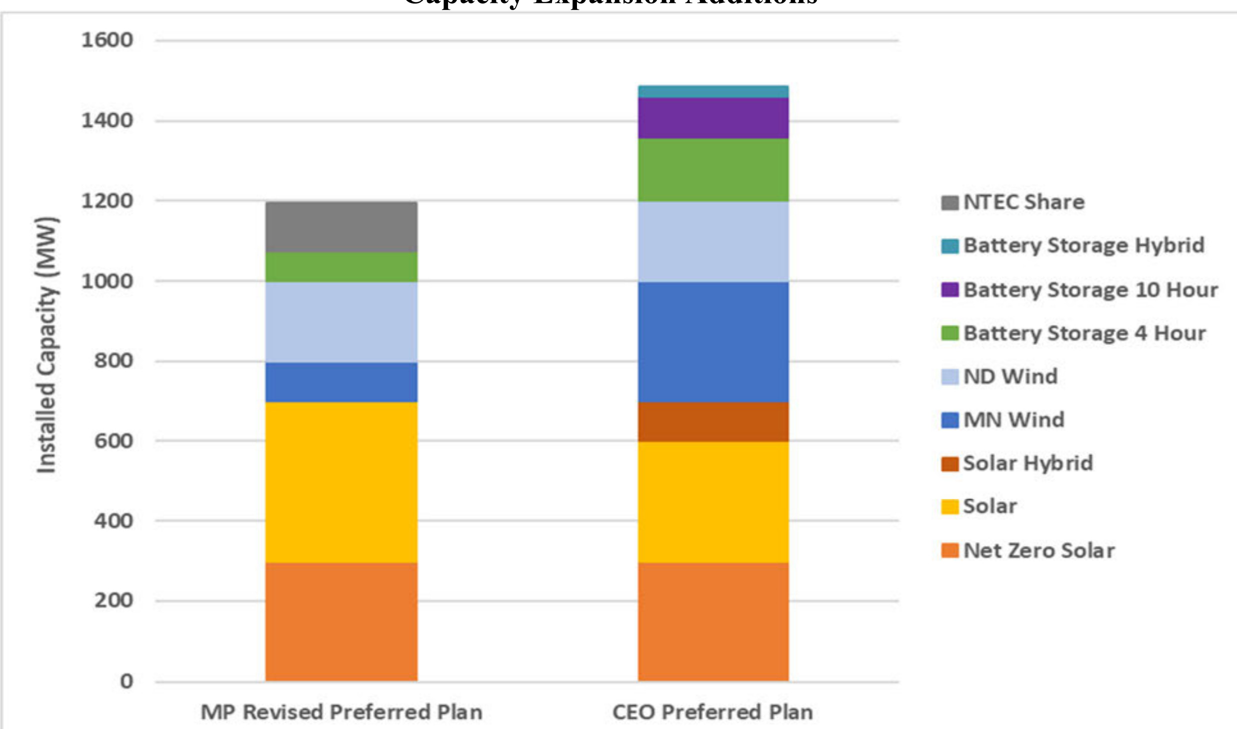
[157] *Id.*

[158] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, Initial Filing, Docket No. E015/RP-21-33, 66-68 (Feb. 1, 2021) [hereinafter "MP IRP"].

EFG compared the CEO Preferred Plan to the Revised MP Preferred Plan. As a reminder, the Revised MP Preferred Plan is a scenario in which all of the CEO modeling assumption cost and input changes are applied, but key elements of MP's Preferred Plan are included – namely, NTEC (at 20% ownership) and Hibbard. However, because of Hibbard's relatively small size, the overriding difference between the CEO Preferred Plan and the Revised MP Preferred Plan is NTEC. As shown below in Figure 2, the CEO Preferred Plan has more wind, solar, storage and the Revised MP Preferred Plan has fewer of those resources and NTEC.

EFG found that, compared to the Revised MP Preferred Plan, the CEO Preferred Plan has very similar, albeit slightly lower, costs and has fewer CO_2 emissions.[159]

Figure 2. Revised MP Preferred Plan and CEO Preferred Plan Generation Resource Capacity Expansion Additions[160]



[159] EFG at Section 3.2-3.3.
[160] *Id.* at Section 3.1.

This is the apples-to-apples comparison scenario that was developed to more accurately compare costs between the CEO Preferred Plan and the MP Preferred Plan by using the same cost assumptions (such as CEOs' updated solar capital costs), while maintaining the key differences between the plans, particularly MP's inclusion of NTEC. Table 1 shows the costs in both Present Value of Societal Costs ("PVSC"), which includes externality costs, and Present Value of Revenue Requirement ("PVRR"), which does not include externality costs.

Table 3. PVRR and PVSC Results for CEO Modeling ($000) [161]

	Revised MP Preferred Plan	CEO Preferred Plan
PVRR	$6,402,903	$6,391,441
Externality Costs	$1,839,387	$1,849,611
PVSC	**$8,242,290**	**$8,241,052**

The CEO Preferred Plan is cost-equivalent, although marginally less expensive, in the apples-to-apples cost comparison to the Revised MP Preferred Plan. The CEO Preferred Plan also has lower CO_2 emissions than the Revised MP Preferred Plan with NTEC. [162]

Table 4. CO_2 Emission Comparison (Tons)[163]

Year	Revised MP Preferred Plan	CEO Preferred Plan
2021	5,538,719	5,569,799
2022	4,964,703	4,989,758
2023	4,460,408	4,499,462
2024	4,437,314	4,301,762
2025	1,851,215	2,153,912
2026	1,860,234	2,257,351
2027	2,098,749	2,483,209
2028	2,162,244	2,442,054
2029	2,100,623	2,111,941
2030	1,445,283	1,118,664

[161] *Id.* at Section 3.2.
[162] *Id.* at Section 3.3.
[163] *Id.* at Section 3.3.

Year	Revised MP Preferred Plan	CEO Preferred Plan
2031	1,351,279	1,031,120
2032	1,344,305	1,128,925
2033	1,368,242	1,089,725
2034	1,272,580	998,924
2035	1,300,535	962,104
Total	**37,556,432**	**37,138,708**

It is important to recognize that the climate benefits resulting from the CEO Preferred Plan are not fully reflected in the modeled CO_2 emissions. Minnesota Power has projected that the NTEC plant would have a minimum 40-year operating lifetime,[164] meaning that most of its CO_2 emissions would occur after 2035. This table therefore does not reflect most of the CO_2 reductions that come from *not* building NTEC under the CEO Preferred Plan.

The modeled CO_2 emissions also do not reflect the reduction in upstream methane emissions associated with not building NTEC, which the PSE report estimates would increase NTEC's climate impact by 92% over a twenty-year timeframe.[165] The Department of Commerce has rightly pointed out that these additional methane impacts should be considered in IRP analyses,[166] and as we noted in Part II.E.1, the importance of upstream methane emissions is now reflected in the lifecycle focus of the state's Natural Gas Innovation Act.[167] If NTEC's upstream methane emissions, along with the facility's emissions of nitrous oxide (another greenhouse gas), were accounted for, the total CO_2-equivalent emissions for NTEC would rise from 2.24 million to 4.8 million tons CO_2e annually when considering a 20-year horizon for methane. Assuming 20% ownership, Minnesota Power's NTEC share would be 960,000 tons CO_2e per year rather than the

[164] Minnesota Power's Response to DOC IR 001, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.
[165] PSE Report at Section 3.4.
[166] Comments of the Deputy Comm'ner, Minn. Dep't of Commerce, Div. of Energy Resources, Minn. Pub. Utils. Comm'n, Docket No. 19-369 (Feb. 11, 2021).
[167] Minn. Stat. § 216B.2427, subd. 2(a)(3).

448,000 tons CO_2e captured in the model.[168] If we multiply the difference (512,000 tons) by the years NTEC would operate, that represents over 5 million tons of additional CO_2e just during the scope of this IRP, and over 20 million tons of additional CO_2e if NTEC were to operate its intended 40-year lifetime. The PVSC of the Revised MP Preferred Plan would also increase commensurately.

Moreover, as discussed in Part V, keeping a 2030 retirement date for Boswell 4 as a future option is an important outcome of this resource plan. However, the CEO Preferred Plan does not model the early retirement of Boswell 4, because Minnesota Power does not model beyond 2035 and, therefore, does not develop a replacement portfolio for a 2035 Boswell 4 retirement date. If CEOs were to have modeled Boswell 4's retirement when Minnesota Power has not, it would prevent an apples-to-apples comparison that isolates the question of whether NTEC is in the public interest, which is the most imminent resource planning question facing Minnesota Power and the Commission.

EFG also performed sensitivity analyses on the CEO Preferred Plan to test MP's low load, high load, low gas price, high gas price, and higher gas price sensitivities.[169] Under these sensitivities, EFG redispatched both the CEO Preferred Plan and the Revised MP Preferred Plan (which includes NTEC at 20% ownership and Hibbard), in order to compare the resource expansion plans' costs in the different conditions.[170] As shown in Table 5, across all the sensitivities, the CEO Preferred Plan performs as well as the Revised MP Preferred Plan, with the CEO Preferred Plan slightly less expensive in three sensitivities and only marginally more

[168] PSE Report at Section 3.4.
[169] EFG at Section 3.4.
[170] *Id*.

expensive in two. This demonstrates that the CEO Preferred Plan is robust under varying conditions.

Table 5. PVRR and PVSC NPV Results for MP Defined Sensitivities ($000)

Revised MP Preferred Plan ($000)					
	Higher Gas	**High Gas**	**Low Gas**	**High Load**	**Low Load**
PVRR	$6,559,049	$6,507,445	$6,412,047	$6,729,602	$6,212,887
Externality	$1,853,225	$1,835,066	$1,848,781	$2,123,541	$1,659,805
PVSC	$8,412,273	$8,342,511	$8,260,828	$8,853,143	$7,872,691
CEO Preferred Plan ($000)					
	Higher Gas	**High Gas**	**Low Gas**	**High Load**	**Low Load**
PVRR	$6,503,941	$6,473,381	$6,423,085	$6,714,988	$6,197,756
Externality	$1,850,871	$1,851,573	$1,844,640	$2,108,737	$1,677,527
PVSC	$8,354,812	$8,324,955	$8,267,724	$8,823,726	$7,875,283
PVSC % Difference	**-0.68%**	**-0.21%**	**0.08%**	**-0.33%**	**0.03%**

Overall, CEOs' EnCompass modeling shows that the CEO Preferred Plan, which adds wind, solar and storage in place of NTEC and Hibbard, and does not add any new fossil fuel generation, is directly cost-competitive with the Revised MP Preferred Plan and has lower CO_2 emissions. Moreover, when considered in the context of the considerable financial, policy, and climate risk that comes from building a new combined-cycle gas plant, described extensively in previous sections, the CEO Preferred Plan is squarely in the public interest. Specifically, CEOs' EnCompass modeling demonstrates that the Commission should: 1) approve that MP retire Boswell 3 by 2030; 2) remove NTEC from the approved plan; 3) order Hibbard retired as soon as practicable; and 4) find there is a need for approximately 600 MW of solar by 2026.

IV. TELOS ENERGY'S TRANSMISSION RELIABILITY ANALYSIS SHOWS THAT NTEC IS NOT NEEDED ON GRID RELIABILITY GROUNDS

Minnesota Power has emphasized that retiring the Boswell units will require transmission system "mitigations" through new transmission, generation, operations, and/or other grid equipment like synchronous condensers, in order to maintain a stable transmission system in

Northern Minnesota.[171] To ensure that the CEO Preferred Plan will maintain a reliable transmission system given Boswell coal unit retirements, CEOs retained Telos Energy ("Telos") to analyze the transmission system-level reliability issues and solution options when one or both Boswell coal units are retired. Using the same software modeling tools and underlying system database as MISO and Minnesota Power, Telos found that: (1) Boswell 3 can retire reliably without the NTEC combined cycle plant, and (2) Minnesota Power must begin planning now in order to reliably retire Boswell 4 by 2035 or sooner.

As part of its analysis for transitioning from the Boswell units, Minnesota Power requested a MISO Y-2 Study in 2018. Minnesota Power explains that "[m]irroring the standard MISO generator retirement study (Attachment Y) process, the Attachment Y-2 Study was an information-only study of various scenarios to identify reliability issues due to the potential retirement of the BEC units."[172] This MISO Y-2 Study "concluded that robust mitigating solutions would likely need to be built before the retirement of the BEC units could be allowed."[173] To address these issues, CEOs retained Telos to examine transmission system impacts and solutions from retiring the Boswell units and to conduct modeling analysis, using the same approach, software type, and MISO database as those used by MISO in its Attachment Y and Y-2 study reliability analyses.[174] However, Telos' analysis modeled additional scenarios reflecting different regional generation resource additions consistent with the CEO Preferred Plan, including new wind, solar, and storage, and not including new fossil gas additions such as NTEC and the Sherco CC. Telos' full analysis is provided in detail in its "*Transmission Reliability Analysis of Minnesota Power's Integrated Resource Plan*" ("Telos Report" provided as Attachment 2).

[171] MP IRP, Appendix F at 40.
[172] *Id*. at 43.
[173] *Id*.
[174] Telos (Attachment 2) at Section 2.

Overall, Telos found that a scenario based on the CEO Preferred Plan "results in essentially equal, and often, better reliability" than a scenario based on MP's Preferred Plan.[175] More specifically, Telos' report highlights two central findings:

- **Boswell 3 can retire reliably without the NTEC combined cycle plant**. Telos found that retiring Boswell 3 will require transmission system mitigation solutions but that adding or removing NTEC has a negligible impact on reliability when Boswell 3 is retired. Regarding Boswell 3, Telos found that Minnesota Power's proposed transmission upgrades, like a **[TRADE SECRET BEGINS… … TRADE SECRET ENDS],** would be sufficient mitigation when applied in conjunction with new generation additions in Minnesota that are planned and consistent with the CEO Preferred Plan. Indeed, Telos found that reliability could be maintained with only a portion of the transmission upgrades Minnesota Power proposed, considerably lowering the costs associated with retiring Boswell 3.[176] The addition of NTEC, however, "does not provide a material transmission system-level reliability mitigation benefit and, in fact, creates thermal and voltage issues on MP's system in the vicinity of NTEC in the scenarios analyzed."[177] Therefore, Telos' analysis shows that CEO Preferred Plan without NTEC provides for the same level of transmission system reliability as Minnesota Power's Preferred Plan.

- **Minnesota Power must begin planning now in order to reliably retire Boswell 4 by 2035 or sooner**. Consistent with Minnesota Power's analysis, Telos found that retiring Boswell 4 in addition to Boswell 3 will increase stress on the system such that more extensive transmission mitigations will likely be required than when retiring Unit 3 alone.[178] These mitigations would almost certainly include transmission line additions, such as the current MISO Long Range Transmission Planning Iron Range line and potentially others.[179] However, Telos found that MP's estimates of the extent of the required transmission mitigation solutions are overestimated.[180] A major aspect of MP's overestimation is due to an unreasonably pessimistic assumption regarding power flows between Minnesota Power and Manitoba Hydro during winter peak conditions, which is discussed in more detail below in Part V.C.[181] Options such as contractual or operational solutions to prevent Minnesota Power from exporting maximum system power to Manitoba during Minnesota Power's highest peak times, therefore, could significantly reduce issues when Boswell 4 retires and lower mitigation needs and costs.[182] These types of contractual or operational solutions, in addition to other grid reliability options like synchronous condensers, could play a role in transmission additions as part of an optimal

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[175] Telos at Section 5.1.
[176] *Id.* at Section 7.2. As discussed in Section III above, based on Telos' analysis, Energy Futures Group used MP's proposed proxy **[TRADE SECRET BEGINS … …TRADE SECRET ENDS]** as the mitigation for Boswell 3's retirement in its EnCompass modeling for CEOs.
[177] *Id.* at Section 7.1.
[178] *Id.* at Section 7.3.
[179] *Id.* at Section 5.4.
[180] *Id.* at Section 5.4.
[181] *Id.* at Section 6.
[182] *Id.* at Section 6.

> solution set to reliably retire Unit 4. In order to do exactly this type of analysis, as well as begin transmission line and other mitigation solution investments, Telos found that "[p]lanning for mitigations and/or other solutions needs to start now, even to prepare for retirement of Boswell 4 in 2035, and certainly to preserve the option of earlier retirement."[183]

In addition to these core findings, Telos also studied a sensitivity that examined transmission system impacts of converting Boswell unit 3 to a synchronous condenser when it retires.[184] The results of the conversion showed significantly improved voltage support compared to both Minnesota Power's plan and CEOs' plan scenarios. Telos recommends this approach as a solution because of the reliability benefit and relatively low cost of the solution as a conversion utilizing existing grid infrastructure, rather than a fully new asset.[185]

Telos' conclusions that NTEC does not provide any material transmission grid-level reliability benefit in the context of the CEO Preferred Plan or Minnesota Power's Preferred Plan in conjunction with EFG's EnCompass modeling which showed that the CEO Preferred Plan without NTEC is a cost-effective and reliable alternative to Minnesota Power's Plan demonstrate that NTEC is not in the public interest. Moreover, Telos' analysis underscores the urgency for Minnesota Power to meaningfully plan for Boswell 4's retirement.

V. MINNESOTA POWER NEEDS TO BEGIN TO PLAN FOR THE EARLY RETIREMENT OF BOSWELL 4 NOW

A. Minnesota Power's Preferred Plan Lacks Any Steps That Would Enable The Utility To Actually Retire Boswell 4 In 2035, Even Though The Utility Claims It Will Be "Coal-Free" By That Year.

Minnesota Power prominently claims in the cover letter of its resource plan that its "2021 Plan [will]… result in a generation mix that is coal-free by 2035."[186] This claim is repeated several

[183] *Id.* at Section 7.3.
[184] *Id.* at Section 3.3.2.
[185] *Id.* at Section 3.3.2. Telos estimates that converting Boswell 3 to a synchronous condenser would cost between $8-20 million. Telos at Section 3.3.2, n.31.
[186] MP IRP, Cover Letter.

times in the resource plan, including the more specific claim that its Preferred Plan's "concrete steps" include "ceasing coal operations at Minnesota Power's Boswell Energy Unit 4 in 2035."[187] CEOs appreciate that Minnesota Power recognizes the need to retire Boswell 4. However, aiming for a 2035 Boswell 4 retirement date would still put Minnesota Power on a coal-retirement schedule five years behind where it needs to be for alignment with 1.5°C pathways. Moreover, Minnesota Power's plan does not actually achieve this 2035 retirement.

When CEOs requested that Minnesota Power identify the steps included in its Preferred Plan that would allow Minnesota Power to actually retire or refuel Boswell 4 by 2035, the utility could not identify a single one.[188] In other words, Minnesota Power's plan does not include the construction or purchase of any generation, transmission, or grid-strengthening resources that would allow Minnesota Power to replace the energy, capacity, or reliability services provided by Boswell 4. Minnesota Power stated in its response to CEOs that "[p]lans to replace the energy, capacity, and reliability services that are currently provided by Boswell Unit 4 are outside the timeframe of the current planning period."[189]

In fact, the stated retirement date is not outside the plan's timeframe; this resource plan goes through 2035, and Minnesota Power claims that its Preferred Plan includes concrete steps to cease coal use at Boswell 4 "in 2035."[190] However, even if Boswell 4's retirement were scheduled for just after the planning period, Minnesota Power repeatedly stresses that it will take ten years or more to complete the kind of large transmission project or large resource addition needed to replace Boswell 4.[191] These years of effort and their associated costs should certainly have been

[187] *Id*. at 3.
[188] Minnesota Power's Response to CEO IR 80, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[189] *Id.*
[190] MP IRP at 3.
[191] *See, e.g.*, MP IRP, Appendix P, at 4, 12, 30.

included in this IRP, and their absence is striking. Replacing Boswell 4 is the most difficult resource planning challenge Minnesota Power faces during the period of this IRP, yet its Preferred Plan completely evades it.

Indeed, Figure 17 of Minnesota Power's IRP shows its continued heavy reliance on coal in 2035. The utility currently depends on coal for over 800 MW of capacity, more than half its total capacity.[192] Under its Preferred Plan, Minnesota Power's dependence on coal capacity in 2035 would remain over 400 MW – from the unretired Boswell 4 unit – or close to 30% of its total capacity. Figure 18 of the IRP shows energy from coal actually increasing between 2031 and 2035.[193]

Under these circumstances, Minnesota Power's claim that its Preferred Plan "will result in the Company providing a power supply that is coal-free by 2035" is not reflected in its plan, either through modeling or other necessary planning. Minnesota Power may be *claiming* it will be coal-free by 2035, but it is not *planning* to be coal-free by that year.

B. Minnesota Power Has Failed To Comply With The Commission's Order To Include In This IRP An "Analysis That Thoroughly Evaluates And Includes A Plan For The Early Retirement" Of Boswell 4.

In its order approving NTEC, the Commission explicitly required Minnesota Power to include in this resource plan a "baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Minnesota Power's two remaining coal plants, Boswell 3 and 4, individually and in combination."[194] As discussed above, Minnesota Power's Preferred Plan fails to plan even the on-schedule retirement of Boswell 4 (at the end of 2035, when the unit will be 55

[192] MP IRP at 61.
[193] *Id*. at 62.
[194] AIA Approval, *supra* note 74, at 29.

years old and fully depreciated).[195] But Minnesota Power has also failed to include in its IRP, even among the rejected scenarios, anything that could be called a plan for Boswell's early retirement.

The Commission's order on this point is particularly important given that retiring the nation's coal plants by 2030 is a critical component of the several new studies charting a pathway to limit warming to 1.5°C. Boswell 4 emitted an average of over 3.5 million tons per year of CO_2 during 2018 to 2020,[196] and it is likely to become the state's largest carbon emitter by far after 2030, when Xcel's coal plants are retired.[197] Retiring Boswell 4 would also yield striking human health benefits. The unit is estimated to have caused over $50 million in health impacts in 2021, including causing up to 4.6 premature deaths that year, as CEOs discuss in Part VIII.[198] Every year's delay in retiring Boswell 4 perpetuates these enormous harms.

Minnesota Power indicates that its "Baseload Retirement Study" in Appendix P of its IRP represents compliance with the Commission's order requiring an analysis that thoroughly evaluates and includes a plan for the early retirement of Boswell 3 and 4.[199] However, Appendix P is not a plan for Boswell 4's early retirement; in fact, it reads more like a discussion of why Minnesota Power would rather *not* retire Boswell 4, repeatedly stressing how hard it will be to replace its grid-supporting services and how long it will take.[200] Minnesota Power also, in another IRP appendix, estimates that the transmission upgrades needed to retire Boswell 4 will cost from

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195 Boswell 4 will be fully depreciated by the end of 2035. MP IRP, Appendix P at 2.
196 PSE Report at Section 3.2.1, Table 1.
197 Based on data from EPA's Facility Level Information on Greenhouse Gases Tool (FLIGHT), *available at* https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal.
198 PSE Report at Section 3.2.2, Table 3. These health estimates are based estimated 2021 generation.
199 MP IRP, Appendix P, at 1.
200 Minnesota Power states that "in the event of BEC3 and 4 retirements, the evaluations indicate significant transmission investment and/or in-place dispatchable generation will be needed to serve regional reliability needs, and these solutions will likely require ten years or more to implement from the time a retirement decision is made." *Id*. at Appendix P, 12; *see also id.* at 17, 18, 30.

$0.5 to 1.3 billion,[201] a cost range so wide that it illustrates Minnesota Power's failure to thoroughly evaluate the needed upgrades. Moreover, Minnesota Power's IRP does not describe how it would replace Boswell 4's energy and capacity in this upgraded-transmission scenario, or estimate the cost of that replacement energy and capacity.

Minnesota Power does include one scenario in its Swim Lane comparison that purports to retire both Boswell 3 and 4 early, called the Expedited Retirement of BEC 3 and 4 scenario.[202] This scenario does not include the extensive transmission upgrades referenced in Appendix P; rather, it would avoid them by replacing Boswell 4 in 2031[203] with a new 593 MW combined cycle gas plant that lacks carbon capture. However, it is utterly unrealistic for Minnesota Power to assume the availability of this option. Building such a plant is already incompatible with the 1.5°C pathways (see Part I) and will be even more so in the future; indeed, the Biden Administration, consistent with the science and pathway studies, is aiming for a power grid that is carbon-free by 2035. This scenario for retiring Boswell 4, dependent upon an option virtually certain to be unavailable, also falls far short of the thorough evaluation and plan for Boswell's early retirement that the Commission ordered.

C. The Commission Should Order Minnesota Power To Start Planning The Transmission System Reliability Solutions Needed To Allow The Retirement Of Boswell 4 by 2030.

In the reply to CEOs' information request, Minnesota Power also stated, "[g]iven the 2021 IRP analysis supported no immediate action on Boswell Energy Center Unit 4, as outlined in the

[201] MP IRP, Appendix F, at 65.
[202] MP IRP at 49-50. The validity of the Swim Lane comparison is severely undermined by the fact that the Minnesota Power's Preferred Plan does not include any actual steps to retire Boswell 4, discussed in Part V.A, despite claims that the plan will lead to a coal-free system by 2035.
[203] The 2031 date is set forth in the text of MP IRP, Appendix K, at 15. By contrast, a graphic in the IRP suggests the CC plant would be added in 2029/2030. MP IRP, Figure 14, at 50. Both dates are implausible given the need for deep decarbonization by 2030 with the power sector in the lead.

Baseload Retirement Study and IRP analysis, replacement options and timelines for Boswell Unit 4 will be part of the next IRP."[204] Putting aside the surprising suggestion that a fifteen-year resource plan should only set forth "immediate steps," Minnesota Power is wrong in this claim too. In fact, its Baseload Retirement Study shows that Minnesota is *behind schedule* in taking the concrete steps needed to retire Boswell 4, at least if there is to be any realistic chance to retire it by 2030 in compliance with the 1.5°C pathway studies.

Specifically, in Minnesota Power's study of Boswell's retirement, it projects it "would take approximately ten years to implement improvements to the transmission system to accommodate a BEC 4 retirement."[205] This 10-year estimate is not casually asserted; it is stressed several times throughout the Appendices to the IRP.[206] The utility also stresses that Boswell 3 and 4 provide "essential reliability services" to the region.[207] Thus, rather than justifying Minnesota Power's choice to wait until the next IRP before actually planning Boswell 4's retirement, the utility's own analysis proves the urgency of moving forward responsibly right now to plan the transmission upgrades or other transmission reliability solutions needed to replace Boswell.

Minnesota Power based its estimate of how long construction of such a project would take upon its recent experience building the Great Northern Transmission Line.[208] That project involved years of what Minnesota Power calls "pre-planning" (from 2007 through 2011), followed by several years of additional planning, state and federal review, and design and permitting (2012 through 2016), followed by construction (2017 to mid 2020).

[204] Minnesota Power's Response to CEO IR 80, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[205] MP IRP, Appendix P, at 30.
[206] MP IRP, Appendix P at 4, 12, 17, 30; Appendix J at 21, 22.
[207] MP IRP, Appendix P, at 17.
[208] *Id.* at 31.

Given the need to retire all coal plants by no later than 2030 and given how long it could take to build the necessary transmission upgrades to allow Boswell's complete retirement, Minnesota Power certainly cannot wait until its next IRP to begin planning. If the next IRP is submitted in 2024 and approved in 2025 (a quicker schedule than usually applies to IRPs), the utility would only have five years or less to complete what it estimates is a ten-year project in order to keep a 2030 retirement as an option. By waiting until its next IRP, Minnesota Power would effectively be making it impossible to retire Boswell 4 in a well-planned way by 2030, at least if what Minnesota Power says regarding how long these upgrades will take proves to be true.

The Commission should therefore order Minnesota Power to begin planning the necessary transmission system reliability solutions now. The planning process should proceed at the pace and to the extent required to keep viable the option of retiring Boswell entirely by 2030. The Great Northern Transmission Line experience illustrates that there are years of planning and permitting work needed before construction commences. Given the reluctance Minnesota Power has shown to plan for Boswell's retirement, the Commission should also require Minnesota Power to file annual updates of its planning progress.

The process of seriously planning the transmission upgrades and other transmission system reliability solutions may reveal that Minnesota Power has overestimated the cost and extent of those upgrades. There is reason to expect that alternatives -- like synchronous condensers, operational adjustments, or contractual arrangements with Manitoba Hydro – could greatly reduce the cost of ensuring reliability upon Boswell 4's retirement. As the Telos Report explains, Minnesota Power's Beyond Boswell study assumes, without explanation, a huge power flow from Minnesota to Manitoba during the winter peak, and Minnesota Power requested that MISO make the same assumption in its Y2 study.[209] However, historically the flow of power during the winter peak is in the opposite direction, from Manitoba to Minnesota, as MISO assumes in its MTEP20 Winter Peak case.[210] As the Telos analysis shows, this single assumption of reversing the winter peak power flow significantly increases the projected reliability problems associated with retiring Boswell 4, and it may well have contributed to a substantial overestimate of the cost and difficulty of building the transmission upgrades needed to prepare for that retirement.[211] Minnesota Power's cost estimate may also be overstated because the utility has not studied promising cost-reducing options identified in the Telos Report, including converting the Boswell units to synchronous condensers and siting storage at critical locations.[212]

Finally, MISO has already included in its March 29, 2022 Long Range Transmission Planning (LRTP) Tranche 1 Portfolio a new power line identified as "Iron Range – Benton – Cassie's Crossing."[213] If built, this proposed line (estimated to cost $853 million)[214] would, according to the Telos Report, provide similar reinforcement to the transmission system as a line proposed by Minnesota Power to enable the retirement of Boswell 4.[215] MISO's Iron Range – Benton – Cassie's Crossing line could therefore greatly reduce the transmission upgrades that Minnesota Power alone would be responsible for.[216]

If Minnesota Power is right, and the needed transmission upgrades are as extensive and costly as it estimates in this IRP, it is critical to move ahead with planning them immediately.

[209] Telos at Section 3.3.4.
[210] *Id.*
[211] *Id.* at Section 7.4.
[212] *Id.* at Section 5.4.
[213] *LRTP Tranche 1 Portfolio Detailed Business Case,* MISO, LRTP Workshop, 42 (Mar. 29, 2022) *available at* https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.
[214] *Id.* at 13.
[215] *Telos* at Section 5.4.
[216] *Id.*

However, CEOs believe the planning process – which should begin now and not in the next IRP – is likely to identify more cost-effective options.

VI. THE COMMISSION SHOULD RECOGNIZE THAT MINNESOTA'S CARBON REGULATORY COST ESTIMATES DO NOT REFLECT THE FULL REGULATORY RISK AND SHOULD COMMENCE A PROCEEDING TO UPDATE THEM

The current estimate of the likely range of costs of future carbon regulation, adopted pursuant to Minn. Stat. § 216H.06, is outdated.[217] It does not reflect the material changes in climate science and policy or the far more aggressive decarbonization targets the power sector now faces, as discussed in Part I.A and I.B. The Commission should recognize the presence of this unaccounted-for regulatory risk in assessing this IRP. It should also commence a proceeding to update its carbon regulatory cost estimates to reflect today's climate policy landscape, as required by section 216H.06.

The Commission's most recently adopted CO_2 regulatory cost estimates still reflect the assumption that the only carbon regulatory cost faced by the power sector will be the requirement to pay a relatively modest cost per ton of carbon emitted under a cap-and-trade system aiming for economy-wide carbon cuts of around 80% over four decades.[218] For years that was a reasonable assumption, reflecting as it did the emission reduction schedule and regulatory mechanism then at the center of the state and federal debate. Today, however, both the reduction schedule and the expected regulatory mechanisms have changed.

[217] Minn. Pub. Utils. Comm'n, *In the Matter of Establishing an Updated 2020 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation under Minn. Stat. § 216H.06*, Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket No. E-999/DI-19-406 (Sep. 30, 2020).

[218] For example, the Waxman-Markey bill, which passed the U.S. House in 2009, sought an 83% reduction in economy-wide carbon emissions by 2050. *Waxman-Markey Short Summary*, Center for Climate and Energy Solutions (June, 2009) *available at* https://www.c2es.org/document/waxman-markey-short-summary/.

First, the power sector now faces the prospect of having to decarbonize 100% in 13 years rather than 80% in 40 years – a far steeper emission reduction trajectory. The goal of a carbon-free power sector by 2035 has been adopted by the Biden Administration.[219] At the state level, Minnesota's Governor Walz has announced his support for a carbon-free power sector by 2040, a goal nearly as ambitious as the Biden Administration's.[220] These more ambitious goals are part of a larger effort to limit warming to no more than the globally-embraced target of 1.5°C. The pathway studies discussed in Part I.B indicate that to achieve that target, the nation will likely need policies that will close existing coal plants by 2030 and prevent the building of new gas plants lacking carbon capture. The current carbon regulatory cost estimates do not reflect the costs of such policies, even at their upper range.

Second, cap-and-trade is no longer expected to be the sole or even primary regulatory mechanism to achieve the power sector's decarbonization.[221] Decarbonization of the power grid is now more widely expected to be driven by some mix of carrots and sticks. The carrots include more aggressive support of critical decarbonization technologies like renewable energy, energy storage, and related transmission, including the unprecedented investment in last year's infrastructure bill and over $500 billion in tax credits and other energy spending that appears to

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[219] White House Fact Sheet, *supra* note 18.
[220] Office of Governor Tim Walz and Lt. Governor Peggy Flanagan, *Governor Walz, Lt. Governor Flanagan, House and Senate DFL Energy Leads Announce Plan to Achieve 100 Percent Clean Energy in Minnesota by 2040* (Jan. 21, 2021) *available at* https://mn.gov/governor/news/?id=1055-463873.
[221] We note that if a carbon price alone were to drive decarbonization, the power sector could expect prices far higher than the current estimate of $5-25/ton; a recent analysis by Wood Mackenzie finds it would take carbon prices of $160/ton by 2030 to achieve greenhouse gas reductions in line with a 1.5 ° target. Wood-Mackenzie, *Significant Increase in Carbon Pricing is Key in 1.5-degree World*, (Mar. 4, 2021), *available at* https://www.woodmac.com/press-releases/significant-increase-in-carbon-pricing-is-key-in-1.5-degree-world/#:~:text=Wood%20Mackenzie's%20latest%20scenario%20report,to%20within%201.5%20degrees%20Celsius.

have sufficient support in Congress this year.[222] The sticks could someday include a Clean Energy Standard, but given that the standard that passed the House last year is now blocked in the Senate, the Biden Administration plans to adopt aggressive EPA rules to ensure the rapid reduction of power sector emissions to meet the 2035 deadline.[223]

No reasonable estimate of the range of future carbon regulatory costs faced by electricity generation can afford to ignore the reduction targets and policy steps currently at the center of the climate policy debate. Political delays in these policy efforts just make it likely that even steeper emission cuts will be required by the power sector in a few years. Climate change is not slowing, and the need is growing for accelerated decarbonization of the power grid in this decade and the next. Minnesota utilities cannot prudently make long-term investments if they fail to acknowledge the possibility that society, mobilizing in an unprecedented way against an unprecedented global danger, will actually do what is scientifically necessary, economically and technologically possible, and politically supported by the nation's and state's leadership.

We also note that the current approach to future carbon regulatory costs can lead to highly irrational outcomes when combined with the Commission's estimated environmental externality costs.[224] Once the carbon regulatory costs are presumed to begin in 2025, utilities are allowed to assume that the environmental costs of carbon emissions disappear. The Commission's current estimate of carbon regulatory costs for 2025 ($5-25/ton) is much lower than its estimate of carbon environmental costs for 2024 ($9.87-46.06/ton). Thus, the portion of the total social cost associated

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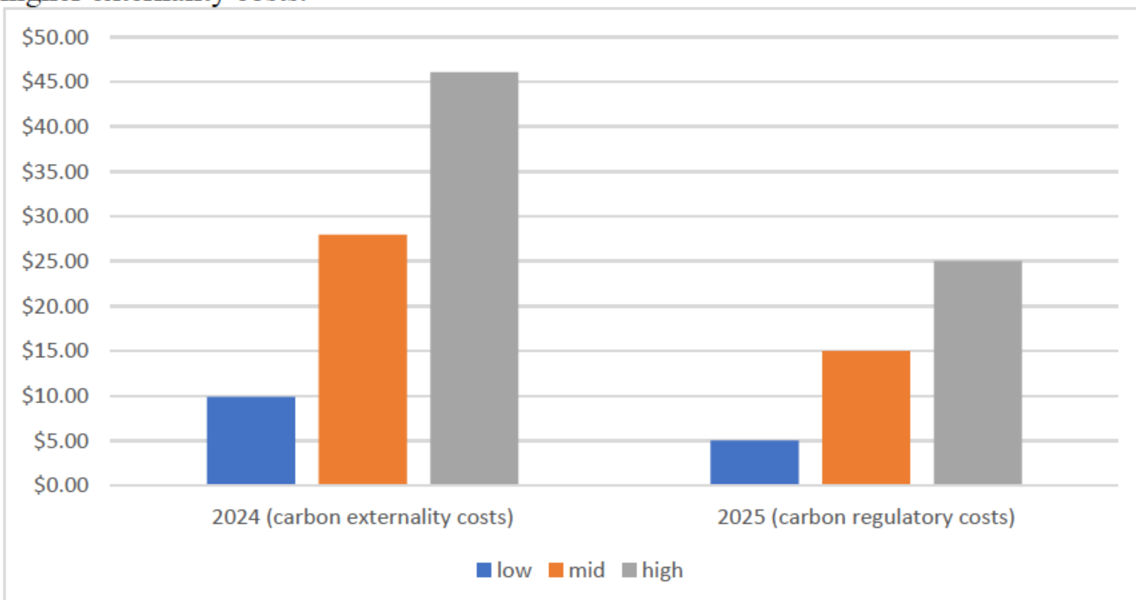
[222] Coral Davenport and Lisa Friedman, *"Build Back Better" Hit a Wall, but Climate Action Could Move Forward,* New York Times (Jan. 20, 2022), *available at* https://www.nytimes.com/2022/01/20/climate/build-back-better-climate-change.html
[223] Coral Davenport, *Biden Crafts a Climate Plan B: Tax Credits, Regulation and State Action,* New York Times (Oct. 22, 2021), *available at* https://www.nytimes.com/2021/10/22/climate/biden-climate-plan.html.
[224] Minn. Pub. Utils. Comm'n, *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3,* Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643 (Jan. 3, 2018).

with carbon emissions drops nearly in half in 2025 (see Figure 3), suggesting those emissions are suddenly much less of a problem when in fact both the climate crisis and carbon regulatory risk will surely be intensifying.

Figure 3. Carbon externality costs versus carbon regulatory costs. The Commission's estimated carbon regulatory costs, assumed to begin in 2025, substitute for considerably higher externality costs.[225]



The true costs of carbon emissions – both to the utility and society – also get obscured in another way, as illustrated by the strange results of Minnesota Power's EnCompass modeling. Minnesota Power's IRP compares its Preferred Plan with Swim Lanes where one or both Boswell units are retired earlier. It repeats that comparison under each of the five different environmental futures the Commission requires, assuming higher and lower regulatory and environmental costs in different combinations.[226] The Preferred Plan comes out cheaper than earlier retirement of the Boswell units under most of the 38 sensitivities examined when assuming mid-level regulatory and environmental costs (the results Minnesota Power featured in the IRP[227]) and when assuming

[225] *Id.* at 9-10.
[226] *Id.* at 9.
[227] MP IRP at 57.

high carbon costs and high environmental costs (the results submitted with the IRP as Appendix K[228]).

Counterintuitively, though, under the other three environmental futures, which assume no or low carbon costs, Minnesota Power's modeling finds that it is actually cheaper to retire one or both Boswell units earlier (results submitted after the IRP as Supplemental Appendix K[229]). Indeed, assuming a future with no carbon regulatory costs, early retirement of both Boswell units has a lower cost than the Preferred Plan under virtually all 38 sensitivities.[230] In other words, instead of high carbon regulatory costs driving the earlier retirement of Boswell 3 and 4, Minnesota Power's modeling suggests that high carbon regulatory costs are a reason to delay their retirement. Minnesota Power dismissed the three environmental futures that favored earlier retirement of Boswell as reflecting an "environmental future design shortcoming."[231] However the same design shortcoming applies to the two scenarios that favor the Preferred Plan.

Together these upside-down scenarios illustrate that the Commission cannot assume that Minnesota Power's IRP reflects actual carbon regulatory risk merely because its modeling incorporates the Commission's estimated carbon costs. They also illustrate another reason why the Commission should update its regulatory cost estimates and its rules for how they are applied to ensure they yield analyses that are useful to long-term resource planning.

[228] MP IRP, Appendix K at 17.
[229] MP IRP, Supplemental Appendix K, at 26-28.
[230] *Id.*
[231] *Id.* at 24.

VII. A MINNESOTA POWER RESOURCE PORTFOLIO THAT INCLUDES MORE DISTRIBUTED SOLAR PRESENTS AN OPPORTUNITY TO BE CLEANER AND MORE EQUITABLE, CREATE JOBS FOR MINNESOTANS, AND PROVIDE COST-EFFECTIVE SOLAR TO THE SYSTEM

Multiple recent studies have shown that investing in distributed solar generation can lower system costs, deliver cleaner energy, and create more local jobs than portfolios that only focus on utility-scale resources.

For example, a recent study by Vibrant Clean Energy, LLC, "Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid: Technical Report," illustrates how traditional capacity expansion planning models fail to capture the reliability benefits of distributed generation.[232] In the study, VCE used the *Weather-Informed energy Systems: for design, operations and markets planning* (WIS:dom®- P) optimization software tool, which is a combined capacity expansion and production cost model.[233] Traditional modeling tools do not integrate and optimize the benefits of locally-sited solar and storage. One of the key differences between WIS:dom and other modeling tools is its ability to optimize the addition of distributed solar and storage as resources, instead of using a pre-determined buildout rate as a load modifier (as Minnesota Power has done in its IRP modeling).[234]

In its study, VCE evaluated whether distributed energy resources (distributed solar PV, energy efficiency, demand-side management, demand response, and distributed storage, or "DER") can lower costs across the US electricity system compared to alternatives, while maintaining resource adequacy, reliability and resilience. The study found that customers could

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[232] *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid,* Vibrant Clean Energy, LLC, on behalf of Local Solar for All, Vote Solar, and Coalition for Community Solar Access, (Dec. 1, 2020) *available at* https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf.
[233] *Id.* at 1.
[234] *Id.* at 1-3.

save a cumulative $473 billion by employing a clean energy standard that reduces emission by 95% from 1990 levels by 2050, while creating 2 million more jobs nationally.[235] (On a population basis, this translates into 33,800 additional jobs in Minnesota.) This cleanest, lowest-cost grid requires 223 GW more local solar nationwide.[236] The report found that traditional utility planning based on construction of utility scale generation fails to take into account the many benefits of a more distributed resource system, leading to an over-reliance on overbuilding peaking plants. Adding an optimal amount of distributed resources (by considering these benefits) allows the transmission system to be better utilized, and reduces the amount of peaking resources required. VCE's optimization shows that dramatically more distributed generation is beneficial than traditional models and utility planning account for.

Minnesota Power's proposed plan understates the role that community solar and distributed solar generation can and should play in its future. The Company modeled DG as a modifier to its load forecast. In doing so, Minnesota Power overlooks the role it can play in incentivizing its customers to leverage their own capital to the benefit of the system. As Sierra Club and the Distributed Solar Parties ("DSPs") showed in the Xcel IRP, the utility can encourage incremental distributed generation additions at a lower cost than utility-scale solar.[237] For IRP modeling purposes, the total resource cost is the cost to the utility of offering an incentive, such as an upfront rebate. In the Xcel IRP, Sierra Club and the DSPs modeled bundles of DG at each incentive level,

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[235] *Id.*
[236] *Id.*
[237] Minn. Pub. Utils. Comm'n, Sierra Club's Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 38-40 (Feb. 11, 2021); Minn. Pub. Utils. Comm'n, Joint Comments of Vote Solar, Institute for Local Self Reliance, the Environmental Law and Policy Center, and Cooperative Energy Futures, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368 (Feb. 11, 2021).

similar to how Minnesota utilities model energy efficiency, and found that adding over 1,800 MW of distribution-connected solar would significantly decrease the overall plan costs.

In response to advocacy on the part of Minnesota Interfaith Power & Light and other local partners, Minnesota Power now offers a low-income solar grant program. This program should be expanded to provide greater opportunities for low-income MP customers to access the benefits of distributed solar. Moreover, as a significant percentage of low-income residents in Duluth are renters, not homeowners, Minnesota Power has an opportunity to expand low-income community solar projects to further increase equitable access to distributed solar.

A plan that includes both robust investment in utility scale renewables as well as strong deployment of distributed and low-income-focused community solar can deliver more in terms of job creation and community-located investment and is a key tool to a more equitable energy delivery system. Because of the benefits that distributed solar generation can offer to Minnesota Power's customers, Minnesota Power should work with stakeholders to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid as a resource, take steps to better align distribution and resource planning, and consider local community generation goals for distributed generation in its next IRP.

VIII. RETIRING BOSWELL AND HIBBARD EARLY AND NOT BUILDING NTEC WOULD GREATLY REDUCE HUMAN HEALTH IMPACTS, ESPECIALLY IMPACTS ON OVERBURDENED COMMUNITIES

A. The Commission Should Take Into Account Health And Equity When Examining Minnesota Power's Resource Plan.

The Commission evaluates resource plans, in part, for their ability to "minimize adverse socioeconomic effects and adverse effects upon the environment,"[238] and, ultimately, the

[238] Minn. R. 7843.0500, subp. 3(C).

Commission is tasked with choosing a resource plan in the public interest.[239] As the State of Minnesota moves to decarbonize our energy sector, utility resource planning has major implications for public heath, environmental justice, economic development, worker and community energy transition impacts, and socio-economic disparities. In this docket, the Commission is considering the future of Minnesota Power's existing fleet and the changes that need to be made to meet future demand. These decisions should not be made without carefully considering the public health impacts of Minnesota Power's existing resources. And, examining public health and equity impacts is especially consequential in dockets like this one where the alternate generation portfolios presented by CEOs show only very small differences in direct cost.[240]

A broad range of stakeholders, as well as the Commission, have recognized the connections between resource planning and equity. In the recent Xcel IRP, many intervenors raised health and equity concerns. In that IRP, Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, Union of Concerned Scientists,[241] Sierra Club,[242] Energy Efficiency for All Partners,[243] the City of Minneapolis,[244] St. Paul 350,[245] among others, all implored the Commission to center equity when making a resource planning decision. The Commission's

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[239] Minn. Stat. § 216B.2422, subd. 2(a).
[240] *See* Part III.
[241] Minn. Pub. Utils. Comm'n, CEOs' Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 43 (Feb. 11, 2021).
[242] Minn. Pub. Utils. Comm'n, Sierra Club's Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 97 (Feb. 11, 2021).
[243] Minn. Pub. Utils. Comm'n, Comments of Fresh Energy, Community Stabilization Project, Green & Healthy Homes Initiative, Inquilinxs Unidxs Por Justicia, Minnesota Housing Partnership, National Housing Trust, and Natural Resources Defense Council ("EEFA Partners"), *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 2-5 (Feb. 11, 2021).
[244] Minn. Pub. Utils. Comm'n, Comments of the City of Minneapolis, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 5 (Feb. 11, 2021).
[245] Minn. Pub. Utils. Comm'n, SP350 Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 8 (Feb. 11, 2021).

decision in that docket requires Xcel to conduct community outreach and go through a stakeholder process to achieve various equity goals. Those equity measures include, "equitable delivery of electricity services and programs" and designing incentives "that ensure that communities of low income, Black, indigenous, and People of Color that have disproportionately borne costs of unjust and inequitable energy decisions have equitable access to programs promoting distributed generation."[246]

CEOs ask the Commission to examine disparate health impacts in this docket because historical decisions around power plant siting have systematically exposed BIPOC communities across the country to higher levels of harmful air pollution,[247] among other hazards. Minnesota is no exception; for example, the Minnesota Pollution Control Agency has recognized that "discriminatory housing policies, the placement of freeways in Black neighborhoods, and zoning and permitting decisions" resulted in BIPOC communities experiencing higher pollution.[248] One salient example for this docket is the Boswell Energy Center's close proximity to the Leech Lake Band of Ojibwe land. Boswell was built abutting the border in the 1950s during the United States' "Voluntary Relocation Program," a program designed to "assimilate American Indians" by forcing them off of reservation lands and into the cities.[249] Our State has recognized that "[d]isparities in Minnesota, including those based on race, geography, and economic status, keep our entire state

[246] Minn. Pub. Utils. Comm'n, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, para. 25 (Apr. 15, 2022).

[247] Haley M. Lane, et al., *Historical Redlining Is Associated with Present-Day Air Pollution Disparities in U.S. Cities,* Environmental Science and Technology Letters (2022), *available at* https://pubs.acs.org/doi/pdf/10.1021/acs.estlett.1c01012.

[248] *The air we breathe: The state of Minnesota's air quality in 2021*, Minn. Poll. Control Agency, 7 (Jan. 1, 2021) *available at* https://www.pca.state.mn.us/sites/default/files/lraq-2sy21.pdf.

[249] *American Indian Urban Relocation Program,* U.S. Nat'l Archives, *available at* https://www.archives.gov/education/lessons/indian-relocation.html.

from reaching its full potential."[250] As one step towards addressing these disparities, CEOs ask the Commission to consider public health and equity in this IRP.

B. Incorporating Health And Equity Metrics Report Methodology

CEOs commissioned a report from Physicians, Scientists, and Engineers for Healthy Energy ("PSE") to include as part of CEOs' filing. "PSE is a multidisciplinary, nonprofit research institute dedicated to supplying evidence-based scientific and technical information on the public health, environmental, and climate dimensions of energy production and use."[251] The purpose of this report is to evaluate the public health and energy burden impacts of Minnesota Power's Preferred Plan.

CEOs have included this report from PSE to provide one example of how equity issues can be included in a direct and quantitative manner in resource planning proceedings. PSE focuses the report on three primary areas: excess mortality caused by coal and biomass plant emissions, lifecycle greenhouse gas impacts of new gas plants like NTEC, and strategies to reduce energy burden and improve equity of clean energy access. CEOs recognize that this analysis does not cover every equity issue implicated by Minnesota Power's resource plan; rather, PSE focuses on three issues emphasized by CEOs.

First, the PSE report evaluates public health impacts of coal use and the potential benefits from retiring these facilities early. Although coal and biomass plants produce a variety of emissions, the PSE report focuses on $PM_{2.5}$ for two reasons: $PM_{2.5}$ typically represents the majority of adverse impacts from coal plant emissions, and there are established and widely accepted ways

[250] Exec. Order 19-01, Establishing the One Minnesota Council on Diversity, Inclusion, and Equity, State of Minnesota, Exec. Dep't. (Jan. 9, 2019) *available at* https://mn.gov/governor/assets/2019_01_09_EO-19-01_%28FINAL%29_tcm1055-364605.pdf.
[251] PSE Report, Executive Summary.

to model $PM_{2.5}$. However, this health impact modeling likely underestimates health impacts caused by pollutants that are not modeled.[252]

To establish a baseline for coal and biomass emissions, PSE used emissions data from historic operations. Then, PSE modeled the anticipated health impacts from Minnesota Power's planned usage of the coal and biomass plants for 2021-2035. These health impacts include nonfatal heart attacks, respiratory-related hospital admissions, upper respiratory symptoms, and mortality.[253] The PSE Report estimated mortality resulting from operation of the plant and how those deaths are concentrated geographically around the plants.[254] In addition to health impacts from emissions, the PSE report also explores toxicity and environmental impacts from coal ash disposal, as well as coal plant water usage.[255]

Importantly, PSE examined *which* communities are experiencing these health impacts. The report maps the geographic distribution of each power plant's emissions and presents the overall demographic and racial disparities of the health impacts resulting from these coal and biomass resources.[256] PSE also takes a deeper look at the communities in closest proximity to each plant, which are generally the most-impacted populations. They use a Demographic Index composed of six key factors to evaluate the socio-economic characteristics and relative vulnerability to air pollution of plant host communities compared to the general population.[257]

Second, the PSE report highlights the underestimated methane emissions for gas plants like NTEC. Due to significant leakage throughout the entire gas system, the climate impacts of gas plants like NTEC are much higher than simply the CO_2e [or greenhouse gas] emissions produced

[252] *Id.* at Section 2.2.
[253] *Id.* at Section 3.2.2.
[254] *Id.* at Section 3.2.4.
[255] *Id.* at Sections 3.2.5 and 3.2.6.
[256] *Id.* at Sections 2.1 and 2.2.
[257] *Id.* at Section 2.1.

directly at the power plant. The report uses recent scientific literature to estimate the actual global warming contributions of NTEC considering upstream emissions.[258]

Third, the PSE report evaluated the energy access and equity issues facing Minnesota Power's customers. Because granular data is not available for residential energy consumption, PSE started by estimating household energy consumption in each census tract using a linear regression model that approximates energy consumption by fuel type and how the energy is being used. Then, PSE used census tract-level energy consumption to estimate how much households are spending on energy. Finally, PSE compared the energy expenditures in each census tract with the census tract's median household income in order to arrive at the "cost burden."[259]

C. Report Findings.

1. Minnesota Power's coal and biomass facilities have significant public health consequences.

PSE's public health analysis found that the coal and biomass power plants currently in Minnesota Power's portfolio have significant local and regional health impacts. Collectively, emissions from Boswell, Hibbard, and Minnesota Power's purchases from Milton R. Young were responsible for 16 excess deaths and $177 million in public health costs in 2021.[260] This cost figure represents an estimate of the monetary value of additional hospital visits, healthcare requirements, missed work and school, etc., that result from the health impacts of fine participate pollution ($PM_{2.5}$), which include exacerbated asthma, heart attacks, irregular heartbeat, premature birth, and premature death.

PSE's modeling indicates that, if these three plants run as described in Minnesota Power's Preferred Plan between now and 2035, they will cause an additional 100 premature deaths (on

[258] *Id.* at Section 3.4.
[259] *Id.* at Section 2.4.
[260] *Id.* at Section 3.2.2.

average, 6-7 deaths per year) and over $1 billion in public health costs.[261] It is worth noting again that these mortality and public health cost estimates are conservative. They are based exclusively on the impacts of $PM_{2.5}$ and do not include additional impacts from VOCs, NO_X, SO_2, or ozone. Additionally, these figures only include the impacts from Minnesota Power's purchases from Young which are set to end after 2025, while the plant is likely to continue operating well past that date.

PSE evaluated the public health benefits of earlier retirement dates for the two Boswell units. It found that retiring Unit 3 five years early (at the end of 2024 instead of 2029) would save 3-4 lives and $39 million in health costs, while retiring Unit 4 after 2029 instead of running it through 2035 would save 14-15 lives and $164 million in health costs.[262] PSE also found that earlier retirements would have significant benefits for reducing coal ash waste stored on the Boswell site. Coal ash at Boswell contains several highly toxic substances that can cause adverse human and wildlife health impacts and poses a "significant hazard" to nearby communities if Boswell's coal ash ponds were to fail.[263]

PSE also evaluated the public health impacts of the Milton R. Young coal-fired power plant and found that Young has large public health costs for Minnesotans. In fact, PSE found that "its cumulative health impacts in Minnesota are actually slightly higher than in North Dakota itself."[264] PSE's modeling shows that the electricity MP has committed to purchase from Young is expected to cause 3-4 excess deaths per year and $110 million in health costs through 2025, when the contract expires. Unless the contract expiration coincides with a reduction to plant output, however, these adverse health impacts will continue.

[261] *Id.* at Section 3.2.3.
[262] *Id.* at Section 3.2.3.
[263] *Id.* at Section 3.2.5.
[264] *Id.* at Section 3.2.4.

The public health impacts of the Hibbard biomass and coal plant are perhaps the most stark and actionable finding in this analysis. While the plant's future operations are hard to predict due to recent changes at the associated paper mill, the historical emissions and impacts on the surrounding community are enormous, especially considering the plant's size. PSE's evaluation of 2021 data shows that Hibbard had greater adverse health impacts than any of the other plants: 6.7 excess deaths, versus 6.2 from Boswell, and $70 million in estimated public costs, versus $67.7 million from Boswell.[265] Hibbard has a nameplate capacity of 47MW, roughly 5% the size of Boswell – and yet its adverse health impacts exceed those of a coal plant 20 times its size. These factors indicate that the public interest will be best served by shutting Hibbard down as soon as possible.

Table 6. Health Impacts of Minnesota Power's Coal and Biomass Power Plants

	Hibbard	**Boswell**	**Young**
Plant Size	47MW	932MW	439MW
Excess Deaths - 2021	6.4 deaths	6.2 deaths	3.5 deaths
Public Health Costs - 2021	$70 million	$67.7 million	$39 million
Excess Deaths – projected through 2035	Unknown	47.5 deaths	10 deaths
Public Health Costs - projected through 2035	Unknown	$534 million	$110 million

2. The health costs of these plants fall most heavily on lower-income communities, communities of color, and Native populations.

Communities located nearest to and downwind of these plants face the highest per-capita health consequences. PSE's evaluation of the socio-economic and geographic distribution of health impacts from the plants found that health costs are disproportionately impacting

[265] *Id.* at Section 3.3.

communities with high socio-economic burdens that make residents more vulnerable to the respiratory and cardiac impacts from $PM_{2.5}$.[266]

PSE's modeling of the geographic distribution of Boswell's health consequences shows that the plant impacts a huge swath of the country, spanning from northeastern Minnesota to the mid-Atlantic. However, per capita impacts are highest in Minnesota communities surrounding and east of the plant.[267] The community living closest to Boswell is significantly lower-income and more vulnerable to pollution impacts than the Minnesota population at large: PSE found that the population within one mile of Boswell ranks at the 81st percentile for low-income populations and ranks at the 71st percentile on PSE's Demographic Index, which combines several demographic factors to provide a composite risk score.[268] The racial distribution of these health costs is quite uneven: Native populations face per-capita health costs from Boswell that are nearly three times higher than the overall population.[269]

Due to the Young plant's remote location, PSE did not evaluate the *immediate* community's demographics, but its overall per-capita health impacts are quite unevenly distributed: Native populations face public health costs 2.5 times greater than the overall population impacted by emissions from the Young plant.[270]

Importantly, Hibbard is located in an urban area with a significant population nearby – 30,000 people live within a three-mile radius – and near lower-income communities and populations more vulnerable to health impacts of air pollution. PSE found that the population within one mile of the plant is lower income than 89% of census tracts in Minnesota, and more

[266] *Id.* at Section 4.
[267] *Id.* at Section 3.2.4.
[268] *Id.* at Section 3.1.
[269] *Id.* at Section 3.2.4.
[270] *Id.*

vulnerable (per PSE's Demographic Index) than 78% of the state. Additionally, Hibbard's pollution disproportionately impacts Native populations, who face health costs from Hibbard three times higher than the overall impacted population.[271]

In fact, PSE found that "for every plant analyzed, the health impacts per capita were highest for Native populations, and larger by a factor of two to three as compared to the population at large."[272] This is likely due to the location of many of these plants close to and upwind of Tribe lands and populations. Hibbard is located just east of the Fond du Lac reservation and upwind of Grant Portage, while Young is located upwind of all tribal lands in Minnesota. The Boswell facility is located directly adjacent to the Leech Lake Band of Ojibwe reservation boundary and is upwind from the Fond du Lac, Milles Lacs, Bois Forte, and Grand Portage Reservations.

The disproportionate impacts that pollution from Hibbard and Boswell have on lower-income and Tribal communities in Minnesota is a critical factor to consider in decisions about these facilities' futures. CEOs have discussed the results of this report with representatives of several of the Tribes noted above. We hope to have ongoing conversations about how to best utilize this information and how to improve public health and equity analyses for future regulatory proceedings. Input from Tribes, native residents, and others directly impacted by the health costs of these plants will be quite valuable to this proceeding.

CEOs urge the Commission to consider the magnitude of these public health impacts when making decisions about future plant operations and Minnesota Power's generation portfolio. In the case of Hibbard, the public interest is clear – not only is this plant exacting dramatic health costs on nearby communities, but CEOs' modeling shows that continued operation of Hibbard is unnecessary, and an immediate 2023 retirement is cost effective.

[271] *Id.* at Section 3.1.
[272] *Id.* at Section 3.2.4.

3. Accounting for upstream methane emissions and facility N_2O emissions doubles NTEC's expected climate impacts.

PSE's evaluation of NTEC focused on providing a comprehensive assessment of the plant's likely climate impacts, specifically by considering the greenhouse gas impacts of upstream methane emissions and the facility's emissions of nitrous oxide ("N_2O"), another extremely potent greenhouse gas. Scientists and policy makers, including the Minnesota Legislature[273] and this Commission,[274] are recognizing the importance of considering upstream methane emissions when evaluating the climate impacts of fossil gas infrastructure. A recent meta-analysis of methane leakage in the U.S. found that methane leaks at a rate of 2.9 % of fossil gas delivered to end-users, and as a result the radiative forcing (global warming impact) of fossil gas over a 20-year horizon is 92% higher than its direct CO_2 emissions from combustion.[275]

The scale of these typically unaccounted-for greenhouse gas impacts is dramatic. In fact, the climate impacts of NTEC more than double when considering upstream methane emissions and facility N_2O emissions. While the most recent air permit for NTEC suggests that the facility will produce 2.24 million tons of CO_2 per year,[276] PSE's analysis found that the actual greenhouse gas impact of the plant will be 4.8 million tons CO_2e annually (when considering a 20-year horizon for methane).[277] MP's share of these emissions, assuming 20% ownership, would be 960,000 tons CO_2e, rather than 448,000 tons CO_2 per year.

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[273] *See* Minn. Stat. § 216B.2427, subd. 2(a)(3); Minn. Stat. § 216B.241, subd. 2(k).
[274] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Order Accepting Report and Setting Additional Requirements, Docket No. E-002/CI-17-401, Order 6-7 (Feb. 9, 2022).
[275] Ramón A. Alvarez, et al., *Assessment of Methane Emissions from the US Oil and Gas Supply Chain. Supplementary Material*, Science, 186-188 (June 21, 2018) *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6223263/.
[276] Wisc. Dep't. Nat. Resources, Nemadji Trail Energy Center, FID No. 816127840 / Permits 18-MMC-168 and 21-MMC-11 Air Pollution Control Construction Permit Application, Section 1.2 (Dec. 10, 2021).
[277] PSE Report at Section 3.4.

PSE did not model potential PM or NO_x emissions for this yet-to-be-developed plant, but notes that Syl Laskin, MP's fossil gas peaker plant, has a higher rate of NO_x emissions per MWh than Boswell.[278] When meteorological conditions are poor, such as during peak summer days, fossil gas plants can significantly contribute to poor air quality and acute health impacts as "high NO_x emissions may contribute to increased ozone or secondary $PM_{2.5}$ formation."[279]

The Commission should also consider the demographics of the community nearest NTEC, which will be most impacted by the respiratory effects of ozone, secondary $PM_{2.5}$ and related emissions if NTEC is built. The plant is proposed to be located in a population center with 15,000 people living within a three-mile radius of the NTEC site. This population ranks in the 74th percentile for low-income population in Wisconsin and 66th percentile on PSE's demographic index.[280] The proposed NTEC site is also quite close to the Fond du Lac reservation. Given these demographic factors, emissions from NTEC will have public health consequences for a nearby community that is significantly lower-income and more vulnerable to the health consequences of pollution than the state population at large.

4. Minnesota Power should invest more in low-income residential efficiency projects and community solar projects that prioritize access for under-resourced customers to reduce electricity costs and disparities in energy burden.

Assessments of population characteristics in utility service areas can reveal important insights with respect to energy access and equity. The information can in turn lead to potential changes in resource portfolios or be used in other proceedings dealing with how programs such as energy efficiency or distributed solar are structured and applied. As a first step, PSE provides a methodology for calculating average household energy cost burdens for each census tract in utility

[278] *Id.*
[279] *Id.*
[280] *Id.* at Section 3.1.

service areas.[281] Energy cost burden—the percentage of household income used to pay energy bills—is typically considered high if over 6%.[282] PSE found notably high energy burdens in rural areas of Minnesota Power's service territory and particularly in parts of Duluth.[283]

PSE next estimated that the low-income population in Minnesota Power's service area is about 30% of the total population and developed a spatial distribution of low-income households by census tract.[284] PSE noted the especially high concentration of low-income households in the downtown Duluth area. Examining Minnesota Power's energy efficiency investments and projected residential efficiency savings, PSE found that the company's efficiency investments in low-income communities have historically averaged 20% of total efficiency investments, producing projected residential savings in low-income households of only 13% of total savings in the near-term (2021–2023) and only 11% in the longer-term (2024-2029).[285]

These proportions are inequitable given that the fraction of low-income population in Minnesota Power's service area is closer to 30%. Accordingly, PSE recommends that Minnesota Power's investments in low-income residential efficiency should be tripled as a fraction of the total levels of efficiency investment currently planned, while also ensuring that at least one-third of projected energy savings are attained in low-income communities.[286]

Fresh Energy made a similar recommendation to Minnesota Power in its August 12, 2020, joint comments on Minnesota Power's proposed 2021-2023 Conservation Improvement Program

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[281] *Id.* at Section 3.5.
[282] *Id.* at Section 3.5.1.
[283] *Id.* at Figure 12.
[284] *Id.* at Section 3.5.2.
[285] *Id.*
[286] *Id.*

Triennial Plan.[287] While inequities remain in Minnesota Power's approved Triennial Plan,[288] the utility's spending on low-income energy conservation programs (as a percentage of overall energy conservation spending) was the highest among utilities required to submit Triennial Plans at the time. Minnesota Power was the sole utility whose 2021-2023 Triennial Plan met and exceeded the increased low-income minimum spending requirements outlined in the Energy Conservation and Optimization Act of 2021 ("2021 ECO Act") before the Act's passage.[289] This is commendable. The 2021 ECO Act requires that public utilities like Minnesota Power increase minimum spending levels on low-income energy conservation measures from 0.1% to 0.4% of gross operating revenue from residential customers in 2022, and then again to 0.6% in 2024.[290] We will continue to advocate through the Conservation Improvement Program proceedings for Minnesota Power (and all other utilities) to ensure investments in and energy savings from low-income energy conservation programs go beyond meeting statutory minimum requirements and are instead proportional to meeting the needs of under-resourced customers in Minnesota Power's service territory.

With respect to rooftop solar and access to the benefits of distributed solar, PSE found another inequitable situation: less than 5% of rooftop solar adopters in Minnesota are in the lowest-income bracket, while more than 40% are in the highest-income category.[291] While Minnesota

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[287] Minn. Dep't. of Commerce, Joint Comments of Fresh Energy, National Housing Trust (NHT), and Natural Resources Defense Council (NRDC*), In the Matter of Minnesota Power's 2021-2023 Electric Conservation Improvement Program Triennial Plan*, Docket No. E015/CIP-20-476 (Aug. 12, 2020).

[288] As Fresh Energy reiterated in joint comments to the Department of Commerce's proposed decision to approve Minnesota Power's Triennial Plan, submitted with NHT, NRDC, Minnesota Housing Partnership, and the cities of Minneapolis and Saint Paul. *See* Minn. Dep't. of Commerce, Joint Comments, *Staff's Proposed Decisions Regarding 2021-2023 CIP Triennial Plans*, Docket No. E015/CIP-20-476 (Oct. 13, 2020).

[289] The Energy Conservation and Optimization Act of 2021, H.F. 164, 92nd Leg. (Minn. 2021).

[290] Minn. Stat. § 216B.241, subd. 2b(b).

[291] PSE Report at Section 3.5.3.

Power's SolarSense and low-income solar grant programs aim to expand solar adoption, funding is capped and therefore these programs have limited reach. The 2020 extension of SolarSense and expansion of funding for the low-income grant program are positive steps.[292] PSE recommends MP make additional investments in community solar projects that prioritize access for under-resourced customers to reduce electricity costs and disparities in energy burden. CEOs agree with PSE's recommendations.

PSE's assessment of energy access and equity issues in Minnesota Power's plan demonstrates both how such an analysis can be conducted and how to use these insights to inform planning priorities and program design. The analysis PSE conducted, for example, demonstrates the importance of calibrating investment levels to achieve equitable outcomes in key customer cost-saving resources such as energy efficiency and distributed solar.

D. Summary of Report Findings and Implications for this Proceeding.

The PSE report has several conclusions that are important for the Commission's consideration in this proceeding and future IRPs.

1. Minnesotans could see significant public health benefits from earlier retirement dates for the coal and biomass plants in MP's portfolio. Boswell has significant negative health impacts for the region, and Hibbard, though a small source of power, has disproportionately large health impacts. The state could save hundreds of millions of dollars in health costs by closing these facilities earlier than MP plans. Importantly, these health costs fall disproportionately on lower-income communities and native populations in Minnesota – communities that face disproportionate burdens on a range of health and socioeconomic measures as a result of historic and current inequities.

2. NTEC's true climate impacts are more than double its direct CO_2 emissions. It is crucial that Minnesota take upstream methane and methane leakage into account when evaluating the social costs of fossil gas infrastructure.

3. To address disparities in energy burden, and even to prevent exacerbation of current disparities, Minnesota Power must commit to its low-income energy conservation

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[292] Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's Petition for Approval of Its New SolarSense Customer Solar Program*, Order Approving Program Extension and Changes, In Part, With Modifications, Docket No. E-015/M-20-607 (Dec. 17, 2020).

programs achieving 33% of overall residential energy savings. Minnesota Power should also increase investments in community solar projects and distributed generation programs that reduce electricity costs and extend clean energy access to a significantly larger number of low-income customers.

4. Resource planning can and should include a robust analysis of the equity implications of potential resource pathways. This report provides one example of how Minnesota utilities' resource planning processes can consider in an empirical way the public health impacts of electricity generation choices, and the geographic and demographic distribution of those impacts.

IX. RECOMMENDATIONS

We respectfully request that the Commission:

A. Modify Minnesota Power's IRP by:
    1. ordering Minnesota Power to withdraw from the NTEC project and revoking the Commission's approval of the related affiliate interest agreements;
    2. ordering retirement of the Hibbard plant in 2023; and
    3. finding the need for approximately 600 MW of solar by 2026.

B. Order the retirement of Boswell 3 by the end of 2029.

C. Order that Minnesota Power:
    1. commence planning the transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030; and
    2. submit annual reports to the Commission beginning one year from the date of this order and continuing until the filing of the next IRP. Such reports must:
        i. describe work done to date and work yet to be completed, providing a schedule of expected milestones, and estimating the earliest date for completion of the transmission system reliability mitigations; and
        ii. specifically evaluate converting Boswell 3 to a synchronous condenser upon retirement.

D. Order that Minnesota Power work with stakeholders to include an analysis in the next IRP that identifies the near-term steps needed to ensure Minnesota Power meets its customers' needs in a fashion compatible with 1.5°C pathways.

E. Commence a proceeding to update the estimates of the likely range of costs of future carbon dioxide regulation on electricity generation pursuant to Minn. Stat. § 216H.06 and the rules for their application.

F. Order that Minnesota Power:[293]
   1. work with stakeholders to develop a modeling construct that enables Minnesota Power, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:
      i. using a "bundled" approach as is used to model energy efficiency and demand response;
      ii. the costs borne by the utility and the costs borne by the customer;
      iii. cost effectiveness tests; and
      iv. other topics as identified by stakeholders.

   2. take steps to better align distribution and resource planning, including:
      i. set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
      ii. conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
      iii. proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
      iv. improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
      v. plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.

   3. account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation in its next IRP.

G. Order that Minnesota Power's next IRP include an analysis of the public health impacts, over the 15-year planning period, of its current generation fleet, its proposed plan, and other resource scenarios studied. The public health analysis should at minimum evaluate and quantify the health costs associated with fine particulate matter from coal and biomass power plants.

[293] Similar language was recently adopted in by the Commission: Minn. Pub. Utils. Comm'n, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company, d/b/a Xcel Energy,* Order Approving Plan with Modifications and Establishing Requirements for Future Filings, Docket No. 19-368 para. 15 (April 15, 2022).

H. Order Minnesota Power to, prior to the next IRP, conduct community outreach and establish a stakeholder group to:[294]
   1. provide input on the public health analysis for the next IRP, including the methodology, results, and implications for Minnesota Power's resource plan;
   2. inform the design of electricity services and programs that improve equitable electricity delivery, improve customer access to energy efficiency and load-shaping programs, and improve customer access to DG and renewable energy. These services and programs should particularly focus on reducing disparities in energy burden, ensuring equitable access to low-income residents, and ensuring equitable access to Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions;

I. Order Minnesota Power, in its next IRP docket, and in a separate docket to be established by the Executive Secretary, to file details describing stakeholder outreach and progress on the above requirements in H, (above) by January 1, 2024, and annually thereafter.

Dated: April 28, 2022

/s/Evan Mulholland
Evan Mulholland
Barbara Freese
Stephanie Fitzgerald
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[294] CEOs also relied on the Commission's language in its recent Xcel order for this recommendation. *Id.* para. 25 (Apr. 15, 2022).

ATTACHMENT CL-7

ALLETE, Inc. 2023 Form 10-K

ALLETE®

2023 Annual Report

March 2024

Dear ALLETE shareholders,

As the renewable energy transition accelerates, ALLETE is strategically positioned with both experience and momentum as we invest in and build the grid of the future. For the third year in a row, ALLETE in 2023 ranked first among U.S.-based investor-owned utilities for investment in wind and solar generation capacity as a percentage of market cap. Our team has deep experience in developing and operating renewable sites, and we have a track record of leading the way to a clean-energy future, putting sustainability into action for customers, communities, and shareholders.

We are building on that momentum in 2024. Minnesota Power issued Requests for Proposals (RFPs) for up to 300 megawatts of solar energy and up to 400 megawatts of wind energy as outlined in its 2022 Integrated Resource Plan approved by state regulators. Through these RFPs, Minnesota Power is doing more than seeking renewable energy—the company also is striving to maximize the economic and community benefits of clean energy development by including preferences for diverse bidders and domestically sourced materials, as well as requirements to use local prevailing wages and local labor for construction and permanent staffing and to develop apprenticeship programs to help train the energy workforce of tomorrow.

These solar and wind RFPs call for new renewable energy sites to be online by the end of 2027.

While adding renewable generation is vitally important, renewable megawatts will not help if we cannot move the energy to customers. That's why ALLETE and Minnesota Power are investing in transmission projects that will enhance the reliability and resilience of the regional grid across the Upper Midwest and beyond.

In October, the U.S. Department of Energy awarded a $50 million grant to Minnesota Power to modernize its high-voltage direct-current (HVDC) transmission system so it is ready to expand to meet future energy needs, while increasing the reliability and resilience of the regional grid. The company was selected in a competitive process from among hundreds of applicants nationwide. Minnesota Power also received $15 million in state funding for the project in May, with both government grants helping reduce costs for customers.

Earlier in 2023, Minnesota Power and Great River Energy filed an application for a Certificate of Need and Route Permit from the Minnesota Public Utilities Commission (MPUC) to build a high-voltage transmission line to bolster electric reliability in northern and central Minnesota. The Northland Reliability Project is an approximately 180-mile transmission line from northern Minnesota to central Minnesota. It will help maintain a reliable and resilient regional power grid as more renewable energy is brought online, as electrification continues to expand, and as extreme weather events become more frequent.

ALLETE also signed a development agreement in December with North Plains Connector LLC, a subsidiary of Grid United LLC, for the North Plains Connector project, a new, approximately 400-mile HVDC transmission line from central North Dakota to Colstrip, Montana.

The North Plains Connector will be the nation's first HVDC transmission connection between three regional U.S. electric energy markets—the Midcontinent Independent System Operator, the Western Interconnection, and the Southwest Power Pool. The project will be designed to transfer 3,000 megawatts across all three energy markets, easing congestion on the transmission system, increasing resiliency and reliability, and enabling fast delivery of energy resources across a vast area with diverse weather patterns.

Ensuring the financial health of our companies is part of a sustainable clean-energy transition. In late 2023, the MPUC approved an interim rate increase of 8.6% for Minnesota Power. The interim rate supports the company's ability to continue this important work, and we expect a decision on the company's full request of a 12% increase late this year. Superior Water, Light and Power also expects to file a rate request with Wisconsin regulators in coming months.

ALLETE's companies outside the regulated utility space also continue to make significant strides. New Energy Equity ended its first full calendar year as part of the ALLETE family of businesses by exceeding original financial expectations for 2023, and we are excited about its future.

ALLETE Clean Energy recently had a favorable arbitration outcome related to one of its wind facilities. Its team also continued their work to increase efficiencies and unit availability, while they implemented operations and maintenance reductions and took many other initiatives to endure historically low wind conditions over the past year.

ALLETE's achievements are the result of the innovation, talent, resilience, and hard work of a remarkable team. We have incredibly capable, skilled, and experienced people throughout ALLETE working toward the same goals, and we are excited about the future.

While ALLETE is making significant investments in clean energy and transmission that, in turn, build sustainable long-term earnings growth, we are building more than turbines, solar arrays, and power lines. ALLETE is committed to advancing the clean-energy future in deeply sustainable ways for the communities in which we live, work, and operate by providing opportunities for others as we move forward. With integrity as our guide, we're striving to advance this vital energy transition in the right way for the climate and for our customers and communities. More details about this important work are included in our recently updated corporate sustainability report that can be found at allete.com.

We're proud that ALLETE increased its dividends again in early 2024, after 2023 earnings were in line with our expectations. We have an exciting future as together we build reliable, renewable energy sources and enhanced energy infrastructure while making substantial investments in our communities.

As always, thank you for your interest and investment in ALLETE.

Bethany M. Owen
ALLETE Chair, President and CEO

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the year ended **December 31, 2023**

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ______________ to ______________

Commission File Number **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093

(Address of principal executive offices, including zip code)

(218) 279-5000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, without par value	**ALE**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of voting stock held by nonaffiliates on June 30, 2023, was $3,320,941,939.

As of February 1, 2024, there were 57,578,222 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2024 Annual Meeting of Shareholders are incorporated by reference in Part III.

Index

Index (Continued)

Definitions

The following abbreviations or acronyms are used in the text. References in this report to “we,” “us” and “our” are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	**Term**
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc. and its subsidiaries
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ALLETE South Wind	ALLETE South Wind, LLC
ALLETE Transmission Holdings	ALLETE Transmission Holdings, Inc.
ArcelorMittal	ArcelorMittal USA LLC
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison	Bison Wind Energy Center
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
C&I	Commercial and Industrial
Camp Ripley	Camp Ripley Solar Array
Cenovus Energy	Cenovus Energy Inc.
CIP	Conservation Improvement Program
Cliffs	Cleveland-Cliffs Inc.
Company	ALLETE, Inc. and its subsidiaries
COVID-19	2019 novel coronavirus
CSAPR	Cross-State Air Pollution Rule
CTO	Chief Technology Officer
DC	Direct Current
DOC	U.S. Department of Commerce
ECO	Energy Conservation and Optimization
EPA	United States Environmental Protection Agency
ELG	Effluent Limitation Guidelines
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
FIP	Federal Implementation Plan
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
Hibbing Taconite	Hibbing Taconite Co.
HLBV	Hypothetical Liquidation at Book Value
Husky Energy	Husky Energy Inc.

Definitions (Continued)

Abbreviation or Acronym	Term
HVDC	High-Voltage Direct-Current
IBEW	International Brotherhood of Electrical Workers
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
IRP	Integrated Resource Plan
Item ___	Item ___ of this Form 10-K
kV	Kilovolt(s)
kW / kWh	Kilowatt(s) / Kilowatt-hour(s)
Lampert Capital Markets	Lampert Capital Markets, Inc.
Laskin	Laskin Energy Center
LLC	Limited Liability Company
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
Manitoba Hydro	Manitoba Hydro-Electric Board
MBtu	Million British thermal units
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
Moody’s	Moody’s Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
New Energy	New Energy Equity LLC
Nippon Steel	Nippon Steel Corporation
NIST	National Institute of Standards and Technology
Nobles 2	Nobles 2 Power Partners, LLC
NOL	Net Operating Loss
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Northshore Mining	Northshore Mining Company, a wholly-owned subsidiary of Cliffs
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NTEC	Nemadji Trail Energy Center
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park District	Palm Coast Park Community Development District in Florida
PPA / PSA	Power Purchase Agreement / Power Sales Agreement
PPACA	Patient Protection and Affordable Care Act of 2010

Definitions (Continued)

Abbreviation or Acronym	Term
PSCW	Public Service Commission of Wisconsin
PV	Photovoltaic
RFP	Request for Proposals
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
S&P	S&P Global Ratings
SIP	State Implementation Plan
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cliffs
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SOC	System and Organizational Controls
Sofidel	The Sofidel Group
South Shore Energy	South Shore Energy, LLC
Square Butte	Square Butte Electric Cooperative, a North Dakota cooperative corporation
Standard & Poor's	S&P Global Ratings
ST Paper	ST Paper LLC
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Town Center District	Town Center at Palm Coast Community Development District in Florida
United Taconite	United Taconite LLC, a wholly-owned subsidiary of Cliffs
UPM Blandin	UPM, Blandin paper mill owned by UPM-Kymmene Corporation
U.S.	United States of America
USS Corporation	United States Steel Corporation
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entities
WTG	Wind Turbine Generator

Forward-Looking Statements

Statements in this report that are not statements of historical facts are considered “forward-looking” and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there can be no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (often, but not always, through the use of words or phrases such as “anticipates,” “believes,” “estimates,” “expects,” “intends,” “plans,” “projects,” “likely,” “will continue,” “could,” “may,” “potential,” “target,” “outlook” or words of similar meaning) are not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-K, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- global and domestic economic conditions affecting us or our customers;
- changes in and compliance with laws and regulations or changes in tax rates or policies;
- changes in rates of inflation or availability of key materials and suppliers;
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements;
- weather conditions, natural disasters and pandemic diseases;
- our ability to access capital markets, bank financing and other financing sources;
- changes in interest rates and the performance of the financial markets;
- project delays or changes in project costs;
- changes in operating expenses and capital expenditures and our ability to raise revenues from our customers;
- the impacts of commodity prices on ALLETE and our customers;
- our ability to attract and retain qualified, skilled and experienced personnel;
- effects of emerging technology;
- war, acts of terrorism and cybersecurity attacks;
- our ability to manage expansion and integrate acquisitions;
- population growth rates and demographic patterns;
- wholesale power market conditions;
- federal and state regulatory and legislative actions that impact regulated utility economics, including our allowed rates of return, capital structure, ability to secure financing, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities and utility infrastructure, recovery of purchased power, capital investments and other expenses, including present or prospective environmental matters;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- the impacts on our businesses of climate change and future regulation to restrict the emissions of GHG;
- effects of increased deployment of distributed low-carbon electricity generation resources;
- the impacts of laws and regulations related to renewable and distributed generation;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our current and potential industrial and municipal customers’ ability to execute announced expansion plans;
- real estate market conditions where our legacy Florida real estate investment is located may deteriorate; and
- the success of efforts to realize value from, invest in, and develop new opportunities.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Part 1, Item 1A under the heading “Risk Factors” of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by ALLETE in this Form 10-K and in other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect ALLETE’s business.

Part I

Item 1. Business

Overview.

ALLETE is a leader in the nation's clean-energy transformation. Our businesses and dedicated employees deliver sustainable energy solutions that mitigate climate change, build thriving communities, help customers reach their sustainability goals and drive value for shareholders. In 2020, ALLETE's largest business, Minnesota Power, reached a milestone of providing 50 percent renewable energy to its retail and municipal customers in Minnesota, and in 2023 delivered 50 percent renewable energy to those customers. The Company envisions delivering 100 percent carbon-free energy to customers by 2050—a vision grounded in a steadfast commitment to climate, customers and community through its *EnergyForward* strategy. ALLETE Clean Energy, our second-largest business, is positioned at the heart of society's clean-energy transformation and owns, operates and has developed for others more than 1,600 megawatts of wind energy generation across eight states—helping some of the largest companies in the country reduce their carbon footprint. Our newest business, New Energy, is a leading developer of community, commercial and industrial, and small utility-scale renewable energy projects that has completed more than 500 MW in its history.

Minnesota Power's latest IRP, approved by the MPUC in an order dated January 9, 2023, outlines its clean-energy transition plans through 2035. These plans include expanding its renewable energy supply to 70 percent by 2030, achieving coal-free operations at its facilities by 2035, and investing in a resilient and flexible transmission and distribution grid. Minnesota Power has also set a target to achieve an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels. As part of these plans, Minnesota Power anticipates adding up to 700 MW of new wind and solar energy resources, and ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Minnesota Power's plans recognize that advances in technology will play a significant role in completing its transition to carbon-free energy supply, reliably and affordably.

In recent years, Minnesota Power has transformed its company-owned energy supply from more than a 95 percent reliance on coal to become a leader in the nation's clean-energy transformation. Since 2013, the company has closed or converted seven of its nine coal-fired units and added nearly 900 megawatts of renewable energy sources. Additionally, Minnesota Power has been a leader in energy conservation, surpassing the state's conservation goals each year for the past decade.

On February 7, 2023, the Minnesota Governor signed into law legislation that updates the state's renewable energy standard and requires Minnesota electric utilities to source retail sales with 100 percent carbon-free energy by 2040. The Company is evaluating the law to identify challenges and opportunities it could present. Minnesota Power is also working with various stakeholders and participating in the regulatory process to implement this legislation. (See *Regulated Operations – Minnesota Legislation*.)

ALLETE is committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses, and sustains growth. ALLETE is predominately a regulated utility through Minnesota Power, SWL&P, and an investment in ATC. ALLETE's strategy is to remain predominately a regulated utility while investing in ALLETE Clean Energy, New Energy and its Corporate and Other businesses to complement its regulated businesses, balance exposure to the utility's industrial customers, and provide potential long-term earnings growth.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 150,000 retail customers. Minnesota Power also has 14 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Note 4. Regulatory Matters.)

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in seven states, more than 1,200 MW of nameplate capacity wind energy generation with a majority contracted under PSAs of various durations. In addition, ALLETE Clean Energy engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

Overview (Continued)

Corporate and Other is comprised of New Energy, a renewable development company; our investment in Nobles 2, an entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota; South Shore Energy, our non-rate regulated, Wisconsin subsidiary developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility; BNI Energy, our coal mining operations in North Dakota; ALLETE Properties, our legacy Florida real estate investment; other business development and corporate expenditures; unallocated interest expense; a small amount of non-rate base generation; land holdings in Minnesota; and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2023, unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	**2023**	**2022**	**2021**
Consolidated Operating Revenue – Millions *(a)*	$1,879.8	$1,570.7	$1,419.2
Percentage of Consolidated Operating Revenue			
Regulated Operations	66 %	80 %	87 %
ALLETE Clean Energy *(a)*	22 %	8 %	6 %
Corporate and Other *(b)*	12 %	12 %	7 %
	100 %	100 %	100 %

(a) Consolidated operating revenue for 2023 includes the sales of ALLETE Clean Energy’s Northern Wind and Red Barn projects.
(b) Consolidated operating revenue for 2023 and 2022 includes revenue from New Energy, which was acquired in the second quarter of 2022. (See Note. 5 Acquisitions.)

For a detailed discussion of results of operations and trends, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies and Note 14. Business Segments.

REGULATED OPERATIONS

Electric Sales / Customers

Regulated Utility Kilowatt-hours Sold Year Ended December 31	2023	%	2022	%	2021	%
Millions						
Retail and Municipal						
Residential	1,089	8	1,148	9	1,135	7
Commercial	1,347	11	1,359	11	1,359	9
Industrial	7,044	55	6,745	52	7,196	47
Municipal	466	4	540	4	590	4
Total Retail and Municipal	9,946	78	9,792	76	10,280	67
Other Power Suppliers	2,819	22	3,149	24	5,102	33
Total Regulated Utility Kilowatt-hours Sold	12,765	100	12,941	100	15,382	100

Industrial Customers. In 2023, industrial customers represented 55 percent of total regulated utility kWh sales. Our industrial customers are primarily in the taconite mining, paper, pulp and secondary wood products, and pipeline industries. Cliffs idled all production at its Northshore mine in 2022 and resumed partial pellet plant production in April 2023. (See Outlook – Regulated Operations – Industrial Customers – Taconite.)

Industrial Customer Kilowatt-hours Sold Year Ended December 31	2023	%	2022	%	2021	%
Millions						
Taconite	4,935	70	4,713	70	5,281	73
Paper, Pulp and Secondary Wood Products	669	10	735	11	702	10
Pipelines and Other Industrial	1,440	20	1,297	19	1,213	17
Total Industrial Customer Kilowatt-hours Sold	7,044	100	6,745	100	7,196	100

Six taconite facilities served by Minnesota Power made up approximately 70 percent of 2022 iron ore pellet production in the U.S. according to data from the Minnesota Department of Revenue 2023 Mining Tax Guide. These taconite facilities are owned by Cliffs and USS Corporation. (See *Large Power Customer Contracts*.) Sales to taconite customers represented 4,935 million kWh, or 70 percent of total industrial customer kWh sales in 2023. Taconite, an iron bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets.

Minnesota Power's taconite customers are capable of producing approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry, which continue to lead the world in environmental performance among steelmaking countries. According to the U.S. Department of Energy, steel production in the U.S. is the most energy efficient of any major steel producing country. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, tubular applications for all industries, and in the construction industry. Steel is also a critical component of the clean energy transformation underway today. The demand for more renewable energy and the need for additional infrastructure to transport green energy from the point of generation to the end user both require steel. Historically, approximately 10 percent of Minnesota taconite production has been exported outside of North America.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 75 percent of capacity in 2023 (78 percent in 2022 and 82 percent in 2021). The World Steel Association, an association of steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2024 will increase by approximately 2 percent compared to 2023.

The following table reflects Minnesota Power's taconite customers' production levels for the past ten years:

Minnesota Power Taconite Customer Production	
Year	**Tons (Millions)**
2023*	35
2022	32
2021	39
2020	30
2019	37
2018	39
2017	38
2016	28
2015	31
2014	39

Source: Minnesota Department of Revenue 2023 Mining Tax Guide for years 2014 - 2022.

** Preliminary data from the Minnesota Department of Revenue.*

Minnesota Power's taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in Minnesota Power's taconite customers' production would impact our annual earnings per share by approximately $0.05, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

In addition to serving the taconite industry, Minnesota Power serves a number of customers in the paper, pulp and secondary wood products industry, which represented 669 million kWh, or 10 percent of total industrial customer kWh sales in 2023. Minnesota Power also has an agreement to provide steam for one paper and pulp customer for use in the customer's operations. The major paper and pulp mills we serve reported operating at similar levels in 2023 compared to 2022. ST Paper completed start-up of operations and is now a Large Power Customer as of the first quarter of 2023. On January 3, 2024, ST Paper announced it had entered into an asset purchase agreement to sell the Duluth Mill to Sofidel (See Outlook – Regulated Operations – Industrial Customers – Paper, Pulp and Secondary Wood Products – ST Paper.)

Large Power Customer Contracts. Minnesota Power had eight Large Power Customer contracts as of December 31, 2023, each serving requirements of 10 MW or more of customer load. Certain facilities with common ownership are served under combined contracts. The customers as of December 31, 2023 consisted of six taconite facilities owned by Cliffs and USS Corporation as well as four paper and pulp mills. Minnesota Power also serves Northshore Mining through a PSA with its affiliate Silver Bay Power, in addition to the load served through its Large Power Contract with United Taconite and Northshore Mining. (See *Silver Bay Power PSA*.)

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a three- to four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kWh used that recovers the variable costs incurred in generating electricity. Five of the Large Power Customer contracts have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The required advance notice of cancellation varies from two to four years. Such contracts reduce the impact on earnings that otherwise would result from significant reductions in kWh sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See *Regulatory Matters – Electric Rates*.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills or make weekly prepayments based on Minnesota Power's estimate of the customer's energy usage, forecasted energy prices and fuel adjustment clause estimates. Minnesota Power's taconite producing Large Power Customers have generally predictable energy usage on a week-to-week basis and any differences that occur are trued-up the following month.

Contract Status for Minnesota Power Large Power Customers
As of December 31, 2023

Customer	Industry	Location	Ownership	Earliest Termination Date
Cliffs – Minorca Mine *(a)*	Taconite	Virginia, MN	Cliffs	December 31, 2027
Hibbing Taconite *(a)(d)*	Taconite	Hibbing, MN	85.3% Cliffs 14.7% USS Corporation	December 31, 2027
United Taconite and Northshore Mining *(a)*	Taconite	Eveleth, MN and Babbitt, MN	Cliffs	December 31, 2027
USS Corporation (USS – Minnesota Ore) *(a)(b)(d)*	Taconite	Mtn. Iron, MN and Keewatin, MN	USS Corporation	December 31, 2027
Boise, Inc. *(a)*	Paper	International Falls, MN	Packaging Corporation of America	December 31, 2027
UPM Blandin	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	December 31, 2029
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	December 31, 2027
ST Paper Duluth *(c)*	Paper	Duluth, MN	ST Paper LLC	February 28, 2029

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is December 31, 2027.

(b) USS Corporation owns both the Minntac Plant in Mountain Iron, MN, and the Keewatin Taconite Plant in Keewatin, MN.

(c) In January 2024, ST Paper announced it had entered into an asset purchase agreement to sell its paper mill in Duluth, Minnesota to Sofidel. (See Outlook – Regulated Operations – Industrial Customers – Paper, Pulp and Secondary Wood Products.)

(d) In December 2023, USS Corporation announced it entered into a definitive agreement in which Nippon Steel will acquire all of USS Corporation's stock. (See Outlook – Regulated Operations – Industrial Customers – Taconite.)

Silver Bay Power PSA. Minnesota Power has a PSA with Silver Bay Power through 2031 to supply its full energy requirements. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power.

Residential and Commercial Customers. In 2023, residential and commercial customers represented 19 percent of total regulated utility kWh sales.

Municipal Customers. In 2023, municipal customers represented 4 percent of total regulated utility kWh sales.

Minnesota Power's wholesale electric contracts with 14 non-affiliated municipal customers in Minnesota have termination dates ranging from 2029 through 2037, with a majority of contracts expiring in 2029. One of these wholesale contracts includes a termination clause requiring a 3-year notice to terminate. (See Note 4. Regulatory Matters.)

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are at market based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Our PSAs are detailed in Note 9. Commitments, Guarantees and Contingencies, with additional disclosure provided in the following paragraphs.

Minnkota Power PSA. Minnesota Power has a PSA with Minnkota Power where Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025. Of Minnesota Power's 50 percent output entitlement, it sold approximately 37 percent to Minnkota Power in 2023 (32 percent in 2022 and 28 percent in 2021). Minnkota Power's net entitlement increases to approximately 41 percent in 2024, 46 percent in 2025 and 50 percent in 2026. (See *Power Supply – Long-Term Purchased Power*.)

Hibbing Public Utilities. In April 2022, Minnesota Power entered into a long-term Power Purchase and Market Energy Service Agreement with Hibbing Public Utilities for the period of June 1, 2022, through May 31, 2027. The agreement replaced the previous wholesale electric contract between Hibbing Public Utilities and Minnesota Power.

Seasonality

The operations of our industrial customers, which make up a large portion of our electric sales, are not typically subject to significant seasonal variations. (See *Electric Sales / Customers*.) As a result, Minnesota Power is generally not subject to significant seasonal fluctuations in electric sales; however, Minnesota Power and SWL&P electric and natural gas sales to other customers may be affected by seasonal differences in weather. In general, peak electric sales occur in the winter and summer months with fewer electric sales in the spring and fall months. Peak sales of natural gas generally occur in the winter months. Additionally, our regulated utilities have historically generated fewer sales and less revenue when weather conditions are milder in the winter and summer.

Power Supply

In order to meet its customers' electric requirements, Minnesota Power utilizes a mix of its own generation and purchased power. Since 2020, approximately 50 percent of Minnesota Power's power supply for its retail and municipal customers in Minnesota has been provided by renewable energy sources. This was enabled by the completion of the 250 MW Nobles 2 wind energy facility in December 2020 and the GNTL in June 2020, which is used to deliver 250 MW of hydroelectric energy from Manitoba Hydro. Minnesota Power's remaining operating coal-fired facilities are Boswell Units 3 and 4, which Minnesota Power plans to cease coal operations at by 2030 and 2035, respectively. (See *Regulatory Matters*.) Renewable energy percentages may vary year to year based on weather, system demand and transmission constraints.

The following table reflects Minnesota Power's generating capabilities as of December 31, 2023, and total electrical supply for 2023. Minnesota Power had an annual net peak load of 1,551 MW on August 3, 2023.

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability		Year Ended December 31, 2023 Generation and Purchases	
			MW		MWh	%
Coal-Fired						
Boswell Energy Center *(a)*	3	1973	352			
in Cohasset, MN	4	1980	468	*(b)*		
			820		4,458,923	33.8
Total Coal-Fired			820		4,458,923	33.8
Biomass Co-Fired / Natural Gas						
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	60		68,189	0.5
Laskin Energy Center in Hoyt Lakes, MN	1 & 2	1953	98		110,290	0.8
Total Biomass Co-Fired / Natural Gas			158		178,479	1.3
Hydro *(c)*						
Group consisting of ten stations in MN	Multiple	Multiple	120		434,133	3.3
Wind *(d)*						
Taconite Ridge Energy Center in Mtn. Iron, MN	Multiple	2008	25		47,361	0.4
Bison Wind Energy Center in Oliver and Morton Counties, ND	Multiple	2010-2014	497		1,269,120	9.6
Total Wind			522		1,316,481	10.0
Solar *(e)*						
Group consisting of two solar arrays in MN	Multiple	Multiple	10		15,844	0.1
Total Generation			1,630		6,403,860	48.5
Long-Term Purchased Power						
Lignite Coal - Square Butte near Center, ND *(f)*					1,377,198	10.4
Wind - Oliver Wind I and II in Oliver County, ND					357,541	2.7
Wind - Nobles 2 in Nobles County, MN *(g)*					953,506	7.2
Hydro - Manitoba Hydro in Manitoba, Canada					1,460,000	11.1
Solar - Purchases from five solar arrays in MN					28,227	0.2
Total Long-Term Purchased Power					4,176,472	31.6
Other Purchased Power *(h)*					2,625,816	19.9
Total Purchased Power					6,802,288	51.5
Total Regulated Utility Power Supply					13,206,148	100.0

(a) Minnesota Power anticipates ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. (See Regulatory Matters.)
(b) Boswell Unit 4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of Boswell Unit 4. (See Note 3. Jointly-Owned Facilities and Assets.)
(c) Hydro consists of 10 stations with 34 generating units.
(d) Taconite Ridge consists of 10 WTGs and Bison consists of 165 WTGs.
(e) Solar includes the 10 MW Camp Ripley Solar Array near Little Falls, MN, and a 40 kW community solar garden in Duluth, MN.
(f) Minnesota Power has a PSA with Minnkota Power whereby Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power. (See Electric Sales / Customers – Minnkota Power PSA.)
(g) See Item 1. Business – Corporate and Other – Investment in Nobles 2.
(h) Includes short-term market purchases in the MISO market and from Other Power Suppliers.

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2023 for electric generation at Minnesota Power's coal-fired generating stations was 2.7 million tons (2.7 million tons in 2022; 2.7 million tons in 2021). As of December 31, 2023, Minnesota Power had coal inventories of 0.7 million tons (0.8 million tons as of December 31, 2022). Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2025. In 2024, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power continues to explore other future coal supply options and believes that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2024. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power **Year Ended December 31**	**2023**	**2022**	**2021**
Average Price per Ton	$41.23	$39.98	$39.51
Average Price per MBtu	$2.30	$2.25	$2.18

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities, including output from certain coal, wind, hydro and solar generating facilities.

Our PPAs are detailed in Note 9. Commitments, Guarantees and Contingencies, with additional disclosure provided in the following paragraph.

Square Butte PPA. Under the PPA with Square Butte that extends through 2026, Minnesota Power is entitled to 50 percent of the output of Square Butte's 455 MW coal-fired generating unit. (See Note 9. Commitments, Guarantees and Contingencies.) BNI Energy mines and sells lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite consumed in 2023 was approximately $2.36 per MBtu ($2.05 per MBtu in 2022; $1.94 per MBtu in 2021). (See *Electric Sales / Customers – Minnkota Power PSA*.)

Manitoba Hydro. Minnesota Power has two long-term PPAs with Manitoba Hydro. The first PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro through May 2035. The second PPA provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro through June 2040. A third PPA, which expired in April 2022 was an energy-only agreement, which primarily consisted of surplus hydro energy on Manitoba Hydro's system that was delivered to Minnesota Power on a non-firm basis.

Wind Energy. Minnesota Power has a long-term PPA with Nobles 2 that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwestern Minnesota through 2040. The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered. (See *Corporate and Other – Investment in Nobles 2*.) Minnesota Power also has two long-term wind energy PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) located in North Dakota.

Solar Energy. Minnesota Power purchases solar energy from approximately 20 MW of solar energy facilities located in Minnesota that are owned by an ALLETE subsidiary, and a 1 MW community solar garden in northeastern Minnesota, which is owned and operated by a third party.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (232 miles), 345 kV (241 miles), 250 kV (466 miles), 230 kV (715 miles), 161 kV (43 miles), 115 kV (1,380 miles) and less than 115 kV (6,415 miles). We own and operate 162 substations with a total capacity of 9,980 megavolt-amperes. Some of our transmission and distribution lines interconnect with other utilities, and we own some of our transmission lines jointly with other utilities. (See Note 3. Jointly-Owned Facilities and Assets and Outlook – Regulated Operations – Transmission.)

Great Northern Transmission Line. As a condition of the 250 MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity was required. As a result, Minnesota Power constructed the GNTL, an approximately 220-mile 500-kV transmission line between Manitoba and Minnesota's Iron Range that was proposed by Minnesota Power and Manitoba Hydro in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy. In June 2020, Minnesota Power placed the GNTL into service with project costs of approximately $310 million incurred by Minnesota Power. Total project costs, including those costs contributed by a subsidiary of Manitoba Hydro, totaled approximately $660 million. The 250 MW PPA with Manitoba Hydro commenced when the GNTL was placed into service.

Investment in ATC

Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. As of December 31, 2023, our equity investment in ATC was $179.7 million ($165.4 million as of December 31, 2022). (See Note 6. Equity Investments.)

ATC's authorized return on equity is 10.02 percent, or 10.52 percent including an incentive adder for participation in a regional transmission organization, based on a 2020 FERC order which is subject to various outstanding legal challenges related to the return on equity calculation and refund period ordered by the FERC. On August 9, 2022, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the 2020 FERC order back to the FERC. As a result of this decision, ATC recorded a reserve in the third quarter of 2022 for anticipated refunds to its customers for approximately $31 million of which our share was approximately $2.4 million pre-tax. We cannot predict the return on equity the FERC will ultimately authorize in the remanded proceeding.

In addition, the FERC issued a Notice of Proposed Rulemaking in April 2021 to limit the 50 basis point incentive adder for participation in a regional transmission organization to only the first three years of membership in such an organization. If this proposal is adopted, our equity in earnings from ATC would be reduced by approximately $1 million pre-tax annually.

ATC's most recent 10-year transmission assessment, which covers the years 2023 through 2032, identifies a need for between $6.6 billion and $8.1 billion in transmission system investments. These investments by ATC, if undertaken, are expected to be funded through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC.

Properties

Our Regulated Operations businesses own office and service buildings, an energy control center, repair shops, electric plants, transmission and distribution facilities and storerooms in various localities in Minnesota, Wisconsin and North Dakota. All of the electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Most of the generating plants and substations are located on real property owned by Minnesota Power or SWL&P, subject to the lien of a mortgage, whereas most of the transmission and distribution lines are located on real property owned by others with appropriate easement rights or necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 3. Jointly-Owned Facilities and Assets.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities and other organizations. Regulatory matters and proceedings are detailed in Note 4. Regulatory Matters, with a summary included in the following paragraphs.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by applicable regulatory authorities. Minnesota Power and SWL&P design their retail electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC or the PSCW. Nearly all retail sales include billing adjustment clauses, which may adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain transmission, renewable and environmental investments.

Minnesota Public Utilities Commission. The MPUC has regulatory authority over Minnesota Power's retail service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. Minnesota Power's retail base rates through 2021 were based on a 2018 MPUC retail rate order that allowed for a 9.25 percent return on common equity and a 53.81 percent equity ratio. Interim rates were implemented in Minnesota Power's 2022 general rate case beginning in January 2022, and the resolution of Minnesota Power's 2022 general rate case changed the allowed return on equity to 9.65 percent and the equity ratio to 52.50 percent beginning October 1, 2023. (See *2022 Minnesota General Rate Case*.) As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission and renewable investments.

2024 Minnesota General Rate Case. On November 1, 2023, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 12.00 percent for retail customers, net of rider revenue incorporated into base rates. The rate filing seeks a return on equity of 10.30 percent and a 53.00 percent equity ratio. On an annualized basis, the requested final rate increase would generate approximately $89 million in additional revenue. On December 7, 2023, the MPUC accepted the filing as complete and approved an annual interim rate increase of approximately $64 million, net of rider revenue, incorporated into base rates starting January 1, 2024, subject to refund. We cannot predict the level of final rates that may be authorized by the MPUC.

2022 Minnesota General Rate Case. On November 1, 2021, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 18 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $108 million in additional revenue.

In an order dated February 28, 2023, the MPUC made determinations regarding Minnesota Power's general rate case including allowing a return on common equity of 9.65 percent and a 52.50 percent equity ratio. We expect additional revenue from base rates of approximately $60 million and an additional $10 million in revenue recognized under cost recovery riders on an annualized basis. On March 20, 2023, Minnesota Power filed a petition for reconsideration with the MPUC requesting reconsideration and clarification of certain decisions in the MPUC's order. Minnesota Power's petition included requesting reconsideration of the ratemaking treatment of Taconite Harbor and Minnesota Power's prepaid pension asset as well as clarification on interim rate treatment for sales to certain customers that did not operate during 2022. The MPUC denied the requests for reconsideration in an order dated May 15, 2023, and provided clarification in support of the interim rate refund treatment for sales to certain customers that did not operate during 2022.

On June 14, 2023, Minnesota Power appealed to the Minnesota Court of Appeals (Court) specific aspects of the MPUC's rate case orders. Minnesota Power is appealing the ratemaking treatment of Taconite Harbor and Minnesota Power's prepaid pension asset. We are unable to predict the outcome of this proceeding.

In an order dated September 29, 2023, the MPUC approved Minnesota Power's final rates, which were implemented beginning on October 1, 2023. The MPUC order also approved Minnesota Power's interim rate refund plan. Interim rates were collected through the third quarter of 2023 with reserves recorded as necessary. Minnesota Power recorded a reserve for an interim rate refund of approximately $39 million pre-tax as of September 30, 2023 (approximately $18 million as of December 31, 2022). The reserve was refunded to customers during the fourth quarter of 2023.

Minnesota Power Land Sales. In August 2020, Minnesota Power filed a petition with the MPUC for approval to sell land that surrounds several reservoirs on its hydroelectric system and is no longer required to maintain its operations. The land had an estimated value of approximately $100 million, and Minnesota Power proposed to credit ratepayers the net proceeds from the sales in a future rate case or through its renewable resources rider to mitigate future rate increases. In an order dated November 18, 2021, the MPUC authorized the land sales and directed the net proceeds to be refunded to ratepayers subject to certain conditions and required compliance filings. As of December 31, 2023, we have a regulatory liability recorded of $30.2 million related to these sales.

2021 Integrated Resource Plan. On February 1, 2021, Minnesota Power filed its latest IRP, which was approved by the MPUC in an order dated January 9, 2023. The approved IRP, which reflects a joint agreement reached with various stakeholders, outlines Minnesota Power's clean-energy transition plans through 2035. These plans include expanding its renewable energy supply, achieving coal-free operations at its facilities by 2035, and investing in a resilient and flexible transmission and distribution grid. As part of these plans, Minnesota Power anticipates adding up to 700 MW of new wind and solar energy resources, and ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Minnesota Power's plans recognize that advances in technology will play a significant role in completing its transition to carbon-free energy supply, reliably and affordably. Minnesota Power is expected to file its next IRP by March 1, 2025.

Minnesota Power has a vision to deliver 100 percent carbon-free energy to customers by 2050, continuing its commitment to climate, customers and communities through its *EnergyForward* strategy. This vision builds on Minnesota Power's achievement, in 2020, of now providing 50 percent renewable energy to its customers.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas and water, issuances of securities and other matters. The resolution of SWL&P's 2022 general rate case changed the allowed return on equity to 10.00 percent and maintained an equity ratio of 55.00 percent beginning January 1, 2023. (See *2022 Wisconsin General Rate Case*.) SWL&P's retail rates through 2022 were based on a December 2018 order by the PSCW that allowed for a return on equity of 10.40 percent and a 55.00 percent equity ratio.

2022 Wisconsin General Rate Case. In 2022, SWL&P filed a rate increase request with the PSCW seeking an average increase of 3.60 percent for retail customers. The filing sought an overall return on equity of 10.40 percent and a 55.00 percent equity ratio. On an annualized basis, the requested final rate increase would have generated an estimated $4.3 million in additional revenue. In an order dated December 20, 2022, the PSCW approved an annual increase of $3.3 million reflecting a return on equity of 10.00 percent and 55.00 percent equity ratio. Final rates went into effect January 1, 2023.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities in North Dakota.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for transmission of electricity in interstate commerce, electricity sold at wholesale (including the rates for Minnesota Power's municipal and wholesale customers), natural gas transportation, certain accounting and recordkeeping practices, certain activities of our regulated utilities and the operations of ATC. FERC jurisdiction also includes enforcement of NERC mandatory electric reliability standards. Violations of FERC rules are subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

Regional Organizations

Midcontinent Independent System Operator, Inc. Minnesota Power, SWL&P and ATC are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission networks are under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. In cooperation with stakeholders, MISO manages the delivery of electric power across 15 states and the Canadian province of Manitoba.

North American Electric Reliability Corporation. The NERC has been certified by the FERC as the national electric reliability organization. The NERC ensures the reliability of the North American bulk power system. The NERC oversees six regional entities that establish requirements, approved by the FERC, for reliable operation and maintenance of power generation facilities and transmission systems. Minnesota Power is subject to these reliability requirements and can incur significant penalties for noncompliance.

Midwest Reliability Organization (MRO). Minnesota Power and ATC are members of the MRO, one of the six regional entities overseen by the NERC. The MRO's primary responsibilities are to: ensure compliance with mandatory reliability standards by entities which own, operate or use the interconnected, international bulk power system; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events. The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, and all or parts of 16 states.

Minnesota Legislation

Renewable and Carbon-Free Energy Requirements. On February 7, 2023, the Minnesota Governor signed into law legislation that updates the state’s renewable energy standard and requires Minnesota electric utilities to source retail sales with 100 percent carbon-free energy by 2040. The law increases the renewable energy standard from 25 percent renewable by 2025 to 55 percent renewable by 2035, and requires investor-owned Minnesota utilities to provide 80 percent carbon-free energy by 2030, 90 percent carbon-free energy by 2035 and 100 percent carbon-free energy by 2040. The law utilizes renewable energy credits as the means to demonstrate compliance with both the carbon-free and renewable energy standards, includes an off ramp provision that enables the MPUC to protect reliability and customer costs through modification or delay of either the renewable energy standard, the carbon-free standard, or both, and streamlines development and construction of wind energy projects and transmission in Minnesota. The Company is evaluating the law to identify challenges and opportunities it could present. Minnesota Power is also working with various stakeholders and participating in the regulatory process to implement this legislation.

Since 2020, approximately 50 percent of Minnesota Power’s power supply for its retail and municipal customers in Minnesota has been provided by renewable energy sources. Minnesota Power’s plans include expanding its renewable energy supply to 70 percent renewable energy by 2030. Minnesota Power has also set a target to achieve an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels. (See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions. Minnesota Power has met both parts of the solar mandate to date.

Competition

Retail electric energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users of 2 MW and above that are located outside of a municipality are allowed to choose a supplier upon MPUC approval. Minnesota Power served eight Large Power Customers under contracts of at least 10 MW in 2023, none of which have engaged in a competitive rate process. (See *Electric Sales / Customers.*) No other large commercial or small industrial customers in Minnesota Power’s service territory have sought a provider outside Minnesota Power’s service territory. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other forms of energy for their manufacturing processes.

In 2023, 4 percent of total regulated utility kWh sales were to municipal customers in Minnesota. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. Minnesota Power’s wholesale electric contract with the Nashwauk Public Utilities Commission is effective through 2037. Minnesota Power’s wholesale electric contracts with 13 other non-affiliated municipal customers are effective through 2029. (See *Electric Sales / Customers.*)

The FERC has continued with its efforts to promote a competitive wholesale market through open-access electric transmission and other means. As a result, our electric sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are made in a competitive market.

REGULATED OPERATIONS (Continued)

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 95 cities. The remaining cities, villages and towns served by Minnesota Power do not require a franchise to operate. SWL&P serves customers under electric, natural gas or water franchises in 1 city and 14 villages and towns.

ALLETE CLEAN ENERGY

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in seven states, more than 1,200 MW of nameplate capacity wind energy generation with a majority contracted under PSAs of various durations. In addition, ALLETE Clean Energy engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – ALLETE Clean Energy.)

ALLETE Clean Energy believes the market for renewable energy in North America is robust, driven by several factors including environmental regulation, tax incentives such as the extension of production tax credit and investment tax credits, societal expectations and continual technology advances. State renewable portfolio standards, state or federal regulations to limit GHG emissions and the extension of production tax credit and investment tax credits are examples of environmental regulation or public policy that we believe will drive renewable energy development.

ALLETE Clean Energy's strategy includes the safe, reliable, optimal and profitable operation of its existing facilities. This includes a strong safety culture, the continuous pursuit of operational efficiencies at existing facilities and cost controls. ALLETE Clean Energy generally acquires facilities in liquid power markets and its strategy includes the exploration of PSA extensions upon expiration of existing contracts, production tax credit requalification of existing facilities or the sale of facilities.

ALLETE Clean Energy manages risk by having a diverse portfolio of assets, which includes PSA expiration, technology and geographic diversity. The current operating portfolio is subject to typical variations in seasonal wind with higher wind resources typically available in the winter months. The majority of its planned maintenance leverages this seasonality and is performed during lower wind periods. ALLETE Clean Energy's current operating portfolio is as follows:

Region	Wind Energy Facility	Capacity MW	MW	PSA Expiration
East	Armenia Mountain	101		
	PSA 1		50%	2031
	PSA 2		50%	2024
Midwest	Lake Benton	104	100%	2028
	Storm Lake I	108	100%	2027
	Storm Lake II	77		
	Merchant		90%	n/a
	PSA		10%	2032
	Other	17	100%	2028
South	Caddo	303		
	Merchant		27%	n/a
	PSA 1		66%	2034
	PSA 2		7%	2034
	Diamond Spring	303		
	PSA 1		58%	2035
	PSA 2		25%	2032
	PSA 3		16%	2035
West	Condon	50	100%	2028
	Glen Ullin	106	100%	2039
	South Peak	80	100%	2035

The majority of ALLETE Clean Energy's wind operations are located on real property owned by others with easement rights or necessary consents of governmental authorities. One of ALLETE Clean Energy's wind energy facilities is encumbered by liens against its assets securing financing. ALLETE Clean Energy's Glen Ullin, South Peak, Diamond Spring and Caddo wind energy facilities are subject to tax equity financing structures. (See Note 1. Operations and Significant Accounting Policies.)

CORPORATE AND OTHER

New Energy

In April 2022, a wholly-owned subsidiary of ALLETE acquired 100 percent of the membership interests of New Energy for a purchase price of $165.5 million. New Energy, which is headquartered in Annapolis, Maryland, is a renewable energy development company with a primary focus on solar and storage facilities while also offering comprehensive operations, maintenance and asset management services. New Energy is a leading developer of community, commercial and industrial, and small utility-scale renewable energy projects that has completed more than 500 MW in its history, totaling more than $1.2 billion of capital. New Energy currently has a robust project pipeline with greater than 2,000 MW of renewable projects in development across over 20 different states. New Energy is involved in greenfield development as well as acquiring and completing mid-stage and late-stage renewable energy projects. New Energy will continue its current strategy of developing and operating renewable energy projects.

Investment in Nobles 2

Our subsidiary, ALLETE South Wind, owns a 49 percent equity interest in Nobles 2, the entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota pursuant to a 20-year PPA with Minnesota Power. As of December 31, 2023, our equity investment in Nobles 2 was $151.5 million ($157.3 million at December 31, 2022). (See Note 6. Equity Investments.)

South Shore Energy

South Shore Energy, ALLETE’s non-rate regulated, Wisconsin subsidiary, is developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy. Minnesota Power is expected to purchase approximately 20 percent of the facility's output starting in 2028 pursuant to a capacity dedication agreement. Construction of NTEC is subject to obtaining additional permits from local, state and federal authorities. The total project cost is estimated to be approximately $700 million, of which South Shore Energy will be responsible for approximately 20 percent. South Shore Energy’s portion of NTEC project costs incurred through December 31, 2023, is approximately $9 million.

BNI Energy

BNI Energy is a supplier of lignite coal in North Dakota, producing approximately 4 million tons annually and has an estimated 650 million tons of lignite coal reserves. Two electric generating cooperatives, Minnkota Power and Square Butte, consume virtually all of BNI Energy’s production of lignite under cost-plus fixed fee coal supply agreements extending through December 31, 2037. (See Item 1. Business – Regulated Operations – Power Supply – Long-Term Purchased Power and Note 9. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2023, BNI Energy’s total reclamation liability is estimated at $82.1 million, which is included in Other Non-Current Liabilities on the Consolidated Balance Sheet at its present value. These costs are included in the cost-plus fixed fee contract, for which an asset reclamation cost receivable was included in Other Non-Current Assets on the Consolidated Balance Sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 9. Commitments, Guarantees and Contingencies.)

ALLETE Properties

ALLETE Properties represents our legacy Florida real estate investment. ALLETE Properties’ major project in Florida is Town Center at Palm Coast, which consists of approximately 200 acres of land as well as various residential units and non-residential square footage. In addition to the Town Center at Palm Coast project, ALLETE Properties has approximately 500 acres of other land available for sale. (See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Outlook – Corporate and Other – ALLETE Properties.)

Seller Financing. ALLETE Properties occasionally provides seller financing to qualified buyers. As of December 31, 2023, outstanding finance receivables were $2.9 million, net of reserves, with maturities through 2027. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

Non-Rate Base Generation and Miscellaneous

Corporate and Other also includes other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, land holdings in Minnesota, and earnings on cash and investments.

As of December 31, 2023, non-rate base generation consists of 29 MW of natural gas and hydro generation at Rapids Energy Center in Grand Rapids, Minnesota, which is primarily dedicated to the needs of one customer, UPM Blandin, and approximately 20 MW of solar energy facilities located in Sylvan, Hoyt Lakes, and Duluth, Minnesota, which sell energy generated to Minnesota Power.

ENVIRONMENTAL MATTERS

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have been promulgated by both the EPA and state authorities over the past several years. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many state and federal environmental regulations and requirements finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of environmental regulations to project power supply trends and impacts on customers.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers. (See Note 9. Commitments, Guarantees and Contingencies.)

HUMAN CAPITAL MANAGEMENT

The Company's key human capital management objectives are to attract, recognize and retain high quality talent, align with strategic business objectives and support the Company's values. To support these objectives, the Company's programs are designed to develop talent; reward and support employees through competitive compensation programs and benefit plans; enhance the Company's culture through efforts aimed at making the workplace more engaging, safe and inclusive; and acquire talent and leverage internal opportunities to create a high-performing, diverse workforce. Our management, the ALLETE Board of Directors Executive Compensation and Human Capital Committee, and our Board of Directors as a whole play key roles in reviewing and overseeing our human capital practices.

As of December 31, 2023, ALLETE had 1,560 employees, of which 1,513 were full-time. We also respect employees' freedom of association and their right to collectively organize. As of December 31, 2023, Minnesota Power and SWL&P have an aggregate of 479 employees covered under collective bargaining agreements, of which most are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The current labor agreements with IBEW Local 31 expire on April 30, 2026, for Minnesota Power and January 31, 2027, for SWL&P. BNI Energy has 129 employees that are members of IBEW Local 1593. The current labor agreement with IBEW Local 1593 expires on March 31, 2026.

ALLETE's Human Rights Policy confirms our commitment to the advancement and protection of human rights, consistent with U.S. human rights laws and the general principles in the International Labour Organization Convention.

Integrity. Integrity is a foundational, shared value at ALLETE, is important to ALLETE's business and operations, and enables our success. The Company has a written Code of Business Conduct that applies to all of our employees, directors of ALLETE, contractors, vendors, and others who do business with or on behalf of ALLETE.

Health and Safety. The success of our business is fundamentally connected to the well-being of our people. Our journey to zero injury starts with a culture that is open and transparent. We encourage all employees to report injuries, near misses, and good catches, so that we can learn and share with others throughout the Company in an effort to improve safety performance. Leaders have regular safety conversations with employees, where hazard identification and controls are discussed to ensure work is being performed safely. To monitor progress, the Company uses leading and lagging indicators to analyze injury trends, safety participation and other data, such as data from our Company-wide safety perception survey to make better decision on safety practices.

Talent Attraction, Retention and Development. For more than a century, ALLETE has been successful because of our ability to attract and retain high-quality people who demonstrate our shared values. We engage in workforce planning, and succession planning, while building a robust talent pipeline and monitoring turnover.

We recognize and support the growth and development of our employees and offer opportunities to participate in internal and external learning programs. Our internal talent development programs provide employees with the resources they need to develop proficiency in their role, help achieve their career goals and build leadership skills. We are focusing initiatives on programs to expand the diversity of new hires and updating on-the-job trainings—including apprenticeships and scholarships aimed at bridging opportunity gaps—as we recognize the importance of a strong talent pipeline. In addition to role specific training, targeted training also includes respect in the workplace, cyber awareness, safety, integrity and leadership development.

Compensation and Benefits. Our competitive compensation package gives employees flexibility, choices and opportunities. Competitive compensation is important for the Company to attract and retain a qualified workforce to successfully manage our business and achieve our business objectives. We also strive to ensure pay equity among diverse employees performing equal or substantially similar work. Periodically, we review the median pay of our male and female employees as well as employees from diverse backgrounds.

Diversity, Equity and Inclusion. Increasing diversity enriches our workforce culture at ALLETE. Our employees are operating in an increasingly diverse society. In order to be accountable to our employees and stakeholders, we strive to have a workforce that reflects the diversity of the communities we serve, promotes inclusivity and is equitable.

At ALLETE, we want to ensure that we have a workplace culture where we treat each other with fairness, dignity and respect. The Company has a respect in the workplace initiative, which includes education as well as ongoing discussions focused on building respectful relationships and managing bias. We continue our efforts in crafting a framework to strengthen ALLETE's diversity, equity and inclusion efforts in the areas of: workforce, supply chain, communications, customers, and ALLETE as a community citizen. ALLETE continues to take tangible steps toward advancing diversity, equity and inclusion by continuing to raise awareness, furthering intentional external relationships/partnerships, increasing supplier diversity, focus on underrepresented groups through grants/scholarships and other Company and employee giving.

Yellow Ribbon Program. ALLETE and its subsidiaries are dedicated to supporting veterans, military members and their families. An employee effort grew out of that spirit of commitment to veterans and led the state of Minnesota to designate ALLETE/Minnesota Power and ALLETE Clean Energy as Yellow Ribbon Companies. The mission of ALLETE's Yellow Ribbon Program is to contribute to the Company's unique culture by proactively recruiting and retaining the best and supporting an environment in which military-connected employees can thrive.

AVAILABILITY OF INFORMATION

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE's website, www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

As of February 20, 2024, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Bethany M. Owen, Age 58	
Chair, President and Chief Executive Officer	May 11, 2021
President and Chief Executive Officer	February 3, 2020
President	January 31, 2019
Senior Vice President and Chief Legal and Administrative Officer	November 26, 2016
Patrick L. Cutshall, Age 58	
Vice President and Corporate Treasurer	December 18, 2017
Nicole R. Johnson, Age 49	
Vice President and President of ALLETE Clean Energy	August 22, 2022
Vice President and Chief Administrative Officer	June 28, 2019
Steven W. Morris, Age 62	
Senior Vice President and Chief Financial Officer	February 9, 2022
Vice President and Chief Accounting Officer	October 28, 2021
Vice President, Controller and Chief Accounting Officer	December 24, 2016
Joshua J. Skelton, Age 44	
Vice President and Chief Operating Officer of Minnesota Power	August 22, 2022
Margaret A. Thickens, Age 57	
Vice President, Chief Legal Officer and Corporate Secretary	February 13, 2019

All of the executive officers have been employed by us for more than five years in executive or management positions. Prior to election to the position listed above, the following executives held other positions with the Company during the past five years.

Ms. Johnson was Vice President – Human Resources.
Mr. Skelton was Chief Operating Officer of Minnesota Power, Vice President Generation Operations and ALLETE Safety.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed in the preceding table extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 14, 2024.

Item 1A. Risk Factors

The risks and uncertainties discussed below could materially affect our business operations, financial position, results of operations and cash flows, and should be carefully considered by stakeholders. The risks and uncertainties in this section are not the only ones we face; additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations, financial position, results of operations and cash flows. Accordingly, the risks described below should be carefully considered together with other information set forth in this report and in future reports that we file with the SEC.

Regulated Operations Risks

Our results of operations could be negatively impacted if our taconite, paper and pipeline customers experience an economic downturn, incur work stoppages, fail to compete effectively, experience decreased demand, fail to economically obtain raw materials, fail to renew or obtain necessary permits, or experience a decline in prices for their product.

Minnesota Power's Large Power Customers (see Item 1. Business – Regulated Operations – Electric Sales / Customers) and Silver Bay Power accounted for 24 percent of our 2023 consolidated operating revenue (29 percent in 2022 and 32 percent in 2021) and 36 percent of Regulated Operations operating revenue (36 percent in 2022 and 37 percent in 2021). Minnesota Power's taconite customers, which are currently owned by only two entities at the end of 2023, accounted for approximately 21 percent of consolidated operating revenue and 32 percent of Regulated Operations operating revenue in 2023. This concentrated ownership presents customer concentration risk for the Company, and could lead to further capacity consolidation for both steel blast furnaces and related Minnesota iron ore production. These customers are also involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the marketplace. The North American paper and pulp industry also faces declining demand due to the impact of electronic substitution for print and changing customer needs. As a result, certain paper and pulp customers have reduced their existing operations or idled facilities in recent years and have pursued or are pursuing product changes in response to declining demand. Additionally, the taconite industry could be impacted by changing technology in the steel industry such as the adoption of electric arc furnaces for steelmaking, which could result in declining demand for taconite and the electricity used during its production.

Minnesota Power also serves two pipeline customers that accounted for 2 percent of our 2023 consolidated operating revenue (2 percent in 2022 and in 2021) and 3 percent of Regulated Operations revenue in 2023 (2 percent in 2022 and 2021). These customers are involved in an industry that is seeing increased environmental pressure for construction of new or expanded pipeline infrastructure for the transportation of fossil fuels. Changes in regulatory rulings or permit proceedings could result in changes to operations of the pipeline network in our service territory.

Accordingly, if our industrial customers experience an economic downturn, incur a work stoppage (including strikes, lock-outs or other events), fail to compete effectively, experience decreased demand, fail to economically obtain raw materials or operate their facilities, fail to renew or obtain necessary permits, or experience a decline in demand or prices for their product, there could be adverse effects on their operations and, consequently, this could have a negative impact on our results of operations as we are unable to remarket at similar prices the energy that would otherwise have been sold to such customers.

We may not be able to successfully implement our strategic objectives of growing load at our utilities if current or potential industrial or municipal customers are unable to successfully implement expansion plans, including the inability to obtain necessary governmental permits and approvals.

As part of our long-term strategy, we pursue new wholesale and retail loads in and around our service territories. Currently, there are several companies in northeastern Minnesota that are in the process of developing natural resource-based projects that represent long-term growth potential and load diversity for our Regulated Operations businesses. These projects may include construction of new facilities and restarts of old facilities, both of which require permitting and approvals to be obtained before the projects can be successfully implemented. If a project does not obtain any necessary governmental (including environmental) permits and approvals or if these customers are unable to successfully implement expansion plans, our long-term strategy and thus our results of operations could be adversely impacted.

Our businesses, investments and customers are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

Our businesses, investments and customers are subject to an extensive legal and regulatory framework imposed under federal and state law including regulations administered by the FERC, MPUC, MPCA, PSCW, NDPSC and EPA as well as regulations administered by other organizations including the NERC. These laws and regulations relate to allowed rates of return, capital structure, financings, rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities), recovery of purchased power costs and capital investments, approval of integrated resource plans and present or prospective wholesale and retail competition, renewable portfolio standards that require utilities to obtain specified percentages of electric supply from eligible renewable generation sources, among other things. Energy policy initiatives at the state or federal level could increase or accelerate renewable and carbon-free energy standards or incentives for distributed generation, municipal utility ownership, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model. (See Item 1. Business – Regulated Operations – Minnesota Legislation.) Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. Compliance with these standards may lead to increased operating costs and capital expenditures which are subject to regulatory approval for recovery. If it was determined that we were not in compliance with these mandatory reliability standards or other statutes, rules and orders, we could incur substantial monetary penalties and other sanctions, which could adversely affect our results of operations.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary permits, licenses, approvals and certificates for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations, timing of approvals, the adoption of new regulations or the expansion of jurisdiction by these agencies and other organizations could have an adverse impact on our business and results of operations. In addition, our ability to manage changing regulations could be impacted by our rights and obligations under joint ownership agreements.

Our ability to obtain rate adjustments to maintain reasonable rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file general rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in general rate cases, including if rates are reduced, if increased rates are not approved or recovered on a timely basis, if fuel adjustment clause recoveries or cost recovery for other items are not granted at the requested level, or costs are otherwise unable to be recovered through rates, we may experience an adverse impact on our financial position, results of operations and cash flows. We are unable to predict the impact on our business and results of operations from future legislation or regulatory activities of any of these agencies or organizations.

Our regulated operations present certain environmental risks that could adversely affect our financial position and results of operations, including effects of environmental laws and regulations, physical risks associated with climate change and initiatives designed to reduce the impact of GHG emissions.

We are subject to extensive environmental laws and regulations affecting many aspects of our past, present and future operations, including air quality, water quality and usage, waste management, reclamation, hazardous wastes, avian mortality and natural resources. These laws and regulations, or new laws and regulations that may be passed, can result in increased capital expenditures and increased operating and other costs as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to emissions, coal ash and water discharge at generating facilities.

These laws and regulations could restrict the output of some existing facilities, limit the use of some fuels in the production of electricity, require the installation of additional pollution control equipment, require participation in environmental emission allowance trading, and lead to other environmental considerations and costs, which could have an adverse impact on our business, operations and results of operations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Violations of these laws and regulations could expose us to regulatory and legal proceedings, disputes with, and legal challenges by, governmental authorities and private parties, as well as potential significant civil fines criminal penalties and other sanctions.

Existing environmental regulations may be revised and new environmental regulations may be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have an adverse effect on our results of operations.

There is significant uncertainty regarding if and when new laws, regulations or administrative policies will be adopted to reduce or limit GHG and the impact any such laws or regulations would have on us. In 2023, our operating coal-fired generating facilities consisted of the 352 MW Boswell Unit 3 and the 468 MW Boswell Unit 4. (See Item 7. Management Discussion and Analysis of Financial Condition and Results of Operation – Outlook – EnergyForward.) Any future limits on GHG emissions at the federal or state level, or action taken by regulators, before these facilities are retired or become coal-free may require us to incur significant capital expenditures and increases in operating costs, or could result in early closure of coal-fired generating facilities, stranded assets, an impairment of assets, denial of full recovery of decommissioning costs in excess of amounts previously collected, or otherwise adversely affect our results of operations, particularly if resulting expenditures and costs are not fully recoverable from customers.

Our regulated operations may be adversely impacted by the physical and financial risks associated with climate change. See *Entity-wide Risks* for additional discussion of risks related to GHG and climate change.

We cannot predict the amount or timing of all future expenditures related to environmental matters because of uncertainty as to applicable regulations or requirements. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain environmental statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for noncompliance.

The operation and maintenance of our regulated electric generation, transmission and distribution facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The operation of generating facilities involves many risks, including start-up operational risks, breakdown or failure of facilities, the dependence on a specific fuel source, inadequate fuel supply, availability of fuel transportation, and the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. A significant portion of our facilities contain older generating equipment, which, even if maintained in accordance with good engineering practices, may require significant capital expenditures to continue operating at peak efficiency. Generation, transmission and distribution facilities and equipment are also likely to require periodic upgrades and improvements due to changing environmental standards and technological advances. Our ability to manage and operate certain facilities could also be impacted by our rights and obligations under the joint ownership agreements. We could be subject to costs associated with any unexpected failure to produce or deliver power, including failure caused by breakdown, forced outage or limited availability of fuel or fuel transportation, as well as the repair of damage to facilities due to breakdown, storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events. This could also lead to requiring additional purchased power to meet requirements of serving our retail load, which for Minnesota Power is subject to recovery under the fuel adjustment clause. Should these costs be denied or are otherwise unable to be recovered, our financial position, results of operations and cash flows could be adversely impacted.

Our ability to successfully and timely complete capital repairs or improvements to existing regulated facilities or in the development of new electric generation and transmission facilities or other capital projects is contingent upon many variables.

We expect to incur significant capital expenditures in making capital repairs or improvements to our existing electric generation and transmission facilities and in the development and construction of new electric generation and transmission facilities. Should any such efforts be unsuccessful, not completed in a timely manner, if we are unable to obtain the necessary permits, land rights and regulatory approvals, or if there are increases in the costs for or limited availability of key materials, supplies, labor and services, we could be subject to additional costs or impairments, and projects may be delayed or canceled which could have an adverse impact on our financial position, results of operation and cash flows.

Our regulated electric operations may not have access to adequate and reliable transmission and distribution facilities necessary to deliver electricity to our customers.

We depend on our own transmission and distribution facilities, as well as facilities owned by other utilities, to deliver the electricity sold to our customers, and to other energy suppliers. If transmission capacity is inadequate or transmission and distribution facilities we rely on are damaged, our ability to sell and deliver electricity may be limited. We may have to forgo sales or may have to buy more expensive wholesale electricity that is available in a capacity-constrained area. The ability to restore adequate capacity or repair damaged infrastructure may be impacted by the availability of key materials, supplies, labor and services, which if unavailable may prolong the impact of capacity constraints or damaged facilities. In addition, any infrastructure failure or damage that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers, which could have an adverse impact on our business and results of operations.

The price of electricity may be volatile and fuel may be volatile and availability may be limited.

Volatility in market prices for electricity and volatility and limited availability of fuel could adversely impact our financial position and results of operations and may result from:

- severe or unexpected weather conditions and natural disasters;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at our generating facilities or those of our competitors;
- availability of fuel and transportation of fuel;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- wars, sabotage, terrorist acts, cybersecurity attacks or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Volatility in market prices for our fuel and purchase power costs impacts our sales to retail, municipal and Other Power Suppliers. Fluctuations in our fuel and purchased power costs related to our retail and municipal customers are passed on to customers through the fuel adjustment clause; however, our results of operations and cash flows may be adversely impacted if increased fuel adjustment clause rates are not approved or recovered on a timely basis, if cost recovery is not granted at the requested level, or costs are otherwise unable to be recovered through the fuel adjustment clause.

Wholesale prices for electricity have also declined in recent years primarily due to the extension of renewable tax credits and additional renewable generation commencing operations. If there are reductions in demand from current customers, we lose retail customers, or we lose municipal customers that do not renew existing contracts, we will market any available power to Other Power Suppliers in an effort to mitigate any earnings impact. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. Due to wholesale prices for electricity being below our rates for retail and municipal customers, we do not expect that our power marketing efforts would fully offset the reduction in earnings resulting from the lower demand from existing customers or the loss of customers. (See Item 1. Business – Regulated Operations – Electric Sales / Customers.)

Demand for energy may decrease.

Our results of operations are impacted by the demand for energy in our service territories, our municipal customers and other power suppliers. There could be lower demand for energy due to a loss of customers as a result of economic conditions, customers constructing or installing their own generation facilities, higher costs and rates charged to customers, eligible municipal and other power suppliers choosing an alternative energy provider, or loss of service territory or franchises. Further, energy conservation and technological advances that increased energy efficiency may temporarily or permanently reduce the demand for energy products. In addition, we are impacted by state and federal regulations requiring mandatory conservation measures, which reduce the demand for energy products. Continuing technology improvements and regulatory developments may make customer and third party-owned generation technologies such as rooftop solar systems, WTGs, microturbines and battery storage systems more cost effective and feasible for certain customers. If customers utilize their own generation, demand for energy from us would decline. There may not be future economic growth opportunities that would enable us to replace the lost energy demand from these customers. Therefore, a decrease in demand for energy could adversely impact our financial position, results of operations and cash flows.

ALLETE Clean Energy / Corporate and Other Risks

The inability to successfully manage and grow our businesses could adversely affect our results of operations.

The Company's strategy includes adding customers, new geographies, and growth through acquisitions or project development with long-term PSAs in place for the output or to be sold upon completion. This strategy depends, in part, on the Company's ability to successfully identify and evaluate acquisition or development opportunities and consummate acquisitions on acceptable terms and obtain all required permits and approvals. The Company may compete with other companies for these acquisition and development opportunities, which may increase the Company's cost of making acquisitions and the Company may be unsuccessful in pursuing these acquisition opportunities. Other companies may be able to pay more for acquisitions and may be able to identify, evaluate, bid for and purchase a greater number of assets than the Company's financial or human resources permit. New laws and regulations promoting renewable energy generation may result in increased competition. Our ALLETE Clean Energy business is experiencing return pressures from increased competition, and lower forward price curves, as a growing amount of investment capital is being directed into wind energy generation opportunities. In addition, current and potential new project developments at our businesses can be negatively affected by a lower ALLETE stock price, which may result in such projects not being accretive, or otherwise unable to satisfy our financial objectives criteria to proceed. Additionally, tax law changes may adversely impact the economic characteristics of potential acquisitions or investments. If the Company is unable to execute its strategy of growth through acquisitions, project development for others, or the addition of new customers and geographies, it may impede our long-term objectives and business strategy.

Acquisitions and operations of recently acquired entities are subject to uncertainties. If we are unable to successfully integrate and manage New Energy, or future acquisitions and strategic investments, this could have an adverse impact on our results of operations. Our actual results may also differ from our expectations due to factors such as the ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

Our results of operations could be adversely affected by changes in governmental incentives or policies that support renewable energy or changes in taxes, tariffs, duties or other assessments on renewable energy or the equipment necessary to generate and deliver it.

Any reductions or modifications to, or the elimination of, governmental incentives or policies that support renewable energy, or the imposition of additional or increased sourcing of components subject to taxes, tariffs, duties or other assessments on renewable energy or the equipment necessary to generate and deliver it, could result in, among other items, the lack of a satisfactory market for the development or financing of new renewable energy projects and reduced project returns on current or future projects.

The U.S. government currently imposes anti-dumping and countervailing duties on certain imported photovoltaic (PV) cells and modules from China and Taiwan. Such duties can change over time pursuant to annual reviews conducted by the U.S. Department of Commerce (DOC). On August 18, 2023, the U.S. DOC issued a final affirmative determination that imports of certain PV cells and modules assembled and completed in Cambodia, Malaysia, Thailand, and Vietnam are circumventing anti-dumping and countervailing duties. Duties will not be collected on imports before June 2024 as a result of a temporary duty suspension ordered by the U.S. President. Our operating results could be adversely impacted if this U.S. DOC circumvention determination results in duties assessed on future purchases made by our businesses after the current moratorium ends, or if additional anti-dumping and countervailing duties are imposed by the U.S. government on products purchased by our businesses.

The generation of electricity from wind and solar energy facilities depends heavily on suitable meteorological conditions.

Although our electric generation facilities are located in diverse geographic regions to reduce the potential impact that may be caused by unfavorable weather in a particular region, suitable meteorological conditions are variable and difficult to predict. If wind or solar conditions are unfavorable or meteorological conditions are unsuitable, electricity generation and revenue from wind and solar energy facilities may be substantially below our expectations. The electricity produced, production tax credits received, and revenues generated by a wind or solar energy facility are highly dependent on suitable wind conditions and associated weather conditions, which are variable and beyond our control. We base our decisions about which wind and solar projects to build or acquire as well as our electricity generation estimates, in part, on the findings of long-term wind and other meteorological studies conducted on the project site and its region; however, the unpredictable nature of wind and solar conditions, weather and meteorological conditions can result in material deviations from these studies and our expectations. Furthermore, components of our systems could be damaged by severe weather, such as hailstorms, lightning or tornadoes. In addition, replacement and spare parts for key components may be difficult or costly to acquire or may be unavailable. Unfavorable wind and solar conditions, weather or changes to meteorological patterns could impair the effectiveness of our electric generation facility assets, reduce their output beneath their rated capacity or require shutdown of key equipment, impeding operation of our wind energy facilities or lead to an impairment of assets.

The construction, operation and maintenance of our electric generation facilities or investment in facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The construction and operation of generating facilities involves many risks, including the performance by key contracted suppliers and maintenance providers; increases in the costs for or limited availability of key materials, supplies, labor and services; start-up operations risks; breakdown or failure of facilities; curtailment of facilities by counterparties or due to inadequate transmission capacity; the dependence on the availability of wind resources; or the impact of unusual, adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. Some of our facilities contain older generating equipment, which even if maintained in accordance with good engineering practices, may require significant capital expenditures to continue operating at peak efficiency. We could be subject to costs associated with any unexpected failure to produce and deliver power, including failure caused by breakdown or forced outage, as well as the repair of damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events.

The price of electricity may be volatile, which may impact results of operations at ALLETE Clean Energy wind energy facilities under contracts with commercial and industrial (C&I) customers.

Unusual, adverse weather conditions or other natural events and different settlement prices between hub and node can cause volatility in market prices for electricity and adversely affect our financial position, results of operations and cash flows. ALLETE Clean Energy's power sales agreements with C&I customers at its Diamond Spring and Caddo wind energy facilities are contracts for differences where power is delivered to the market, a fixed price is paid by the customers to ALLETE Clean Energy, and differences between the market price and the fixed price are paid to or received from the customers. Certain contracts also settle with the market at the hub price whereas ALLETE Clean Energy settles with the customer at the node price which can vary significantly based on multiple factors. These settlement provisions can result in an adverse impact on our financial position, results of operations and cash flows when market prices are volatile, or lead to potential impairment of property, plant and equipment if these conditions persist for an extended period of time.

As contracts with counterparties expire, we may not be able to replace them with agreements on similar terms or divest the related assets at a profit.

ALLETE Clean Energy is party to PSAs that expire in various years between 2024 and 2039. These PSA expirations are prior to the end of the estimated useful lives of the respective wind energy facilities. If, for any reason, ALLETE Clean Energy is unable to enter into new agreements with existing or new counterparties on similar terms once the current agreements expire, sell energy in the wholesale market resulting in similar revenue, or enter into a contract to sell the facility at a profit, our financial position, results of operations and cash flows could be adversely affected, which includes potential impairment of property, plant and equipment.

Counterparties to turbine and other generation supply, service and maintenance, or power sale agreements may not fulfill their obligations.

Our businesses are party to turbine and other generation supply agreements, service and maintenance agreements, and PSAs under various durations with a limited number of creditworthy counterparties. If, for any reason, any of the counterparties under these agreements do not fulfill their related contractual obligations, and we are unable to mitigate non-performance by a key supplier or maintenance provider or remarket PSA energy resulting in similar revenue, our financial position, results of operations and cash flows could be adversely affected.

ALLETE has a significant amount of goodwill. A determination that goodwill has been impaired could result in a significant non-cash charge to earnings.

We had approximately $155 million of goodwill recorded on our Consolidated Balance Sheet as of December 31, 2023, related to New Energy. If we change our business strategy, fail to deliver on our projected results or if market or other conditions adversely affect the operations of New Energy, we may be required to record an impairment charge. Declines in projected operating cash flows at New Energy could also result in an impairment charge. An impairment charge would result in a non-cash charge to earnings that could have an adverse effect on our results of operations.

BNI Energy may be adversely impacted by its exposure to customer concentration, and environmental laws and regulations.

BNI Energy sells lignite coal to two electric generating cooperatives, Minnkota Power and Square Butte, and could be adversely impacted if these customers were unable or unwilling to fulfill their related contractual obligations, or change the way in which they operate their generating facilities. In addition, BNI Energy and its customers may be adversely impacted by existing or new environmental laws and regulations which could have an adverse effect on our financial position, results of operations and cash flows. In addition, insurance companies have decreased the available coverage for policy holders in the mining industry, impacting the availability of coverage, and leading to higher deductibles and premiums.

Real estate market conditions where our legacy Florida real estate investment is located may deteriorate.

The Company’s strategy related to the real estate assets of ALLETE Properties incorporates the possibility of a bulk sale of its entire portfolio, in addition to sales over time, however, adverse market conditions could impact the timing of land sales, which could result in little to no sales, while still incurring operating expenses such as community development district assessments and property taxes, resulting in net operating losses at ALLETE Properties. Furthermore, weak market conditions could put the properties at risk for an impairment charge. An impairment charge would result in a non-cash charge to earnings that could have an adverse effect on our results of operations.

Entity-wide Risks

We could be materially adversely affected by health epidemics, pandemics and other outbreaks.

Health epidemics, pandemics and other outbreaks, as well as the related federal and state government responses, can have widespread impacts on the economy and on our employees, customers, contractors and suppliers, such as those experienced from the COVID-19 pandemic. There may be uncertainty regarding the length of time an epidemic, pandemic or other outbreak will last, how they will evolve, or the extent and duration of any measures attempted to try and contain them.

A disruption of economic activity or an extended disruption of economic activity may lead to adverse impacts on our taconite, paper, pulp and secondary wood products, and pipeline customers' operations including reduced production or the temporary idling or indefinite shutdown of facilities, which would result in lower sales and revenue from these customers. A disruption in capital markets could lead to increased borrowing costs or adversely impact our ability to access capital markets or other financing sources, which would adversely affect our ability to maintain our businesses or to implement our business plans. An epidemic, pandemic or other outbreak may also result in a disruption to our supply chains which could adversely impact our operations and capital projects resulting in project and operational delays, project cancellations, lower returns on projects and cost increases.

Despite any efforts made to mitigate the impacts on the Company of an epidemic, pandemic or other outbreak, their ultimate impact also depends on factors beyond our control, including their duration and severity as well as governmental and third-party actions taken to contain their spread and mitigate their public health effects. As a result, we cannot predict the ultimate impact of an epidemic, pandemic or other outbreak, such as the ongoing COVID-19 pandemic and whether it will have a material impact on our liquidity, financial position, results of operations and cash flows.

We rely on access to financing sources and capital markets. If we do not have access to capital on acceptable terms or are unable to obtain capital when needed, our ability to execute our business plans, make capital expenditures or pursue other strategic actions that we may otherwise rely on for future growth would be adversely affected.

We rely on access to financing sources and the capital markets, on acceptable terms and at reasonable costs, as sources of liquidity for capital requirements not satisfied by our cash flows from operations. Rising interest rates, inflation and market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access and finance in the capital markets or to access other financing sources such as tax equity financing. Such disruptions or causes of a downgrade could include but are not limited to: weakening of the Company's cash flow metrics; a loss of, or a reduction in sales to, our taconite, paper and pipeline customers if we are unable to offset the related lost margins; weaker operating performance; adverse regulatory outcomes; disproportionate increase in the contribution to net income from ALLETE Clean Energy and our Corporate and Other businesses as compared to that from our Regulated Operations; deteriorating economic or capital market conditions; or volatility in commodity prices.

If we are not able to access capital on acceptable terms in sufficient amounts and when needed, or at all, the ability to maintain our businesses or to implement our business plans would be adversely affected. This would include our ability to make the significant capital expenditures planned in order to achieve Minnesota Power's clean-energy transition plans. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements.)

A deterioration in general economic conditions, an inflationary environment or supply chain disruptions may have adverse impacts on our financial position, results of operations and cash flows.

If economic conditions deteriorate, we experience an inflationary environment or supply chains are disrupted on a national, regional or global level, it may have a negative impact on our customers and the Company's financial position, results of operations and cash flows. This impact may include volatility and unpredictability in the demand for the products and services offered by our businesses, the loss of existing customers, tempered growth strategies, customer production cutbacks, customer bankruptcies and increases in costs for or limited availability of key materials, supplies, labor and services for our operations and capital projects. An uncertain economy could also adversely affect expenses including pension costs, interest costs, and uncollectible accounts, or lead to reductions in the value of certain real estate and other investments.

Our utility infrastructure and generating facilities, ongoing and future capital and development projects, and other operations require components, supplies, materials, labor and services sourced from suppliers or providers who, in turn, may source components from their suppliers. A shortage of key components, supplies, materials, labor or services in which an alternative supplier or provider is not identified could significantly impact project plans or our operations. Such impacts could include project delays, including potential for project cancellation, lower project returns, increased costs or the inability to provide service to customers, which could adversely impact our results of operations, financial condition or cash flows.

Our businesses, investments and customers are subject to extensive state and federal legislation and regulation, compliance with which could have an adverse effect on our businesses.

Our businesses, investments and customers are subject to, and affected by, extensive state and federal legislation and regulation. If it was determined that our businesses failed to comply with applicable laws and regulations, we could become subject to fines or penalties or be required to implement additional compliance measures or actions, the cost of which could be material. If we are unable to obtain all required permits and approvals for our development projects, it could negatively impact our ability to execute on our *EnergyForward* strategy. Adoption of new laws, rules, regulations, principles, or practices by federal and state agencies, or changes to or a failure to comply with current laws, rules, regulations, principles, or practices and their interpretations, could have an adverse effect on our financial position, results of operations and cash flows.

The inability to attract and retain a qualified workforce including, but not limited to, executive officers, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce, including, but not limited to, executive officers, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures, inflation or terms of collective bargaining agreements with union employees.

Market performance and other changes could decrease the value of pension and other postretirement benefit plan assets, which may result in significant additional funding requirements and increased annual expenses.

The performance of the capital markets impacts the values of the assets that are held in trust to satisfy future obligations under our pension and other postretirement benefit plans. We have significant obligations to these plans and the trusts hold significant assets. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and other postretirement benefit plan assets would increase the funding requirements under our benefit plans if asset returns do not recover. Additionally, our pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and other postretirement benefit plan costs are generally recoverable in our electric rates as allowed by our regulators or through our cost-plus fixed fee coal supply agreements at BNI Energy; however, there is no certainty that regulators will continue to allow recovery of these rising costs in the future.

We are exposed to significant reputational risk.

The Company could suffer negative impacts to its reputation as a result of operational incidents, violations of corporate compliance policies, such as our code of business conduct, by employees, directors of ALLETE, contractors, vendors and others who do business with or on behalf of ALLETE, regulatory violations, operations that produce or enable the production of GHG emissions or other events which may result in negative customer perception, increased regulatory oversight, and negative consequences to our credit ratings and ability to access capital, each of which could have an adverse effect on our financial position, results of operations and cash flows.

We are subject to physical and financial risks associated with climate change and other catastrophic events, such as natural disasters and acts of war.

Catastrophic events at or near Company facilities and equipment on which the Company depends upon or that otherwise impact the Company such as fires, wildfires, including the impact to Company facilities and operations or potential liability if caused by Company equipment, earthquakes, explosions, and floods, severe weather, such as ice storms, hailstorms, or tornadoes or similar occurrences, as well as acts of war, could adversely affect the Company's facilities, operations, financial position, results of operations and cash flows. Although the Company has contingency plans and employs crisis management to respond and recover operations in the event of a severe disruption resulting from a catastrophic event, these measures may not be successful. Furthermore, despite these measures, if a catastrophic event were to occur, our financial position, results of operations and cash flows could be adversely affected.

The scientific community generally accepts that emissions of GHG are linked to global climate change. Physical risks of climate change, such as more frequent, longer duration or more extreme weather events, changes in temperature and precipitation patterns, increased risk of wildfires, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs or limit the availability of key materials, supplies, labor and services used in our operations or to respond to damaged facilities. An extreme weather event can also directly affect our capital assets, causing disruption in service to customers due to facility outages, downed wires and poles or damage to other operating equipment.

Climate-related risks that could adversely affect our financial position and results of operations include effects of environmental- or economic-based laws, regulations, incentives or initiatives designed to reduce the quantity or impact of GHG emissions, the ability of our regulated businesses to obtain rate adjustments to recover costs and investments to implement clean-energy transition plans, or disruptions to the economy or energy markets caused by climate change. This includes the risk of laws or regulations that create mandates that do not allow for a transition that protects the safety, reliability or affordability of energy for our customers, are implemented before cost-effective technology is developed and regulatory policy is established, or require the electric sector to decarbonize faster than other sectors and ahead of our current vision to deliver 100 percent carbon-free energy to customers by 2050. Additionally, restrictions on land use, wildlife impacts, and other environmental regulations could affect the siting, construction and operation of new or existing generation and transmission facilities needed to transition to lower-carbon generation sources.

These all have the potential to adversely affect our business and operations.

We are vulnerable to acts of terrorism or cybersecurity attacks.

Our operations may be targets of terrorist activities or cybersecurity attacks, which could disrupt our ability to provide utility service at our regulated utilities, develop or operate our renewable energy projects at ALLETE Clean Energy, or operate our other businesses. The impacts may also impair the fulfillment of critical business functions, negatively impact our reputation, subject us to litigation or increased regulation, or compromise sensitive, confidential and other data.

There have been cybersecurity attacks on U.S. energy infrastructure in the past and there may be such attacks in the future. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems could be direct targets of, or otherwise be materially adversely affected by such activities. Hacking, computer viruses, terrorism, theft and sabotage could impact our systems and facilities, or those of third parties on which we rely, which may disrupt our operations.

Our businesses require the continued operation of sophisticated custom-developed, purchased, and leased information technology systems and network infrastructure as well as the collection and retention of personally identifiable information of our customers, shareholders and employees. Although we maintain security measures designed to prevent cybersecurity incidents and protect our information technology and control systems, network infrastructure and other assets, our technology systems, or those of third parties on which we rely, may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism as well as other causes. If those technology systems fail or are breached and not recovered in a timely manner, we may be unable to perform critical business functions including effectively maintaining certain internal controls over financial reporting, our reputation may be negatively impacted, we may become subject to litigation or increased regulation, and sensitive, confidential and other data could be compromised. If our business were impacted by terrorist activities or cybersecurity attacks, such impacts could have an adverse effect on our financial position, results of operations and cash flows.

We maintain insurance against some, but not all, of the risks and uncertainties we face.

We maintain insurance against some, but not all, of the risks and uncertainties we face. The occurrence of these risks and uncertainties, if not fully covered by insurance, could have a material effect on our financial position, results of operations and cash flows.

Government challenges to our tax positions, as well as tax law changes and the inherent difficulty in quantifying potential tax effects of our operations and business decisions, could adversely affect our results of operations and liquidity.

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations in order to estimate our obligations to taxing authorities. The obligations, which include income taxes and taxes other than income taxes, involve complex matters that ultimately could be litigated. We also estimate our ability to use tax benefits, including those in the form of carryforwards and tax credits that are recorded as deferred tax assets on our Consolidated Balance Sheet. A disallowance of some or all of these tax benefits could have an adverse impact on our financial position, results of operations and cash flows.

We are currently utilizing, and plan to utilize in the future, our carryforwards and tax credits to reduce our income tax obligations. If we cannot generate enough taxable income in the future to utilize all of our carryforwards and tax credits before they expire, we may incur adverse charges to earnings.

If federal or state tax authorities deny any deductions or tax credits, negatively change existing tax laws or policies, or fail to extend or renew policies beneficial to the Company, such as those for renewable energy production tax credits, our financial position, results of operations and cash flows may be adversely impacted.

Our business, financial position, results of operations, and cash flows could be materially affected by adverse results of litigation.

We are involved in litigation arising in the normal course of business. Unfavorable resolution of legal or administrative proceedings in which we are involved or other future legal or administrative proceedings may have an adverse effect on our business, financial position, results of operations and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

ALLETE employs a multilayer approach to addressing cybersecurity risk based on the National Institute of Standards and Technology (NIST) framework. It has established a dedicated cybersecurity team that utilizes internal and external assessments, automated monitoring tools, and input from public and private partners to identify potential cyber threats. External third party security firms are engaged to assist with cybersecurity risk assessments, penetration testing and system security analysis. ALLETE’s cybersecurity team works in conjunction with the risk management, legal, finance, accounting, operations, and information technology areas to assess the risk these identified cybersecurity threats present to the organization. To ensure consistency, these cybersecurity risk assessments are incorporated into ALLETE’s Enterprise Risk Management process, ALLETE’s information technology leadership reviews the company’s enterprise risk management-level cybersecurity risks on a quarterly basis, and key cybersecurity risks are incorporated into ALLETE’s enterprise risk management framework. Cybersecurity risks are managed and controlled through multiple overlapping layers of cybersecurity defenses that include:

- expert input from both public and private partnerships;
- the implementation of a comprehensive cybersecurity policy that encompasses but is not limited to social media, acceptable use (devices, wireless, remote access, internet use), information governance, monitoring, authentication, encryption, vulnerability management, third-party management, and recovery;
- required annual cybersecurity training for all employees with additional supplemental cybersecurity training required based on role;
- random employee phish testing and follow-up;
- procedural and automated cyber controls in conjunction with robust detection, mitigation, and recovery capabilities;
- the formation of a multidisciplinary cybersecurity incident response team;
- the integration of multiple threat intelligence sources into our cybersecurity tools and processes;
- the retention of external cybersecurity threat response resources;
- the formation of a multidisciplinary cybersecurity incident response team; and
- multiple cyber event simulation and tabletop exercises per year to hone the cybersecurity incident response team preparedness.

The ALLETE board of directors provides enterprise-level oversight of risks associated with cybersecurity threats through the Audit Committee, which assists the Board in fulfilling its oversight responsibilities regarding the Company’s policies and processes with respect to risk assessment and risk management, including any significant non-financial risk exposures; reviewing and discussing the Company’s information security policies and internal controls regarding information security; and reviewing the Company’s annual disclosures concerning the role of the Board in the risk oversight of the Company. The Audit Committee performs an annual review of the Company’s cybersecurity program and receives quarterly updates on key cybersecurity risks, the cybersecurity risk management plan, and cyber incident event trends.

ALLETE’s Chief Technology Officer (CTO) has primary responsibility for the development and oversight of ALLETE’s cybersecurity team and the development and maintenance of the company’s related cybersecurity policies and procedures. The CTO has over 25 years’ experience working in the information and operational technology field and is a registered professional engineer in the State of Minnesota. The company’s cybersecurity team continuously assesses the evolving cyber threat landscape based on their expertise and that of our third-party partners. They then work with all parts of ALLETE to protect against, detect, identify, respond to, and recover from the risks that cybersecurity threats present. The cybersecurity team views and responds to cybersecurity risks in a holistic manner, applying a comprehensive multilayered strategy to prevent, detect, and mitigate them. They have identified ALLETE’s critical cyber assets and taken appropriate steps to protect them. External expertise is regularly engaged to assess ALLETE’s cybersecurity program and help the cybersecurity team to strengthen the organization’s monitoring, alerting, prevention, mitigation, and recovery capabilities. Tabletop simulations, third party cyber vulnerability assessments, maturity assessments, and partnerships are used to assess and refine all elements of our cybersecurity program.

In addition to managing our own cybersecurity preparedness, we also consider and evaluate cybersecurity risks associated with the use of third-party service providers. Risk assessments are performed against third-party service providers with a specific focus on any sensitive data that is to be shared with them. The internal business owners of ALLETE’s applications are required to document user access reviews regularly. We request a System and Organizational Controls (SOC) 2 report from the vendors of our enterprise cloud applications. If they do not provide us with a SOC 2, we seek additional compensating risk assurance in our contract language with them. Risks associated with the use of third-party service providers are managed as part of our overall cybersecurity risk management framework.

Item 1C. Cybersecurity (Continued)

To continually manage and control the material risks that cybersecurity threats present to the organization, ALLETE invests significantly in the cybersecurity elements outlined above. In addition, the Company has made significant investments to fulfill the operational and financial regulatory requirements laid out by the North American Electric Reliability Corporation Critical Infrastructure Protection Standards and Sarbanes-Oxley Act of 2002.

ALLETE faces a number of cybersecurity risks in connection with its business. Although such risks have not materially affected us, including our business strategy, results of operations, and financial conditions, to date, we have, from time to time, experienced threats to and breaches of our data systems, including malware, phishing and computer virus attacks. See Item 1A. Risk Factors for additional information regarding our organization's cybersecurity risks, which should be read together with this Item 1C. Cybersecurity.

Item 2. Properties

A discussion of our properties is included in Item 1. Business and is incorporated by reference herein.

Item 3. Legal Proceedings

Discussions of material regulatory and environmental proceedings are included in Note 4. Regulatory Matters and Note 9. Commitments, Guarantees and Contingencies, and are incorporated by reference herein.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-K.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.705 per share on our common stock is payable on March 1, 2024, to the shareholders of record on February 15, 2024. The timing and amount of future dividends will depend upon earnings, cash requirements, the financial condition of the Company, applicable government regulations and other factors deemed relevant by the ALLETE Board of Directors. As of February 1, 2024, there were approximately 19,000 common stock shareholders of record.

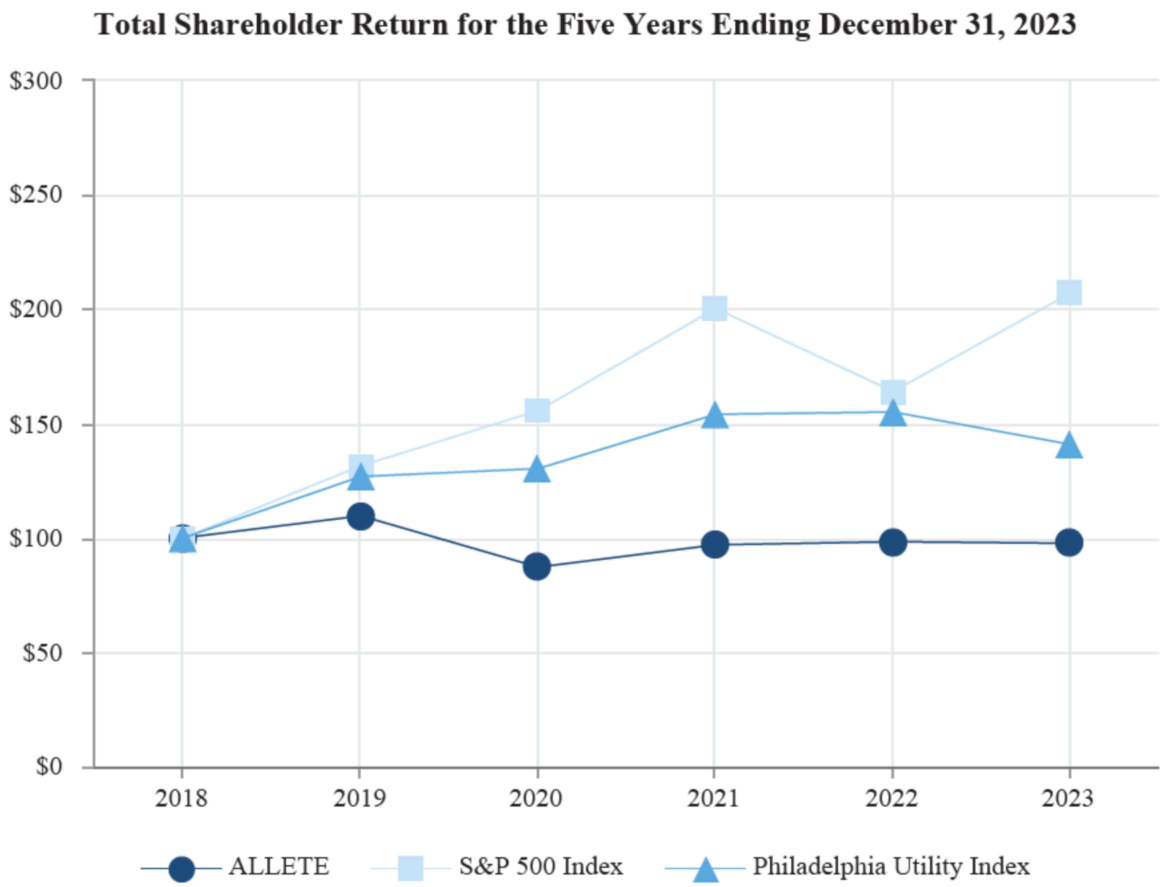
We do not have a publicly announced stock repurchase program and we did not repurchase any equity securities during the quarter ended December 31, 2023.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities (Continued)

Performance Graph.

The following graph compares ALLETE's cumulative Total Shareholder Return on its common stock with the cumulative return of the S&P 500 Index and the Philadelphia Utility Index. The S&P 500 Index is a capitalization-weighted index of 500 stocks designed to measure performance of the broad domestic economy through changes in the aggregate market value of 500 stocks representing all major industries. Because this composite index has a broad industry base, its performance may not closely track that of a composite index comprised solely of electric utilities. The Philadelphia Utility Index is a capitalization-weighted index of 20 utility companies involved in the generation of electricity.

The calculations assume a $100 investment on December 31, 2018, and reinvestment of dividends.



	2018	2019	2020	2021	2022	2023
ALLETE	$100	$110	$87	$97	$98	$98
S&P 500 Index	$100	$131	$156	$200	$164	$207
Philadelphia Utility Index	$100	$127	$130	$154	$155	$141

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our Consolidated Financial Statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-K contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Forward-Looking Statements" located on page 7 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only risks facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the risks are realized.

Overview

Basis of Presentation. We present two reportable segments: Regulated Operations and ALLETE Clean Energy. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 150,000 retail customers. Minnesota Power also has 14 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Note 4. Regulatory Matters.)

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in seven states, more than 1,200 MW of nameplate capacity wind energy generation with a majority contracted under PSAs of various durations. In addition, ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

Corporate and Other is comprised of New Energy, a renewable development company; our investment in Nobles 2, an entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota; South Shore Energy, our non-rate regulated, Wisconsin subsidiary developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility; BNI Energy, our coal mining operations in North Dakota; ALLETE Properties, our legacy Florida real estate investment; other business development and corporate expenditures; unallocated interest expense; a small amount of non-rate base generation; land holdings in Minnesota; and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2023, unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

2023 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2023, to the year ended December 31, 2022.

Net income attributable to ALLETE in 2023 was $247.1 million, or $4.30 per diluted share, compared to $189.3 million, or $3.38 per diluted share, in 2022. Net income in 2023 included a $40.5 million, or $0.71 per share, after-tax gain recognized for a favorable arbitration ruling involving a subsidiary of ALLETE Clean Energy. (See Note 9. Commitments, Guarantees and Contingencies.) This increase was partially offset by the impact of unusually low wind resources at ALLETE Clean Energy and warmer winter weather impacting our Regulated Operations in 2023. Earnings per share dilution in 2023 was $0.11 due to additional shares of common stock outstanding in 2023 compared to 2022.

Regulated Operations net income attributable to ALLETE was $147.2 million in 2023, compared to $149.9 million in 2022. Net income at Minnesota Power was lower than 2022 primarily due to higher operating and maintenance, depreciation and interest expenses, and lower kWh sales to residential and commercial customers in 2023 compared to 2022 due to warmer winter weather. These decreases were partially offset by higher kWh sales to industrial customers in 2023 and lower property tax expense resulting from the favorable impact of an updated estimate for property taxes payable in 2023. Net income at SWL&P was higher than 2022 primarily due to the implementation of new rates from its most recent rate case in 2023. (See Note 4. Regulatory Matters.) Our after-tax equity earnings in ATC were higher than 2022 reflecting period over period changes in ATC's estimate of a refund liability related to the appeals court decision on MISO return on equity complaints in 2022. (See Note 6. Equity Investments.)

ALLETE Clean Energy net income attributable to ALLETE was $71.7 million in 2023 compared to $16.3 million in 2022. Net income in 2023 reflected a $44.3 million after-tax gain recognized for a favorable arbitration ruling involving a subsidiary of ALLETE Clean Energy. Net income in 2023 also included the gain on sale of the Red Barn project in 2023 of $4.3 million after-tax and higher interest income related to interest awarded as part of the arbitration ruling. These increases were partially offset by lower wind resources and availability at its wind energy facilities in 2023 as well as a network outage located near its Caddo wind energy facility resulting in lower earnings. Net income in 2022 included reserves for an anticipated loss on the sale of ALLETE Clean Energy's project to repower and sell its Northern Wind project as well as earnings from the legacy Northern Wind facilities, which were decommissioned in April 2022 as part of the project.

Corporate and Other net income attributable to ALLETE was $28.2 million in 2023 compared to $23.1 million in 2022. Net income in 2023 reflects higher earnings from New Energy in 2023 compared to 2022 as a result of more renewable development projects closing during 2023, income in 2023 from net losses attributable to non-controlling interest for tax equity financed solar energy facilities and the impact of purchase price accounting in 2022. Net income from New Energy in 2023 was $17.6 million. Net income from New Energy in 2022 was $7.8 million, which included a $8.3 million after-tax expense as a result of purchase price accounting related to projects under development at the time of acquisition. Net income in 2023 also reflects earnings from Minnesota solar projects placed into service in the fourth quarter of 2022 and second quarter of 2023, and a $3.8 million after-tax expense for the consolidated income tax impact resulting from the gain on the favorable arbitration ruling. Net income in 2022 included transaction costs of $2.7 million after-tax related to the acquisition of New Energy in April 2022.

2023 Compared to 2022

(See Note 14. Business Segments for financial results by segment.)

Regulated Operations

Year Ended December 31	2023	2022
Millions		
Operating Revenue – Utility	$1,238.3	$1,259.3
Fuel, Purchased Power and Gas – Utility	484.3	545.5
Transmission Services – Utility	88.2	76.7
Operating and Maintenance	247.1	239.3
Depreciation and Amortization	179.2	171.9
Taxes Other than Income Taxes	44.5	57.4
Operating Income	195.0	168.5
Interest Expense	(63.9)	(58.1)
Equity Earnings	23.1	19.3
Other Income	15.4	9.8
Income Before Income Taxes	169.6	139.5
Income Tax Expense (Benefit)	22.4	(10.4)
Net Income Attributable to ALLETE	$147.2	$149.9

Operating Revenue – Utility decreased $21.0 million from 2022 primarily due to lower kWh sales, fuel adjustment clause recoveries and gas sales, partially offset by higher cost recovery rider revenue, FERC formula-based rates and transmission revenue.

Lower kWh sales reduced revenue $32.5 million from 2022 reflecting lower sales to residential, commercial and municipal customers as well as lower sales to other power suppliers, partially offset by higher sales to industrial customers. Sales to residential, commercial and municipal customers decreased from 2022 primarily due to warmer weather in the winter months in 2023 compared to 2022. Heating degree days for Duluth, Minnesota, were down 13 percent in 2023 compared to 2022. Sales to municipal customers also decreased as a result of a new contract entered into with Hibbing Public Utilities in 2022 with sales under the new contract now classified under other power suppliers. Sales to industrial customers increased primarily due to higher sales to taconite customers as well as sales to ST Paper, which became a Large Power Customer in 2023, higher sales to Cenovus Energy, which restarted its refinery in Superior, Wisconsin, in 2023, and higher sales to pipeline and other customers. (See *Outlook – Regulated Operations – Industrial Customers – ST Paper and Cenovus Energy*.) Sales to other power suppliers, which are sold at market-based prices into the MISO market on a daily basis or through PSAs of various durations, decreased in 2023 compared to 2022 primarily due to fewer market sales and lower market prices in 2023 compared to 2022.

Kilowatt-hours Sold	2023	2022	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	1,089	1,148	(59)	(5.1)
Commercial	1,347	1,359	(12)	(0.9)
Industrial	7,044	6,745	299	4.4
Municipal	466	540	(74)	(13.7)
Total Retail and Municipal	9,946	9,792	154	1.6
Other Power Suppliers	2,819	3,149	(330)	(10.5)
Total Regulated Utility Kilowatt-hours Sold	12,765	12,941	(176)	(1.4)

Revenue from electric sales to taconite and mining customers accounted for 32 percent of regulated operating revenue in 2023 (32 percent in 2022). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of regulated operating revenue in 2023 (5 percent in 2022). Revenue from electric sales to pipelines and other industrial customers accounted for 11 percent of regulated operating revenue in 2023 (10 percent in 2022).

Fuel adjustment clause revenue decreased $20.6 million primarily due to lower fuel and purchased power costs attributable to retail and municipal customers. (See *Fuel, Purchased Power and Gas – Utility*.)

Revenue from gas sales at SWL&P decreased $4.6 million reflecting fewer gas sales resulting from warmer winter weather and lower gas prices in 2023 compared to 2022. (See *Fuel, Purchased Power and Gas – Utility*.)

Cost recovery rider revenue increased $18.2 million primarily due to fewer production tax credits generated by Minnesota Power. If production tax credits are generated at a level below those assumed in Minnesota Power's retail rates, an increase in cost recovery rider revenue is recognized to offset the impact of lower production tax credits on income tax expense.

Revenue from wholesale customers under FERC formula-based rates increased $9.6 million primarily due to higher rates reflecting higher expenses billable under wholesale customer contracts.

Transmission revenue increased $9.2 million primarily due to higher MISO-related revenue.

Operating Expenses decreased $47.5 million from 2022.

Fuel, Purchased Power and Gas – Utility expense decreased $61.2 million, or 11 percent, from 2022 primarily due to lower kWh sales, purchased power prices and fuel costs as well as lower gas sales and prices.

Transmission Services – Utility expense increased $11.5 million, or 15 percent, from 2022 primarily due to higher MISO-related expense.

Operating and Maintenance expense increased $7.8 million, or 3 percent, from 2022 primarily due to higher salaries and wages, vegetation management costs, and materials purchased for use in generation facilities and field operations. These increases were partially offset by lower contract and professional services as well as lower benefit costs.

Depreciation and Amortization expense increased $7.3 million, or 4 percent, from 2022 primarily due to a higher plant in service balance in 2023.

Taxes Other than Income Taxes decreased $12.9 million, or 22 percent, from 2022 primarily due to lower property tax expense resulting from the favorable impact of an updated estimate for 2022 property tax expense recorded in 2023.

Interest Expense increased $5.8 million, or 10 percent, from 2022 primarily due to higher interest rates and interest on Minnesota Power's reserve for interim rate refunds in 2023.

Equity Earnings increased $3.8 million from, or 20 percent, 2022 primarily due to period over period changes in ATC's estimate of a refund liability related to the appeals court decision on MISO return on equity complaints in 2022. (See Note 6. Equity Investments.)

Other Income increased $5.6 million from 2022 reflecting year over year differences in various individually immaterial items.

Income Tax Expense increased $32.8 million from 2022. The effective tax rate in 2023 was an income tax expense compared to a benefit in 2022 primarily due to lower production tax credits and higher pre-tax income.

2023 Compared to 2022 (Continued)
ALLETE Clean Energy

Year Ended December 31	2023	2022
Millions		
Operating Revenue		
Contracts with Customers – Non-utility	$413.4	$110.7
Other – Non-utility *(a)*	5.1	7.6
Cost of Sales – Non-utility	342.2	56.7
Operating and Maintenance	52.1	47.3
Depreciation and Amortization	57.5	58.6
Taxes Other than Income Taxes	10.0	10.7
Operating Loss	(43.3)	(55.0)
Interest Expense	(0.8)	(2.3)
Other Income *(b)*	68.0	10.8
Income (Loss) Before Income Taxes	23.9	(46.5)
Income Tax Expense (Benefit)	2.7	(15.4)
Net Income (Loss)	21.2	(31.1)
Net Loss Attributable to Non-Controlling Interest *(b)*	(50.5)	(47.4)
Net Income Attributable to ALLETE	$71.7	$16.3

(a) Represents non-cash amortization of differences between contract prices and estimated market prices on assumed PSAs.
(b) See Note 1. Operations and Significant Accounting Policies.

Operating Revenue increased $300.2 million from 2022 primarily due to the sales of ALLETE Clean Energy's Northern Wind and Red Barn projects in 2023. This increase was partially offset by lower wind resources and availability at wind energy facilities in all regions in 2023 compared to 2022. Wind availability was down across the nation much of the year and, consequently, ALLETE Clean Energy revenue was negatively impacted in 2023. Operating revenue in 2023 was also negatively impacted by a forced outage in the fourth quarter of 2023 to a substation and the transmission lines feeding that substation located near ALLETE Clean Energy's Caddo wind energy facility. This forced outage increased congestion experienced by the Caddo wind energy facility resulting in lower kWh sales and pricing. In 2022, operating revenue also included revenue from the legacy Northern Wind facilities, which were decommissioned in April 2022 as part of ALLETE Clean Energy's Northern Wind project.

	Year Ended December 31,			
	2023		2022	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Regions				
East	224.0	$21.2	266.6	$24.3
Midwest *(a)*	560.9	18.4	775.9	27.0
South	1,720.8	16.8	2,047.1	15.4
West	714.1	13.6	829.5	18.1
Total Wind Energy Facilities	3,219.8	70.0	3,919.1	84.8
Sale of Wind Energy Facility	—	348.5	—	33.5
Total Production and Operating Revenue	3,219.8	$418.5	3,919.1	$118.3

(a) The Chanarambie and Viking wind energy facilities were decommissioned in the second quarter of 2022 as part of ALLETE Clean Energy's Northern Wind project.

2023 Compared to 2022 (Continued)
ALLETE Clean Energy (Continued)

Cost of Sales - Non-utility increased $285.5 million from 2022 reflecting the sales of ALLETE Clean Energy's Northern Wind and Red Barn projects in 2023. Cost of Sales – Non-utility in 2022 reflected reserves in 2022 related to ALLETE Clean Energy's project to repower and sell its Northern Wind project resulting from inflationary increases and significant cost pressures. In addition, 2022 included a $10.2 million reserve in the second quarter related to the sale of the Northern Wind project, which was fully offset by a gain on removal of the PSA liability for the Northern Wind project upon decommissioning of the wind energy facilities. (See *Other Income*.)

Operating and Maintenance expense increased $4.8 million, or 10 percent, from 2022 primarily due to higher contract and professional services in 2023. Arbitration-related costs incurred in 2023 for arbitration proceedings involving a subsidiary of ALLETE Clean Energy were fully offset by the recovery of $3.6 million for arbitration-related costs that were awarded as part of a favorable arbitration ruling. (See Note 9. Commitments, Guarantees and Contingencies.)

Other Income increased $57.2 million from 2022 primarily due to a $58.4 million gain recognized for a favorable arbitration ruling involving a subsidiary of ALLETE Clean Energy and higher interest income related to $5.1 million of interest awarded as part of the favorable arbitration ruling. (See Note 9. Commitments, Guarantees and Contingencies.) Other Income in 2022 reflected a gain on removal of the PSA liability for the Northern Wind project upon decommissioning of the wind energy facilities in 2022. (See *Cost of Sales – Non-utility*.)

Income Tax Expense increased $18.1 million from 2022 primarily due to higher pre-tax income in 2023 compared to 2022.

Net Loss Attributable to Non-Controlling Interest increased $3.1 million from 2022 reflecting a higher production tax credit rate, as determined by the Internal Revenue Service, in 2023 compared to 2022. This increase was partially offset by lower wind resources at our tax equity financed wind energy facilities.

Corporate and Other

Operating Revenue increased $29.9 million, or 15 percent, from 2022 reflecting higher revenue from New Energy, which was acquired in April 2022, and higher revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of higher expenses in 2023 compared to 2022.

Net Income Attributable to ALLETE was $28.2 million in 2023 compared to $23.1 million in 2022. Net income in 2023 reflects higher earnings from New Energy in 2023 compared to 2022 as a result of more renewable development projects closing during 2023, income in 2023 from net losses attributable to non-controlling interest for tax equity financed solar energy facilities and the impact of purchase price accounting in 2022. Net income from New Energy in 2023 was $17.6 million. Net income from New Energy in 2022 was $7.8 million, which included a $8.3 million after-tax expense as a result of purchase price accounting related to projects under development at the time of acquisition. Net income in 2023 also reflects earnings from Minnesota solar projects placed into service in the fourth quarter of 2022 and second quarter of 2023, and a $3.8 million after-tax expense for the consolidated income tax impact resulting from the gain on the favorable arbitration ruling. Net income in 2022 included transaction costs of $2.7 million after-tax related to the acquisition of New Energy in April 2022.

Income Taxes – Consolidated

For the year ended December 31, 2023, the effective tax rate was an expense of 13.5 percent (benefit of 31.2 percent for the year ended December 31, 2022). The effective tax rate for 2023 an expense compared to a benefit in 2022 primarily due to higher pre-tax income and lower production tax credits. (See Note 11. Income Tax Expense.)

2022 Compared to 2021

The comparison of the results of operations for the years ended December 31, 2022 and 2021 is included in Management's Discussion in the Annual Report on Form 10-K for the year ended December 31, 2022.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the Consolidated Financial Statements. These estimates and assumptions may be revised, which may have a material effect on the Consolidated Financial Statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. We believe the following policies are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are subject to accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. This assessment considers factors such as, but not limited to, changes in the regulatory environment and recent rate orders to other regulated entities under the same jurisdiction. If future recovery or refund of costs becomes no longer probable, the assets and liabilities would be recognized in current period net income or other comprehensive income. (See Note 4. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and other postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of several important assumptions, including the expected long-term rate of return on plan assets, the discount rate and mortality assumptions, among others, in determining our obligations and the annual cost of our pension and other postretirement benefits. In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class and adjust these for current economic conditions while utilizing the target allocation of our plan assets to forecast the expected long-term rate of return. Our pension asset allocation as of December 31, 2023, was approximately 57 percent equity securities, 40 percent fixed income and 3 percent real estate. Our postretirement health and life asset allocation as of December 31, 2023, was approximately 67 percent equity securities, and 33 percent fixed income. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. In 2023, we used weighted average expected long-term rates of return of 6.83 percent in our actuarial determination of our pension expense and 6.33 percent in our actuarial determination of our other postretirement expense. The actuarial determination uses an asset smoothing methodology for actual returns to reduce the volatility of varying investment performance over time. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $2.1 million, pre-tax.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans. In 2023, we used weighted average discount rates of 5.70 percent and 5.89 percent in our actuarial determination of our pension and other postretirement expense, respectively. We review our discount rates annually and will adjust them to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $0.4 million, pre-tax.

The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2023, considered a modified PRI-2012 mortality table and MP-2021 mortality projection scale. (See Note 12. Pension and Other Postretirement Benefit Plans.)

Valuation of Business Combinations and Resulting Goodwill. When we acquire a business, the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. Determining the fair value of intangible assets acquired as part of a business combination requires us to make significant estimates. These estimates may include the amount and timing of projected future cash flows, the discount rate used to discount those cash flows to present value, the assessment of the asset’s life cycle, and the consideration of legal, technical, regulatory, economic and competitive risks.

Critical Accounting Policies (Continued)

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of the net assets of the acquired businesses. In accordance with GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit's net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. Our estimates associated with the goodwill impairment test are considered critical due to the amount of goodwill recorded on our Consolidated Balance Sheet and the judgment required in determining fair value. The fair value of the New Energy reporting unit was determined using a discounted cash flow model, using significant assumptions which included a discount rate of 14 percent, cash flow forecasts through 2028, industry average gross margins, and a terminal growth rate of 3.5 percent. Any forecast contains a degree of uncertainty, and changes in the forecasted cash flows and other assumptions could significantly increase or decrease the calculated fair value of New Energy. The results of our annual impairment test are discussed in Note 1. Operations and Significant Accounting Policies and Note 7. Fair Value in this Form 10-K. Goodwill was $154.9 million as of December 31, 2023.

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our long-lived assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations. (See Note 1. Operations and Significant Accounting Policies.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income taxes and taxes other than income taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized.

We are subject to income taxes in various jurisdictions. We make assumptions and judgments each reporting period to estimate our income tax assets, liabilities, benefits and expenses. Judgments and assumptions are supported by historical data and reasonable projections. Our assumptions and judgments include the application of tax statutes and regulations, and projections of future federal taxable income, state taxable income, and state apportionment to determine our ability to utilize NOL and credit carryforwards prior to their expiration. Significant changes in assumptions regarding future federal and state taxable income or a change in tax rates could require new or increased valuation allowances which could result in a material impact on our results of operations.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses, and sustains growth. The Company has a long-term objective of achieving consolidated earnings per share growth within a range of 5 percent to 7 percent.

ALLETE is predominately a regulated utility through Minnesota Power, SWL&P, and an investment in ATC. ALLETE's strategy is to remain predominately a regulated utility while investing in ALLETE Clean Energy, New Energy and its Corporate and Other businesses to complement its regulated businesses, balance exposure to the utility's industrial customers, and provide potential long-term earnings growth. ALLETE expects net income from Regulated Operations to be approximately 75 percent of total consolidated net income in 2024. ALLETE expects its businesses to generally provide regulated, contracted or recurring revenues, and to support sustained growth in net income and cash flow.

In August 2022, the Inflation Reduction Act was signed into law. We believe our businesses will benefit from certain provisions of the legislation including from the extension and transferability of production tax credits and investment tax credits, among others. We are planning to sell certain tax credits generated in 2023 and beyond. We do not currently anticipate any impact from the new alternative minimum tax. We will continue to assess the impact of the law as additional implementation guidance becomes available.

Minnesota Carbon-Free Legislation. On February 7, 2023, the Minnesota Governor signed into law legislation that updates the state's renewable energy standard and requires Minnesota electric utilities to source retail sales with 100 percent carbon-free energy by 2040. The law increases the renewable energy standard from 25 percent renewable by 2025 to 55 percent renewable by 2035, and requires investor-owned Minnesota utilities to provide 80 percent carbon-free energy by 2030, 90 percent carbon-free energy by 2035 and 100 percent carbon-free energy by 2040. The law utilizes renewable energy credits as the means to demonstrate compliance with both the carbon-free and renewable standards, includes an off-ramp provision that enables the MPUC to protect reliability and customer costs through modification or delay of either the renewable energy standard, the carbon-free standard, or both, and streamlines development and construction of wind energy projects and transmission in Minnesota. The Company is evaluating the law to identify challenges and opportunities it could present.

Regulated Operations. Minnesota Power's long-term strategy is to be the leading electric energy provider in northeastern Minnesota by providing safe, reliable and cost-competitive electric energy, while complying with environmental permit conditions and renewable energy requirements. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain customer viability. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. Minnesota Power has a vision of delivering 100 percent carbon-free energy by 2050. (See *EnergyForward*.) We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approvals for transmission, renewable and environmental investments, as well as work with regulators to earn a fair rate of return.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, FERC, PSCW and NDPSC. See Note 4. Regulatory Matters for discussion of regulatory matters within these jurisdictions.

2024 Minnesota General Rate Case. On November 1, 2023, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 12.00 percent for retail customers, net of rider revenue incorporated into base rates. The rate filing seeks a return on equity of 10.30 percent and a 53.00 percent equity ratio. On an annualized basis, the requested final rate increase would generate approximately $89 million in additional revenue. In orders dated December 19, 2023, the MPUC accepted the filing as complete and approved an annual interim rate increase of approximately $64 million, net of rider revenue, beginning January 1, 2024, subject to refund. We cannot predict the level of final rates that may be authorized by the MPUC.

Wisconsin Retail Rates. SWL&P expects to file its next general rate case with the PSCW in the first quarter of 2024.

Outlook (Continued)

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper, pulp and secondary wood products, pipeline and other industries. Approximately 55 percent of our regulated utility kWh sales in 2023 (52 percent in 2022 and 47 percent in 2021) were made to our industrial customers. We expect industrial sales of approximately 7.0 million MWh in 2024 (7.0 million MWh in 2023 and 6.7 million in 2022). (See Item 1. Business – Regulated Operations – Electric Sales / Customers.)

Taconite. Minnesota Power's taconite customers are capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry, which continue to lead the world in environmental performance among steelmaking countries. According to the U.S. Department of Energy, steel production in the U.S. is the most energy efficient of any major steel producing country. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, tubular applications for all industries, and in the construction industry. Steel is also a critical component of the clean energy transformation underway today. Meeting the demand for more renewable energy and the need for additional infrastructure to transport green energy from the point of generation to the end user both require steel. Historically, approximately 10 percent of Minnesota taconite production has been exported outside of North America.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 75 percent of capacity in 2023 (78 percent in 2022 and 82 percent in 2021). The World Steel Association, an association of steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2024 will increase by approximately 2 percent compared to 2023.

Minnesota Power's taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. The Minnesota Department of Revenue Mineral Tax Office expects taconite production from our taconite customers to be approximately 35 million tons in 2024. We estimate that a one million ton change in Minnesota Power's taconite customers' production would impact our annual earnings per share by approximately $0.05, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

USS Corporation. USS Corporation has announced plans to invest approximately $150 million to construct a system dedicated to producing direct reduced-grade (DR-grade) pellets at its Keetac plant. USS Corporation broke ground on the project in the third quarter of 2022, and is expected to begin producing DR-grade pellets in 2024. This will enable the existing pelletizing plant to not only create DR-grade pellets for use as a feedstock for a direct reduced iron (DRI) or hot briquetted iron (HBI) process that ultimately supplies electric arc furnace steelmaking but also maintains the optionality to continue producing blast furnace-grade pellets. USS Corporation's Minntac and Keetac plants are Large Power industrial customers of Minnesota Power. USS Corporation has the capability to produce approximately 15 million and 5 million tons annually at its Minntac and Keetac plants, respectively.

In the third quarter of 2023, USS Corporation disclosed it had commenced a formal review process to evaluate strategic alternatives for the company after receiving multiple unsolicited proposals that ranged from the acquisition of certain production assets to consideration for the whole company. On December 18, 2023, USS Corporation announced it entered into a definitive agreement in which Nippon Steel will acquire all of the shares of USS Corporation. USS Corporation expects the transaction to close in the second or third quarter of 2024, subject to regulatory approvals, at which time USS Corporation stated it will continue to operate under the U.S. Steel brand name and will maintain its headquarters in Pittsburgh, Pennsylvania.

Cleveland-Cliffs, Inc. (Cliffs). In 2020, Cliffs announced that it had completed the previously announced acquisition of substantially all of the operations of ArcelorMittal USA LLC and its subsidiaries. Cliffs had stated that upon closure of the acquisition, Cliffs would be the largest flat-rolled steel producer and the largest iron ore pellet producer in North America. The acquisition included ArcelorMittal's Minorca mine in Virginia, Minnesota, and its ownership share of Hibbing Taconite in Hibbing, Minnesota, which are both large industrial customers of Minnesota Power. Cliffs is Minnesota Power's largest customer. The acquisition has increased customer concentration risk for the Company and could lead to further capacity consolidation for both steel blast furnaces and related Minnesota iron ore production.

Outlook (Continued)
Industrial Customers (Continued)

Cliffs completed construction of a hot briquetted iron production plant in Toledo, Ohio, in 2020, which has utilized direct reduced-grade pellets from Northshore Mining. In October 2021, Cliffs indicated it plans to move direct reduced-grade pellet production to its Minorca mine and that Northshore Mining would become a "swing facility" due to the higher royalty rates at that mine. (See *Northshore Mining*.)

Northshore Mining. Cliffs idled all production at its Northshore mine in 2022. Northshore Mining resumed partial pellet plant production in April 2023. Cliffs indicated it will continue to utilize Northshore Mining as a swing facility. Northshore Mining has the capability to produce approximately 6 million tons annually. Minnesota Power has a PSA through 2031 with Silver Bay Power, which provides the majority of the electric service requirements for Northshore Mining.

Hibbing Taconite. Hibbing Taconite is a joint venture between subsidiaries of Cliffs (85.3 percent ownership) and USS Corporation (14.7 percent ownership). The joint venture is managed by Cliffs and is also a Large Power Customer of Minnesota Power. On May 25, 2023, the Minnesota Executive Council approved state mineral leases near Nashwauk, Minnesota, with Cliffs, the majority owner of Hibbing Taconite. Cliffs has stated that these leases will provide Hibbing Taconite with more than two decades of additional mineral reserves. Prior to the leases being awarded, Hibbing Taconite had proven mineral reserves to support its operations through 2026. Hibbing Taconite has the capability of producing 8 million tons of taconite annually.

Minnesota Sulfate Wild Rice Water Quality Standard. On April 29, 2021, the EPA identified rivers and lakes in Minnesota in which wild rice grows that have sulfate levels that exceed Minnesota's sulfate limit for wild rice waters. On September 1, 2021, three additional wild rice waters with sulfate levels that exceed Minnesota's sulfate limit were identified. The EPA directed the MPCA to add these rivers and lakes to its list of impaired waters which can be used to set limits in discharge permits for industrial activities such as mining. Minnesota Power's taconite customers could be adversely impacted if they are required to significantly reduce sulfate discharges.

Paper, Pulp and Secondary Wood Products. The North American paper and pulp industry continues to face declining demand due to the impact of electronic substitution for print and changing customer needs. As a result, certain paper and pulp customers have reduced their existing operations in recent years and have pursued or are pursuing product changes in response to the declining demand. The resulting reduction in production capacity outside of Minnesota for certain paper grades has solidified our paper customers' operations, at least for the near term, and as such we expect operating levels in 2024 at the major paper and pulp mills we serve to be at similar levels as in 2023.

ST Paper. In May 2021, ST Paper announced it had completed the purchase of the Duluth Mill from Verso Corporation. In January 2022, Minnesota Power entered into an electric service agreement with ST Paper that would begin Large Power Customer service with a minimum term of six years upon start-up of operations. ST Paper completed start-up of operations and became a Large Power Customer as of the first quarter of 2023. On January 3, 2024, ST Paper announced it had entered into an asset purchase agreement to sell the Duluth Mill to Sofidel, a privately held Italian multinational company that is currently the seventh largest manufacturer of tissue paper in the world.

Pipeline and Other Industries.

Cenovus Energy. In 2018, a fire at Cenovus Energy's refinery in Superior, Wisconsin, which was owned by Husky Energy at that time, disrupted operations at the facility. Under normal operating conditions, SWL&P provides approximately 14 MW of average monthly demand to the refinery in addition to water service. In April 2023, Cenovus Energy announced that it had commenced restart of the facility.

Outlook (Continued)

EnergyForward. Minnesota Power is executing *EnergyForward*, its strategy assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind, solar, natural gas and hydroelectric power, construction of additional transmission capacity, the installation of emissions control technology and the idling and retirement of certain coal-fired generating facilities. Minnesota Power has a vision to deliver 100 percent carbon-free energy to customers, continuing its commitment to climate, customers and communities through its *EnergyForward* strategy. This vision builds on Minnesota Power's recent achievement of now providing 50 percent renewable energy to its customers. In 2023, the Minnesota Governor signed into law legislation that updates the state's renewable energy standard and requires Minnesota electric utilities to source retail sales with 100 percent carbon-free energy by 2040. Minnesota Power is working with various stakeholders and participating in the regulatory process to implement this legislation. (See Item 1. Business – Regulated Operations – Minnesota Legislation.)

2021 Integrated Resource Plan (IRP). On February 1, 2021, Minnesota Power filed its latest IRP, which was approved by the MPUC in an order dated January 9, 2023. The approved IRP, which reflects a joint agreement reached with various stakeholders, outlines Minnesota Power's clean-energy transition plans through 2035. These plans include expanding its renewable energy supply, achieving coal-free operations at its facilities by 2035, and investing in a resilient and flexible transmission and distribution grid. As part of these plans, Minnesota Power anticipates adding up to 700 MW of new wind and solar energy resources, and ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Minnesota Power's plans recognize that advances in technology will play a significant role in completing its transition to carbon-free energy supply, reliably and affordably. Minnesota Power is expected to file its next IRP by March 1, 2025.

In recent years, Minnesota Power has transformed its energy supply from more than a 95 percent reliance on coal to become a leader in the nation's clean-energy transformation. Since 2013, the company has closed or converted seven of its nine coal-fired units and added nearly 900 megawatts of renewable energy sources. Additionally, Minnesota Power has been a leader in energy conservation, surpassing the state's conservation goals each year for the past decade.

Nemadji Trail Energy Center (NTEC). In 2017, Minnesota Power submitted a resource package to the MPUC which included requesting approval of a natural gas capacity dedication and other affiliated interest agreements for NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy, ALLETE's non-rate regulated, Wisconsin subsidiary. Minnesota Power is expected to purchase approximately 20 percent of the facility's output starting in 2028 pursuant to the capacity dedication agreement.

Renewable Energy. Minnesota Power continues to execute its renewable energy strategy and reached its goal of supplying 50 percent of its energy by renewable energy sources. Minnesota Power also has a vision of delivering 100 percent carbon-free energy by 2050. (See *EnergyForward*.)

Minnesota Power has approved cost recovery riders for certain renewable investments and expenditures as well as investments and expenditures related to compliance with the Minnesota Solar Energy Standard. The cost recovery riders allow Minnesota Power to charge retail customers on a current basis for the costs of certain renewable and solar investments and expenditures plus a return on the capital invested. (See Note 4. Regulatory Matters.)

Wind Energy. Minnesota Power's wind energy facilities consist of Bison (497 MW) located in North Dakota, and Taconite Ridge (25 MW) located in northeastern Minnesota. Minnesota Power also has two long-term wind energy PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) located in North Dakota.

Minnesota Power uses the 465-mile, 250-kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota, to transport wind energy from North Dakota while gradually phasing out coal-based electricity delivered to its system over this transmission line from Square Butte's lignite coal-fired generating unit. Minnesota Power is currently pursuing a modernization and capacity upgrade of its DC transmission system to continue providing reliable operations and additional system capabilities. (See *Transmission*.)

Wind Energy Request For Proposals. On December 15, 2023, Minnesota Power issued a notice with the MPUC of its intent to issue a request for proposals for up to 400 MW of wind energy resources. Minnesota Power issued the request for proposals on February 15, 2024.

Nobles 2 PPA. Minnesota Power has a long-term PPA with Nobles 2 that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwestern Minnesota through 2040. The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered. (See *Corporate and Other – Investment in Nobles 2*.)

Manitoba Hydro. Minnesota Power has two long-term PPAs with Manitoba Hydro. The first PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro through May 2035. The second PPA provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro through June 2040. (See Note 9. Commitments, Guarantees and Contingencies.)

Solar Energy. Minnesota Power's solar energy facilities consist of a 10 MW solar energy facility at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, and a 40 kW solar array located in Duluth, Minnesota. Minnesota Power also purchases solar energy from approximately 20 MW of solar energy facilities located in Minnesota that are owned by an ALLETE subsidiary, and a 1 MW community solar garden in northeastern Minnesota, which is owned and operated by a third party. SWL&P owns and operates a 470 kW solar array as part of a community solar garden in Superior, Wisconsin, that went into service in 2023.

Solar Energy Request For Proposals. On October 2, 2023, Minnesota Power issued a notice with the MPUC of its intent to issue a request for proposals for up to 300 MW of solar energy resources. Minnesota Power issued the request for proposals on November 15, 2023, which were accepted through January 17, 2024.

***Transmission*.** We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include investments to enhance our own transmission facilities and investments in other transmission assets (individually or in combination with others) and our investment in ATC. See also Item 1. Business – Regulated Operations – Transmission and Distribution.

North Plains Connector Development Agreement. In December 2023, ALLETE and Grid United LLC, an independent transmission company, signed development agreements for the North Plains Connector project. The project is a new, approximately 400-mile high-voltage direct-current (HVDC) transmission line from central North Dakota, to Colstrip, Montana that will be the first transmission connection between three regional U.S. electric energy markets: MISO, the Western Interconnection and the Southwest Power Pool. This new link, open to all sources of electric generation, would create 3,000 MW of transfer capacity between the middle of the country and the West Coast, easing congestion on the transmission system, increasing resiliency and reliability in all three energy markets, and enabling fast sharing of renewable energy across a vast area with diverse weather patterns. The project capital cost is expected to be approximately $3.2 billion. ALLETE expects to pursue up to 35 percent ownership and would oversee the line's operation. The companies began project permitting in 2023 as they work toward a planned in-service date as early as 2029, pending regulatory and other necessary approvals.

Duluth Loop Reliability Project. In October 2021, Minnesota Power submitted an application for a certificate of need for the Duluth Loop Reliability Project. This transmission project was proposed to enhance reliability in and around Duluth, Minnesota. The project includes the construction of a new 115-kV transmission line; construction of an approximately one-mile extension of an existing 230-kV transmission line; and upgrades to several substations. A certificate of need was granted and a route permit was issued by the MPUC on April 3, 2023. The Duluth Loop Reliability Project is expected to be completed and in service by 2025, subject to MPUC approval, with an estimated cost of $50 million to $70 million.

HVDC Transmission System Project. On June 1, 2023, Minnesota Power submitted an application for a certificate of need and route permit with the MPUC to replace aging critical infrastructure and modernize the terminal stations of its HVDC transmission line. Minnesota Power uses the 465-mile, 250-kV HVDC transmission line that runs from Center, North Dakota, to Duluth, Minnesota, to transport wind energy from North Dakota while gradually phasing out coal-based electricity delivered to its system over this transmission line from Square Butte's lignite coal-fired generating unit. The HVDC transmission system project is expected to improve reliability of the transmission system, improve system resiliency, expand the operating capacity of the HVDC terminals, and replace critical infrastructure. Pending regulatory approvals in Minnesota and North Dakota, construction could begin as early as 2024, with an in-service date expected between 2028 and 2030. The project is estimated to cost between $800 million and $900 million. On October 18, 2023, the U.S. Department of Energy awarded a $50 million grant to Minnesota Power for this project, which will be used to prepare the HVDC transmission system for future expansion and help reduce project costs to customers, subject to final application and review process. In addition, this project received $15 million in state funding as part of an energy and climate budget bill passed by the Minnesota Legislature in 2023.

Outlook (Continued)
Transmission (Continued)

Northland Reliability Project. Minnesota Power and Great River Energy announced in July 2022 their intent to build a 180-mile, 345-kV transmission line, connecting northern Minnesota to central Minnesota to support continued reliability in the Upper Midwest. Great River Energy, a wholesale electric power cooperative, and Minnesota Power filed a Notice of Intent to Construct, Own and Maintain the transmission line with the MPUC in August 2022. This joint project is part of a portfolio of transmission projects approved in July 2022 by MISO as part of the first phase of its Long Range Transmission Plan. Planning for the approximately $970 million to $1,350 million transmission line is in its early stages with the route anticipated to generally follow existing rights of way in an established power line corridor. The MPUC will determine the final route as well as cost recovery for Minnesota Power's approximately 50 percent estimated share of the project. On August 4, 2023, Minnesota Power and Great River Energy submitted an application for a certificate of need and route permit with the MPUC. Subject to regulatory approvals, the transmission line is expected to be in service in 2030.

Big Stone South Transmission Project. Northern States Power, Great River Energy, Minnesota Power, Otter Tail Power Company, and Missouri River Energy Resources (Project Developers) announced in July 2022 their intent to build a 150-mile, 345-kV transmission line to improve reliability in North Dakota and South Dakota, and western and central Minnesota. This joint project is part of a portfolio of transmission projects approved in July 2022 by MISO as part of the first phase of its Long Range Transmission Plan. A Notice of Intent to Construct, Own and Maintain the transmission line was filed with the MPUC in October 2022. On September 29, 2023, the Project Developers submitted an application for a certificate of need and route permit with the MPUC. The project is in its early stages and is expected to cost between $600 million and $700 million. The MPUC will determine the final route for the Minnesota portion as well as cost recovery for Minnesota Power's approximately $20 million estimated share of the project. Subject to regulatory approvals, the transmission line is expected to be in service in 2027.

Investment in ATC. ATC's most recent 10-year transmission assessment, which covers the years 2023 through 2032, identifies a need for between $6.6 billion and $8.1 billion in transmission system investments. These investments by ATC, if undertaken, are expected to be funded through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC.

ALLETE Clean Energy

ALLETE Clean Energy will pursue growth through acquisitions or project development. ALLETE Clean Energy is targeting acquisitions of existing operating portfolios which have a mix of long-term PSAs in place and/or available for repowering and recontracting. Further, ALLETE Clean Energy will evaluate actions that will lead to the addition of complimentary clean energy products and services. At this time, ALLETE Clean Energy is focused on actions that will optimize its clean energy project portfolio of operating and development projects, which may include recontracting, repowering, entering into partnerships and divestitures along with continued acquisitions or development of new projects including wind, solar, energy storage or storage ready facilities across North America.

Portions of our ALLETE Clean Energy business are experiencing return pressures that are impacting our earnings per share growth from increased competition, congestion and lower forward price curves, as a growing amount of investment capital is being directed into wind generation opportunities. In addition, current and potential new project developments can be negatively affected by a lower ALLETE stock price, which may result in such projects not being accretive, or otherwise unable to satisfy our financial objectives criteria to proceed. In response to these market pressures, we are actively evaluating additional growth opportunities to deliver more comprehensive clean energy solutions for customers at ALLETE Clean Energy, which may include wind, solar, storage solutions, and related energy infrastructure investments and services. We believe that the renewable energy industry is entering a new phase of growth and that we are well-positioned to serve customers and drive future growth at ALLETE. ALLETE Clean Energy will continue to optimize its existing wind energy facility portfolio, advance and expand its project pipeline, and explore other renewable energy opportunities to further enhance its service offerings, growth and profitability.

In May 2021, ALLETE Clean Energy announced that it acquired the rights to the approximately 92 MW Red Barn wind development project and the approximately 68 MW Whitetail renewable development project in southwestern Wisconsin. ALLETE Clean Energy signed an asset sale agreement for the Red Barn wind project with Wisconsin Public Service Corporation and Madison Gas and Electric Company in 2021. The sale of Red Barn wind project closed in the second quarter of 2023 at which time ALLETE Clean Energy received cash proceeds of approximately $160 million and recorded a gain on sale of $4.3 million after-tax.

Outlook (Continued)
ALLETE Clean Energy

Since September 20, 2023, a substation and the transmission lines feeding that substation located near ALLETE Clean Energy's Caddo wind energy facility, and operated by another party, have experienced a forced outage. This forced outage has increased congestion experienced by the Caddo wind energy facility and is expected to have a negative impact on ALLETE Clean Energy's results in the first quarter of 2024. We will continue to monitor this development for timing of repairs and impact going forward.

ALLETE Clean Energy manages risk by having a diverse portfolio of assets, which includes PSA expiration, technology and geographic diversity. The current operating portfolio is subject to typical variations in seasonal wind with higher wind resources typically available in the winter months. The majority of its planned maintenance leverages this seasonality and is performed during lower wind periods. ALLETE Clean Energy's current operating portfolio is as follows:

Region	Wind Energy Facility	Capacity MW	MW	PSA Expiration
East	Armenia Mountain	101		
	PSA 1		50%	2031
	PSA 2		50%	2024
Midwest	Lake Benton	104	100%	2028
	Storm Lake I	108	100%	2027
	Storm Lake II	77		
	Merchant		90%	n/a
	PSA 1		10%	2032
	Other	17	100%	2028
South	Caddo	303		
	Merchant		27%	n/a
	PSA 1		66%	2034
	PSA 2		7%	2034
	Diamond Spring	303		
	PSA 1		58%	2035
	PSA 2		25%	2032
	PSA 3		16%	2035
West	Condon	50	100%	2028
	Glen Ullin	106	100%	2039
	South Peak	80	100%	2035

Non-cash amortization to revenue recognized by ALLETE Clean Energy relates to the amortization of differences between contract prices and estimated market prices on assumed PSAs. As part of wind energy facility acquisitions, ALLETE Clean Energy assumed various PSAs that were above or below estimated market prices at the time of acquisition; the resulting differences between contract prices and estimated market prices are amortized to revenue over the remaining PSA term. Non-cash amortization is expected to be approximately $5 million in 2024, $6 million in 2025 through 2027, and decreasing thereafter through 2032.

Corporate and Other.

New Energy. New Energy is a renewable energy development company with a primary focus on solar and storage facilities while also offering comprehensive operations, maintenance and asset management services. New Energy is a leading developer of community, commercial and industrial, and small utility-scale renewable energy projects that has completed more than 500 MW in its history, totaling more than $1.2 billion of capital. New Energy currently has a robust project pipeline with greater than 2,000 MW of renewable projects in development across over 20 different states. New Energy adds value through cost effective development and economies of scale on project implementation, bringing national capabilities to regional co-development partners. New Energy is involved in greenfield development as well as acquiring and completing mid-stage and late-stage renewable energy projects.

Investment in Nobles 2. Our subsidiary, ALLETE South Wind, owns a 49 percent equity interest in Nobles 2, the entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota pursuant to a 20-year PPA with Minnesota Power. We account for our investment in Nobles 2 under the equity method of accounting. (See Note 6. Equity Investments.)

Outlook (Continued)
Corporate and Other (Continued)

South Shore Energy. South Shore Energy, ALLETE's non-rate regulated, Wisconsin subsidiary, is developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy. Minnesota Power is expected to purchase approximately 20 percent of the facility's output starting in 2028 pursuant to a capacity dedication agreement. Construction of NTEC is subject to obtaining additional permits from local, state and federal authorities. The total project cost is estimated to be approximately $700 million, of which South Shore Energy will be responsible for approximately 20 percent. South Shore Energy's portion of NTEC project costs incurred through December 31, 2023, is approximately $9 million.

BNI Energy. In 2023, BNI Energy sold 4.0 million tons of coal (3.7 million tons in 2022) and anticipates 2024 sales will be similar to 2023. BNI Energy operates under cost-plus fixed fee agreements extending through December 31, 2037.

ALLETE Properties. Our strategy incorporates the possibility of a bulk sale of the entire ALLETE Properties portfolio. Proceeds from a bulk sale would be strategically deployed to support growth initiatives at our Regulated Operations and ALLETE Clean Energy. ALLETE Properties also continues to pursue sales of individual parcels over time and will continue to maintain key entitlements and infrastructure.

Income Taxes

ALLETE's aggregate federal and multi-state statutory tax rate is approximately 28 percent for 2023. ALLETE also has tax credits and other tax adjustments that reduce the combined statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as production tax credits, excess deferred taxes, non-controlling interests in subsidiaries, as well as other items. The annual effective rate can also be impacted by such items as changes in income before income taxes, state and federal tax law changes that become effective during the year, business combinations, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be an expense of approximately 5 percent for 2024 primarily due to federal production tax credits as a result of wind energy generation and non-controlling interests in subsidiaries. We also expect that our effective tax rate will be lower than the combined statutory rate over the next 10 years due to production tax credits attributable to our wind energy generation.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet its liquidity needs. As of December 31, 2023, we had cash and cash equivalents of $71.9 million, $369.7 million in available consolidated lines of credit, 2.1 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets and a debt-to-capital ratio of 35 percent.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

As of December 31	2023	%	2022	%	2021	%
Millions						
ALLETE Equity	$2,809.6	54	$2,691.9	51	$2,404.3	49
Non-Controlling Interest in Subsidiaries	597.0	11	656.4	12	533.2	11
Short-Term and Long-Term Debt *(a)*	1,799.4	35	1,929.1	37	1,986.4	40
Redeemable Non-Controlling Interest	0.5	—	—	—	—	—
	$5,206.5	100	$5,277.4	100	$4,923.9	100

(a) Excludes unamortized debt issuance costs.

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

Year Ended December 31	2023	2022	2021
Millions			
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$40.2	$47.7	$65.2
Cash Flows from (used in)			
Operating Activities	585.3	221.3	263.5
Investing Activities	(283.6)	(384.0)	(485.2)
Financing Activities	(262.5)	155.2	204.2
Change in Cash, Cash Equivalents and Restricted Cash	39.2	(7.5)	(17.5)
Cash, Cash Equivalents and Restricted Cash at End of Period	$79.4	$40.2	$47.7

Operating Activities. Cash provided by operating activities was higher in 2023 compared to 2022. Cash provided by operating activities in 2023 reflected cash proceeds from the sales of ALLETE Clean Energy's Northern Wind and Red Barn projects which were sold to third parties in 2023, cash received from the favorable arbitration award by a subsidiary of ALLETE Clean Energy, and lower payments for inventories compared to 2022 primarily related to the Northern Wind and Red Barn projects. Cash provided by operating activities in 2023 also increased due to the timing of recovery under Minnesota Power's fuel adjustment clause.

Cash provided by operating activities was lower in 2022 compared to 2021. Cash provided by operating activities in 2022 reflected higher payments for inventories, net of customer deposits received, compared to 2021 primarily related to ALLETE Clean Energy's Northern Wind and Red Barn projects. This decrease was partially offset by the timing of recovery under the fuel adjustment clause.

Investing Activities. Cash used in investing activities was lower in 2023 compared to 2022. Cash used for investing activities in 2023 reflected higher additions to property, plant and equipment compared to 2022. Cash used for investing activities in 2022 reflected cash payments for the acquisition of New Energy.

Cash used in investing activities was lower in 2022 compared to 2021. Cash used for investing activities in 2022 reflected lower additions to property, plant and equipment and lower payments for equity method investments compared to 2021. These decreases were partially offset by cash payments for the acquisition of New Energy.

Financing Activities. Cash used in financing activities in 2023 reflected lower proceeds from the issuance of common stock and the issuance of long-term debt, and lower proceeds from the issuance of non-controlling interest in subsidiaries compared to 2022.

Cash provided by financing activities was lower in 2022 compared to 2021 primarily due to higher repayments of short-term and long-term debt and higher dividends on common stock in 2022. These decreases were partially offset by higher proceeds from the issuance of common stock, higher proceeds from issuance of short-term and long-term debt, and higher proceeds from non-controlling interest in 2022.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit and the issuance of securities, including long-term debt, common stock and commercial paper. As of December 31, 2023, we had consolidated bank lines of credit aggregating $423.1 million ($475.7 million as of December 31, 2022), most of which expire in January 2027. We had $19.4 million outstanding in standby letters of credit and $34.1 million outstanding draws under our lines of credit as of December 31, 2023 ($32.8 million in standby letters of credit and $31.3 million outstanding draws as of December 31, 2022). We also have other credit facility agreements in place that provide the ability to issue up to $252.0 million in standby letters of credit. As of December 31, 2023, we had $130.5 million outstanding in standby letters of credit under these agreements.

In addition, as of December 31, 2023, we had 2.6 million original issue shares of our common stock available for issuance through Invest Direct and 2.1 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets. (See *Securities.*) The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with Lampert Capital Markets, in 2008, as amended most recently in 2020, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 2.1 million shares remain available for issuance as of December 31, 2023. For the year ended December 31, 2023, no shares of common stock were issued under this agreement (none in 2022; 0.8 million shares for net proceeds of $51.0 million in 2021).

During the year ended December 31, 2023, we issued 0.3 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $14.9 million (0.3 million shares for net proceeds of $16.2 million in 2022; 0.3 million shares for net proceeds of $18.9 million in 2021). See Note 10. Common Stock and Earnings Per Share for additional detail regarding ALLETE's equity securities.

Financial Covenants. See Note 8. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. Management considers various factors when making funding decisions, such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the defined benefit pension plans. For the year ended December 31, 2023, we made $17.3 million in cash contributions to the defined benefit pension plans. On January 12, 2024, we contributed $25.0 million in cash to the defined benefit pension plans, and expect to make $2.0 million in additional cash contributions to the defined benefit pension plans in 2024. We do not expect to make any contributions to the defined benefit postretirement health and life plans in 2024. (See Note 10. Common Stock and Earnings Per Share and Note 12. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 9. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. ALLETE has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Material contractual obligations and other commitments are as follows:

Long-Term Debt. ALLETE has material long-term debt obligations, including long-term debt due within one year. These obligations include the principal amount of bonds, notes and loans which are recorded on the Consolidated Balance Sheet, plus interest. (See Note 8. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Pension and other postretirement benefit plan obligations include the current estimate of future benefit payments. Pension contributions are dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, Internal Revenue Service and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. Our obligations are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 12. Pension and Other Postretirement Benefit Plans.)

Operating and Finance Lease Obligations. ALLETE has certain operating and finance lease obligations for the minimum payments required under various lease agreements which are recorded on the Consolidated Balance Sheet. (See Note 1. Operations and Significant Accounting Policies.)

Easement Obligations. ALLETE has easement obligations for the minimum payments required under our land easement agreements at our wind energy facilities. (See Note 9. Commitments, Guarantees and Contingencies.)

PPA Obligations. PPA obligations represent our Square Butte, Manitoba Hydro and other PPAs. (See Note 9. Commitments, Guarantees and Contingencies.)

Other Purchase Obligations. ALLETE has other purchase obligations covering our minimum purchase commitments under coal supply and rail contracts, and long-term service agreements for wind energy facilities. (See Note 9. Commitments, Guarantees and Contingencies.)

Liquidity and Capital Resources (Continued)

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by S&P and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. Our current credit ratings are listed in the following table:

Credit Ratings	S&P	Moody's
Issuer Credit Rating	BBB	Baa1
Commercial Paper	A-2	P-2
First Mortgage Bonds	*(a)*	A2

(a) Not rated by S&P.

The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Common Stock Dividends. ALLETE is committed to providing a competitive dividend to its shareholders while at the same time funding its growth. ALLETE's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. Our targeted payout range is between 60 percent and 70 percent. In 2023, we paid out 63 percent (77 percent in 2022; 78 percent in 2021) of our per share earnings in dividends. On January 26, 2024, our Board of Directors declared a dividend of $0.705 per share, which is payable on March 1, 2024, to shareholders of record at the close of business on February 15, 2024.

Capital Requirements

ALLETE's projected capital expenditures for the years 2024 through 2028 are presented in the following table. Actual capital expenditures may vary from the projections due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies. Projected capital expenditures exclude amounts for projects that will be sold to third parties upon completion.

Capital Expenditures	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Millions						
Regulated Operations						
High kV Transmission Expansion *(a)*	$45	$80	$215	$480	$705	$1,525
Solar RFP *(b)*	35	130	300	100	75	640
Wind RFP *(b)*	5	105	215	300	—	625
Storage *(b)*	—	10	10	10	100	130
Base & Other	225	215	235	270	190	1,135
Regulated Operations	310	540	975	1,160	1,070	4,055
ALLETE Clean Energy *(c)*	15	5	5	5	5	35
Corporate and Other						
South Shore Energy *(d)*	40	55	40	40	10	185
Other	10	15	10	20	15	70
Total Capital Expenditures *(e)*	$375	$615	$1,030	$1,225	$1,100	$4,345

(a) This includes capital expenditures for the HVDC modernization, Northland Reliability, Duluth Loop and Big Stone South transmission projects. (See Outlook – Transmission.)

(b) These capital expenditures are part of Minnesota Power's clean-energy transition plans, which include its vision to deliver 100 percent carbon-free energy to customers by 2050, as detailed in Minnesota Power's latest IRP, which was approved by the MPUC in January 2023. These capital expenditures are dependent on successful requests for proposal by Minnesota Power. (See Outlook – EnergyForward.)

(c) Capital expenditures do not include costs related to developing projects that will be sold upon completion as these costs are accounted for as inventory and reflected in Inventories – Net on the Consolidated Balance Sheet.

(d) Our portion of estimated capital expenditures for construction of NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy.

(e) These amounts do not include capital expenditures for projects considered to be in their preliminary stages.

We are well positioned to meet our financing needs due to adequate operating cash flows, available additional working capital and access to capital markets. We will finance capital expenditures from a combination of internally generated funds, debt and equity issuance proceeds. We intend to maintain a capital structure with capital ratios near current levels. (See *Capital Structure.*)

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have been promulgated by both the EPA and state authorities over the past several years. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation. (See Note 9. Commitments, Guarantees and Contingencies.)

Market Risk

Securities Investments.

Available-for-Sale Securities. As of December 31, 2023, our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits.

Market Risk (Continued)

INTEREST RATE RISK

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. The following table presents the long-term debt obligations and the corresponding weighted average interest rate as of December 31, 2023:

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2024**	**2025**	**2026**	**2027**	**2028**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt								
Fixed Rate – Millions	$94.1	$216.9	$80.2	$162.5	$55.8	$1,144.8	$1,754.3	$1,625.5
Average Interest Rate – %	3.4	3.4	3.5	4.5	3.6	4.2	4.1	
Variable Rate – Millions	$17.3	$27.8	—	—	—	—	$45.1	$45.1
Average Interest Rate – %	8.9	3.9	—	—	—	—	5.8	

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding as of December 31, 2023, an increase of 100 basis points in interest rates would impact the amount of pre-tax interest expense by $0.5 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2023.

COMMODITY PRICE RISK

Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota, and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Minnesota Power's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates or distribution of savings in fuel costs to ratepayers. SWL&P's exposure to price risk for natural gas is significantly mitigated by the current ratemaking process and regulatory framework, which allows the commodity cost to be passed through to customers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

POWER MARKETING

Minnesota Power's power marketing activities consist of: (1) purchasing energy in the wholesale market to serve its regulated service territory when energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, Minnesota Power may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. Minnesota Power actively sells any excess energy to the wholesale market to optimize the value of its generating facilities.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

Recently Adopted Accounting Pronouncements.

New accounting pronouncements are discussed in Note 1. Operations and Significant Accounting Policies.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our Consolidated Financial Statements as of December 31, 2023 and 2022, and for the years ended December 31, 2023, 2022 and 2021, and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2023, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, on the effectiveness of the design and operation of ALLETE's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework (framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2023.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2023, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Trading Plans. For the three months ended December 31, 2023, no director or officer of the Company adopted, modified or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required by this Item is incorporated by reference herein from our Proxy Statement for the 2024 Annual Meeting of Shareholders (2024 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the “Election of Directors” section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the “Corporate Governance” section and the “Audit Committee Report” section;
- **Audit Committee Members.** The identity of the Audit Committee members will be included in the “Corporate Governance” section and the “Audit Committee Report” section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Delinquency.** If applicable, information regarding Section 16(a) delinquencies will be included in a “Delinquent Section 16(a) Reports” section.

Our 2024 Proxy Statement will be filed with the SEC within 120 days after the end of our 2023 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation and Human Capital Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required by this Item is incorporated by reference herein from the “Compensation Discussion and Analysis,” the “Compensation Committee Report,” the “Director Compensation” and the “Pay Versus Performance” sections in our 2024 Proxy Statement.

Information concerning the Company’s policy regarding incentive-based compensation received by current and former officers in the event of a required accounting restatement is included in Exhibit 97 to this Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners" and the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" sections in our 2024 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth the shares of ALLETE common stock available for issuance under the Company's equity compensation plans as of December 31, 2023:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights *(a)*	Weighted-Average Exercise Price of Outstanding Options, Warrants, and Rights *(b)*	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans *(c)*
Equity Compensation Plans Approved by Security Holders	189,646	—	917,149
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	189,646	—	917,149

(a) Includes the following as of December 31, 2023: (i) 29,751 securities representing the performance shares (including accrued dividends) granted under the executive long-term incentive compensation plan that vested but were not paid as of December 31, 2023; (ii) 81,747 securities representing the target number of performance share awards (including accrued dividends) granted under the executive long-term incentive compensation plan that were unvested; and (iii) 78,148 director deferred stock units (including accrued dividends) under the non-employee director compensation deferral plan. With respect to unvested performance share awards, the actual number of shares to be issued will vary from 0 percent to 200 percent of the target level depending upon the achievement of total shareholder return objectives established for such awards. For additional information about the performance shares, including payout calculations, see our 2024 Proxy Statement.

(b) Earned performance share awards are paid in shares of ALLETE common stock on a one-for-one basis. Accordingly, these awards do not have a weighted-average exercise price.

(c) Excludes the number of securities shown in the first column as to be issued upon exercise of outstanding options, warrants, and rights. The amount shown is comprised of: (i) 593,992 shares available for issuance under the executive long-term incentive compensation plan in the form of options, rights, restricted stock units, performance share awards, and other grants as approved by the Executive Compensation Committee of the Company's Board of Directors; (ii) 274,834 shares available for issuance under the Non-Employee Director Stock Plan as payment for a portion of the annual retainer payable to non-employee Directors; and (iii) 48,323 shares available for issuance under the ALLETE and Affiliated Companies Employee Stock Purchase Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is incorporated by reference herein from the "Corporate Governance" section in our 2024 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accountant Fees and Services

Our independent registered public accounting firm is PricewaterhouseCoopers LLP, Minneapolis, MN, PCAOB ID: 238.

The information required by this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2024 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a)	Certain Documents Filed as Part of this Form 10-K.	
(1)	Financial Statements	Page

All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the Consolidated Financial Statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number		
*3(a)1	—	Articles of Incorporation, amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10 Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)4	—	Amendment to Articles of Incorporation, dated as of May 11, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)5	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)		Bylaws, as amended effective April 13, 2020 (filed as Exhibit 3 to the April 14, 2020, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Janet Lee (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)

Exhibit Number					
		Seventeenth	February 1, 1993	33-50143	4(b)
		Eighteenth	July 1, 1993	33-50143	4(c)
		Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
		Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
		Twenty-first	October 1, 2000	333-54330	4(c)3
		Twenty-second	July 1, 2003	1-3548 (June 30, 2003, Form 10-Q)	4
		Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004, Form 10-Q)	4(a)
		Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005, Form 10-Q)	4
		Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006, Form 10-Q)	4
		Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4(a)3
		Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
		Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008, Form 10-Q)	4
		Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
		Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
		Thirty-first	February 1, 2010	1-3548 (March 31, 2010, Form 10-Q)	4
		Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010, Form 10-Q)	4
		Thirty-third	July 1, 2012	1-3548 (July 2, 2012, Form 8-K)	4
		Thirty-fourth	April 1, 2013	1-3548 (April 2, 2013, Form 8-K)	4
		Thirty-fifth	March 1, 2014	1-3548 (March 31, 2014, Form 10-Q)	4
		Thirty-sixth	June 1, 2014	1-3548 (June 30, 2014, Form 10-Q)	4
		Thirty-seventh	September 1, 2014	1-3548 (Sept. 30, 2014, Form 10-Q)	4
		Thirty-eighth	September 1, 2015	1-3548 (Sept. 30, 2015, Form 10-Q)	4(a)
		Thirty-ninth	April 1, 2018	1-3548 (March 31, 2018, Form 10-Q)	4
		Fortieth	March 1, 2019	1-3548 (March 31, 2019, Form 10-Q)	4(a)
		Forty-first	August 1, 2020	1-3548 (Sept. 30, 2020, Form 10-Q)	4(a)
		Forty-second	September 1, 2021	1-3548 (Sept. 30, 2021, Form 10-Q)	4
		Forty-third	August 1, 2022	1-3548 (Sept. 30, 2022, Form 10-Q)	4
		Forty-fourth	April 1, 2023	1-3548 (June 30, 2023, Form 10-Q)	4
*4(b)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).			
*4(b)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:			
		Number	**Dated as of**	**Reference File**	**Exhibit**
		First	March 1, 1951	2-59690	2(d)(1)
		Second	March 1, 1962	2-27794	2(d)1
		Third	July 1, 1976	2-57478	2(e)1
		Fourth	March 1, 1985	2-78641	4(b)
		Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
		Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
		Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
		Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
		Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
		Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
		Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3
		Twelfth	December 2, 2013	1-3548 (2013 Form 10-K)	4(c)3
		Thirteenth	May 29, 2018	1-3548 (June 30, 2018, Form 10-Q)	4
		Fourteenth	June 14, 2021	1-3548 (June 30, 2021, Form 10-Q)	4(a)
		Fifteenth	June 14, 2021	1-3548 (June 30, 2021, Form 10-Q)	4(b)
*4(c)	—	Note Purchase and Guarantee Agreement dated as of November 5, 2015, among Armenia Mountain Wind LLC, AMW I Holding, LLC and the purchasers named therein (filed as Exhibit 4 to the November 12, 2015, Form 8-K, File No. 1-3548).			

Exhibit Number	
*4(d)	— Note Purchase Agreement, dated December 8, 2016, between ALLETE and Hartford Investment Management Company, Northwestern Mutual Investment Management Company, The Northwestern Mutual Life Insurance Company and Nationwide Life insurance Company (filed as Exhibit 4 to the December 12, 2016, Form 8-K, File No. 1-3548).
*4(e)	— Note Purchase Agreement, dated September 10, 2020, between ALLETE and the purchasers named therein (filed as Exhibit 4 to the September 30, 2020, Form 10-Q, File No. 1-3548).
*4(f)	— Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (filed as Exhibit 4(h) to the 2019 Form 10-K, File No. 1-3548).
*10(a)	— Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)1	— Amended and Restated Credit Agreement dated as of January 10, 2019 among ALLETE, as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Chase Bank, N.A., as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 10(b)2 to the 2018 Form 10-K, File No. 1-3548).
*10(b)2	— First Amendment to Credit Agreement dated May 15, 2019, among ALLETE, as Borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4 to the June 30, 2019, Form 10-Q, File No. 1-3548).
*10(b)3	— Second Amendment to Credit Agreement dated November 23, 2021, among ALLETE, as Borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. (filed as Exhibit 10(b)3 to the 2021 Form 10-K, File No. 1-3548).
*10(b)4	— Third Amendment to Credit Agreement dated as of October 17, 2023, among ALLETE, as Borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. (filed as Exhibit 10 to the Sept. 30, 2023, Form 10-Q, File No. 1-3548).
*10(c)1	— Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(c)2	— Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the participating banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(c)3	— First Amendment to Amended and Restated Letter of Credit Agreement, dated as of June 1, 2013, between ALLETE and Wells Fargo Bank, National Association, as Issuing Bank, Administrative Agent and Sole Participating Bank (filed as Exhibit 10(b) to the June 30, 2013, Form 10-Q, File No. 1-3548).
*10(d)	— Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).
*+10(e)1	— ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the 2010 Form 10-K, File No. 1-3548).
*+10(e)2	— ALLETE Executive Annual Incentive Plan Form of Award Effective 2020 (filed as Exhibit 10(e)8 to the 2019 Form 10-K, File No. 1-3548).
*+10(e)3	— ALLETE Executive Annual Incentive Plan Form of Award Effective 2021 (filed as Exhibit 10(e)8 to the 2020 Form 10-K, File No. 1-3548).
*+10(e)4	— ALLETE Executive Annual Incentive Plan Form of Award Effective 2022 (filed as Exhibit 10(e)9 to the 2021 Form 10-K, File No. 1-3548).
*+10(e)5	— ALLETE Executive Annual Incentive Plan Form of Award Effective 2023 (filed as Exhibit 10(e)8 to the 2022 Form 10-K, File No. 1-3548).
*+10(e)6	— ALLETE Executive Annual Incentive Plan Form of Award ALLETE Clean Energy Effective 2023 (filed as Exhibit 10(e)9 to the 2022 Form 10-K, File No. 1-3548).
+10(e)7	— ALLETE Executive Annual Incentive Plan, as amended and restated, effective December 21, 2023.
+10(e)8	— ALLETE Executive Annual Incentive Plan Form of Award Effective 2024.
+10(e)9	— ALLETE Executive Annual Incentive Plan Form of Award ALLETE Clean Energy Effective 2024.
*+10(f)1	— ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
*+10(f)2	— Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the 2010 Form 10-K, File No. 1-3548).
*+10(f)3	— ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2021 (filed as Exhibit 10(f)5 to the 2021 Form 10-K, File No. 1-3548).
+10(f)4	— ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective October 27, 2023.
*+10(g)	— ALLETE Deferred Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(j) to the 2012 Form 10-K, File No. 1-3548).
*+10(h)1	— ALLETE Executive Long-Term Incentive Compensation Plan effective January 1, 2016 (filed November 6, 2015, as Exhibit 99 to Form S-8, File No. 333-207846).
*+10(h)2	— Form of ALLETE Executive Long-Term Incentive Compensation Plan Cash Award Effective 2018 (filed as Exhibit 10(b) to the March 31, 2018, Form 10-Q, File No. 1-3548).

Exhibit Number		
*+10(h)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2018 (filed as Exhibit 10(i)7 to the 2017 Form 10-K, File No. 1-3548).
*+10(h)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2018 (filed as Exhibit 10(i)8 to the 2017 Form 10-K, File No. 1-3548).
*+10(h)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2019 (filed as Exhibit 10(i)10 to the 2018 Form 10-K, File No. 1-3548).
*+10(h)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2019 (filed as Exhibit 10(i)11 to the 2018 Form 10-K, File No. 1-3548).
*+10(h)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2020 (filed as Exhibit 10(i)12 to the 2019 Form 10-K, File No. 1-3548).
*+10(h)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2020 (filed as Exhibit 10(i)13 to the 2019 Form 10-K, File No. 1-3548).
*+10(h)9	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2021 (filed as Exhibit 10(i)14 to the 2020 Form 10-K, File No. 1-3548).
*+10(h)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2021 (filed as Exhibit 10(i)15 to the 2020 Form 10-K, File No. 1-3548).
*+10(h)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2022 (filed as Exhibit 10(i)17 to the 2021 Form 10-K, File No. 1-3548).
*+10(h)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2022 (filed as Exhibit 10(i)18 to the 2021 Form 10-K, File No. 1-3548).
*+10(h)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2023 (filed as Exhibit 10(h)16 to the 2022 Form 10-K, File No. 1-3548).
*+10(h)14	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2023 (filed as Exhibit 10(h)17 to the 2022 Form 10-K, File No. 1-3548).
+10(h)15	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2024.
+10(h)16	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2024.
*+10(i)1	—	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 15, 2013 (filed as Exhibit 10(a) to the June 30, 2013, Form 10-Q, File No. 1-3548).
*+10(i)2	—	ALLETE Non-Employee Director Stock Plan (As Amended and Restated Effective May 10, 2022) (filed as Exhibit 99, File No. 333-265211).
*+10(j)3	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2020 (filed as Exhibit 10(k)3 to the 2020 Form 10-K, File No. 1-3548).
*+10(j)4	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2022 (filed as Exhibit 10(k)4 to the 2021 Form 10-K, File No. 1-3548).
*+10(j)5	—	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 10, 2022 (filed as Exhibit 99 to Form S-8, File No. 333-265211).
+10(j)6	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2023 (filed as Exhibit 10(j)6 to the 2022 Form 10-K, File No. 1-3548).
*+10(k)1	—	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
*+10(k)2	—	Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan, effective October 1, 2003 (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
*+10(k)3	—	Amendment to the ALLETE Director Compensation Deferral Plan, effective January 1, 2005 (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
*+10(k)4	—	Amendment to the ALLETE Director Compensation Deferral Plan, effective October 1, 2006 (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
*+10(k)5	—	Amendment to the ALLETE Director Compensation Deferral Plan, effective July 24, 2012 (filed as Exhibit 10(n)5 to the 2012 Form 10-K, File No. 1-3548).
*+10(l)1	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
*+10(l)2	—	ALLETE Non-Employee Director Compensation Deferral Plan II, as amended and restated, effective July 24, 2012 (filed as Exhibit 10(o)2 to the 2012 Form 10-K, File No. 1-3548).
*+10(m)	—	ALLETE Non-Employee Director Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(p)2 to the 2012 Form 10-K, File No. 1-3548).
*+10(n)1	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective April 23, 2018 (filed as Exhibit 10(c) to the March 31, 2018, Form 10-Q, File No. 1-3548).

Exhibit Number		
+10(n)2	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective October 27, 2023.
21	—	Subsidiaries of the Registrant.
23	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
97	—	Policy Relating to Recovery of Erroneously Awarded Compensation.
99	—	**ALLETE News Release dated February 20, 2024, announcing earnings for the year ended December 31, 2023. (This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**
101.INS	—	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation
104	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, other long-term debt instruments are not filed as exhibits because the total amount of debt authorized under each omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALLETE, Inc.

Dated: February 20, 2024

By /s/ Bethany M. Owen
Bethany M. Owen
Chair, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	**Title**	**Date**
/s/ Bethany M. Owen Bethany M. Owen	Chair, President and Chief Executive Officer (Principal Executive Officer) and Director	February 20, 2024
/s/ Steven W. Morris Steven W. Morris	Senior Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 20, 2024

Signatures (Continued)

Signature	Title	Date
/s/ George G. Goldfarb George G. Goldfarb	Director	February 20, 2024
/s/ James J. Hoolihan James J. Hoolihan	Director	February 20, 2024
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 20, 2024
/s/ Charles R. Matthews Charles R. Matthews	Director	February 20, 2024
/s/ Susan K. Nestegard Susan K. Nestegard	Director	February 20, 2024
/s/ Douglas C. Neve Douglas C. Neve	Director	February 20, 2024
/s/ Barbara A. Nick Barbara A. Nick	Director	February 20, 2024
/s/ Robert P. Powers Robert P. Powers	Director	February 20, 2024
/s/ Charlene A. Thomas Charlene A. Thomas	Director	February 20, 2024

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of ALLETE, Inc. and its subsidiaries (the "Company") as of December 31, 2023 and 2022, and the related consolidated statements of income, of comprehensive income, of equity and of cash flows for each of the three years in the period ended December 31, 2023, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Note 4 to the consolidated financial statements, the Company's regulated utility operations are subject to accounting standards for the effects of certain types of regulation. As of December 31, 2023, there was $435 million of regulatory assets and $578 million of regulatory liabilities recorded. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. Management assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. As disclosed by management, these standards require the Company to reflect the effect of regulatory decisions in its financial statements. This assessment considers factors such as, but not limited to, changes in the regulatory environment and recent rate orders to other regulated entities under the same jurisdiction. If future recovery or refund of costs becomes no longer probable, the assets and liabilities would be recognized in current period net income or other comprehensive income.

The principal consideration for our determination that performing procedures relating to the Company's accounting for the effects of regulatory matters is a critical audit matter is the significant judgment by management in determining the recoverability of costs; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence obtained related to the recoverability of costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's implementation of new regulatory orders, changes to existing regulatory orders, and assessing the recoverability of costs. These procedures also included, among others, evaluating (i) the reasonableness of management's assessment of impacts arising from correspondence with regulators and changes in laws and regulations, (ii) management's judgments related to the recoverability of regulatory assets and the establishment of regulatory liabilities, and (iii) the sufficiency of the disclosures in the consolidated financial statements. Testing the regulatory assets and liabilities involved considering the provisions and formulas outlined in rate orders, other regulatory correspondence, and application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP

Minneapolis, Minnesota
February 20, 2024

We have served as the Company's auditor since 1963.

CONSOLIDATED FINANCIAL STATEMENTS

ALLETE Consolidated Balance Sheet

As of December 31	2023	2022
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$71.9	$36.4
Accounts Receivable (Less Allowance of $1.6 and $1.6)	137.2	137.9
Inventories – Net	175.4	455.9
Prepayments and Other	83.6	87.8
Total Current Assets	468.1	718.0
Property, Plant and Equipment – Net	5,013.4	5,004.0
Regulatory Assets	425.4	441.0
Equity Investments	331.2	322.7
Goodwill and Intangible Assets – Net	155.4	155.6
Other Non-Current Assets	262.9	204.3
Total Assets	$6,656.4	$6,845.6
Liabilities, Redeemable Non-Controlling Interest and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$102.2	$103.0
Accrued Taxes	51.0	69.1
Accrued Interest	21.1	20.5
Long-Term Debt Due Within One Year	111.4	272.6
Other	91.9	251.0
Total Current Liabilities	377.6	716.2
Long-Term Debt	1,679.9	1,648.2
Deferred Income Taxes	192.7	158.1
Regulatory Liabilities	574.0	526.1
Defined Benefit Pension and Other Postretirement Benefit Plans	160.8	179.7
Other Non-Current Liabilities	264.3	269.0
Total Liabilities	3,249.3	3,497.3
Commitments, Guarantees and Contingencies (Note 9)		
Redeemable Non-Controlling Interest	0.5	—
Equity		
ALLETE Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 57.6 and 57.2 Shares Issued and Outstanding	1,803.7	1,781.5
Accumulated Other Comprehensive Loss	(20.5)	(24.4)
Retained Earnings	1,026.4	934.8
Total ALLETE Equity	2,809.6	2,691.9
Non-Controlling Interest in Subsidiaries	597.0	656.4
Total Equity	3,406.6	3,348.3
Total Liabilities, Redeemable Non-Controlling Interest and Equity	$6,656.4	$6,845.6

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2023	2022	2021
Millions Except Per Share Amounts			
Operating Revenue			
Contracts with Customers – Utility	$1,238.3	$1,259.3	$1,227.9
Contracts with Customers – Non-utility	636.4	303.8	179.9
Other – Non-utility	5.1	7.6	11.4
Total Operating Revenue	1,879.8	1,570.7	1,419.2
Operating Expenses			
Fuel, Purchased Power and Gas – Utility	482.9	545.5	562.4
Transmission Services – Utility	88.2	76.7	75.3
Cost of Sales – Non-utility	473.5	182.8	68.8
Operating and Maintenance	345.3	318.9	259.2
Depreciation and Amortization	251.8	242.2	231.7
Taxes Other than Income Taxes	57.2	70.4	70.5
Total Operating Expenses	1,698.9	1,436.5	1,267.9
Operating Income	180.9	134.2	151.3
Other Income (Expense)			
Interest Expense	(80.8)	(75.2)	(69.1)
Equity Earnings	21.7	18.7	20.0
Other	85.0	22.4	8.7
Total Other Income (Expense)	25.9	(34.1)	(40.4)
Income Before Non-Controlling Interest and Income Taxes	206.8	100.1	110.9
Income Tax Expense (Benefit)	27.9	(31.2)	(26.9)
Net Income	178.9	131.3	137.8
Net Loss Attributable to Non-Controlling Interest	(68.2)	(58.0)	(31.4)
Net Income Attributable to ALLETE	$247.1	$189.3	$169.2
Average Shares of Common Stock			
Basic	57.3	55.9	52.4
Diluted	57.4	56.0	52.5
Basic Earnings Per Share of Common Stock	$4.31	$3.38	$3.23
Diluted Earnings Per Share of Common Stock	$4.30	$3.38	$3.23

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Comprehensive Income

Year Ended December 31	2023	2022	2021
Millions			
Net Income	$178.9	$131.3	$137.8
Other Comprehensive Income (Loss)			
Unrealized Gain (Loss) on Securities			
Net of Income Tax Expense (Benefit) of $0.1, $(0.2) and $(0.1)	0.3	(0.4)	(0.1)
Defined Benefit Pension and Other Postretirement Benefit Plans			
Net of Income Tax Expense (Benefit) of $2.4, $(0.1) and $3.0	3.6	(0.2)	7.4
Total Other Comprehensive Income (Loss)	3.9	(0.6)	7.3
Total Comprehensive Income	182.8	130.7	145.1
Net Loss Attributable to Non-Controlling Interest	(68.2)	(58.0)	(31.4)
Total Comprehensive Income Attributable to ALLETE	$251.0	$188.7	$176.5

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2023	2022	2021
Millions			
Operating Activities			
Net Income	$178.9	$131.3	$137.8
Adjustments to Reconcile Net Income to Cash provided by Operating Activities:			
AFUDC – Equity	(3.6)	(2.7)	(2.6)
Income from Equity Investments – Net of Dividends	1.0	2.4	2.2
(Gain) / Loss on Investments and Property, Plant and Equipment	—	1.2	(0.8)
Depreciation Expense	251.7	242.0	231.6
Amortization of PSAs	(5.2)	(7.6)	(11.4)
Amortization of Other Intangible Assets and Other Assets	7.1	8.3	9.9
Deferred Income Tax Expense (Benefit)	17.6	(38.5)	(26.9)
Share-Based and ESOP Compensation Expense	7.3	4.9	5.9
Defined Benefit Pension and Other Postretirement Plan Expense (Benefit)	(6.1)	(3.0)	4.3
Bad Debt Expense	1.3	1.9	1.2
Fuel Adjustment Clause	44.0	15.1	(56.4)
Provision (Payments) for Interim Rate Refund	(18.4)	18.4	—
Changes in Operating Assets and Liabilities			
Accounts Receivable	1.8	(14.0)	(13.0)
Inventories	277.1	(256.1)	(23.5)
Prepayments and Other	(7.9)	(21.5)	(0.5)
Accounts Payable	(4.0)	(1.3)	15.0
Other Current Liabilities	(157.6)	116.2	28.0
Cash Contributions to Defined Benefit Pension Plans	(17.3)	—	(10.3)
Changes in Regulatory and Other Non-Current Assets	15.6	24.1	(12.0)
Changes in Regulatory and Other Non-Current Liabilities	2.0	0.2	(15.0)
Cash provided by Operating Activities	585.3	221.3	263.5
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	1.0	2.2	6.4
Payments for Purchase of Available-for-sale Securities	(1.2)	(2.4)	(3.6)
Acquisitions of Subsidiaries – Net of Cash and Restricted Cash Acquired	—	(155.0)	—
Payments for Equity Investments	(8.2)	(5.9)	(17.6)
Additions to Property, Plant and Equipment	(271.2)	(220.5)	(479.5)
Other Investing Activities	(4.0)	(2.4)	9.1
Cash used in Investing Activities	(283.6)	(384.0)	(485.2)
Financing Activities			
Proceeds from Issuance of Common Stock	14.9	248.0	69.9
Equity Issuance Costs	—	(8.1)	—
Proceeds from Issuance of Short-Term and Long-Term Debt	437.0	785.4	733.0
Repayments of Short-Term and Long-Term Debt	(566.7)	(877.0)	(552.9)
Proceeds from Non-Controlling Interest in Subsidiaries – Net of Issuance Costs	17.8	155.7	90.9
Distributions to Non-Controlling Interest	(8.5)	(1.7)	(3.1)
Dividends on Common Stock	(155.5)	(145.9)	(131.9)
Other Financing Activities	(1.5)	(1.2)	(1.7)
Cash provided (used in) by Financing Activities	(262.5)	155.2	204.2
Change in Cash, Cash Equivalents and Restricted Cash	39.2	(7.5)	(17.5)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	40.2	47.7	65.2
Cash, Cash Equivalents and Restricted Cash at End of Period	$79.4	$40.2	$47.7

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Equity

	2023	2022	2021
Millions Except Per Share Amounts			
Equity			
Common Stock			
Balance, Beginning of Period	$1,781.5	$1,536.7	$1,460.9
Common Stock Issued	22.2	244.8	75.8
Balance, End of Period	1,803.7	1,781.5	1,536.7
Accumulated Other Comprehensive Loss			
Balance, Beginning of Period	(24.4)	(23.8)	(31.1)
Other Comprehensive Income – Net of Income Taxes			
Unrealized Gain (Loss) on Debt Securities	0.3	(0.4)	(0.1)
Defined Benefit Pension and Other Postretirement Plans	3.6	(0.2)	7.4
Balance, End of Period	(20.5)	(24.4)	(23.8)
Retained Earnings			
Balance, Beginning of Period	934.8	891.4	856.0
Net Income Attributable to ALLETE	247.1	189.3	169.2
Common Stock Dividends	(155.5)	(145.9)	(131.9)
Adjustment of Redeemable Non-Controlling Interest	—	—	(1.9)
Balance, End of Period	1,026.4	934.8	891.4
Non-Controlling Interest in Subsidiaries			
Balance, Beginning of Period	656.4	533.2	505.6
Proceeds from Non-Controlling Interest in Subsidiaries – Net of Issuance Costs	9.9	182.9	90.9
Net Loss Attributable to Non-Controlling Interest	(60.8)	(58.0)	(31.4)
Reclassification of Redeemable Non-Controlling Interest to Current Liabilities	—	—	(28.8)
Distributions to Non-Controlling Interest	(8.5)	(1.7)	(3.1)
Balance, End of Period	597.0	656.4	533.2
Total Equity	$3,406.6	$3,348.3	$2,937.5
Redeemable Non-Controlling Interest			
Balance, Beginning of Period	—	—	—
Proceeds from Non-Controlling Interest in Subsidiaries	$7.9	—	—
Net Loss Attributable to Non-Controlling Interest	(7.4)	—	—
Total Redeemable Non-Controlling Interest	$0.5	—	—
Dividends Per Share of Common Stock	$2.71	$2.60	$2.52

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Preparation. References in this report to “we,” “us,” and “our” are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with GAAP. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Actual results could differ from those estimates. The presentation of certain prior period amounts on the Consolidated Financial Statements have been adjusted for comparative purposes.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

Principles of Consolidation. Our Consolidated Financial Statements include the accounts of ALLETE, all of our majority owned subsidiary companies and variable interest entities of which ALLETE is the primary beneficiary. All material intercompany balances and transactions have been eliminated in consolidation.

Variable Interest Entities. The accounting guidance for “Variable Interest Entities” (VIE) is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity’s equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity’s economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity’s expected losses or the right to receive the legal entity’s expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore are the primary beneficiary of that VIE, as defined by the accounting guidance for “Variable Interest Entities.” In determining whether ALLETE is the primary beneficiary of a VIE, management considers whether ALLETE has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. The accounting guidance for VIEs applies to certain ALLETE Clean Energy wind energy facilities, certain New Energy Equity facilities, and our investment in Nobles 2. (See *Tax Equity Financing*.)

Business Segments. We present two reportable segments: Regulated Operations and ALLETE Clean Energy. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 150,000 retail customers. Minnesota Power also has 14 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in seven states, more than 1,200 MW of nameplate capacity wind energy generation with a majority contracted under PSAs of various durations. In addition, ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

Corporate and Other is comprised of New Energy, our investment in Nobles 2, South Shore Energy, BNI Energy, ALLETE Properties, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, land holdings in Minnesota, and earnings on cash and investments.

New Energy is a renewable energy development company with a primary focus on solar and storage facilities while also offering comprehensive operations, maintenance and asset management services.

Our investment in Nobles 2 represents a 49 percent equity interest in Nobles 2, the entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota pursuant to a 20-year PPA with Minnesota Power.

South Shore Energy, ALLETE's non-rate regulated, Wisconsin subsidiary, is developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy. (See Note 3. Jointly-Owned Facilities and Assets.)

BNI Energy mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2023, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under long-term contracts. (See Note 9. Commitments, Guarantees and Contingencies.)

ALLETE Properties represents our legacy Florida real estate investment. Our strategy incorporates the possibility of a bulk sale of the entire ALLETE Properties portfolio. Proceeds from a bulk sale would be strategically deployed to support growth at our Regulated Operations and ALLETE Clean Energy. ALLETE Properties continues to pursue sales of individual parcels over time and will continue to maintain key entitlements and infrastructure.

Cash, Cash Equivalents and Restricted Cash. We consider all investments purchased with original maturities of three months or less to be cash equivalents. As of December 31, 2023, and 2022, restricted cash amounts included in Prepayments and Other on the Consolidated Balance Sheet include deposits required under a tax equity financing agreement and collateral deposits required under an ALLETE Clean Energy loan agreement. The restricted cash amounts included in Other Non-Current Assets represent collateral deposits required under an ALLETE Clean Energy loan agreement and PSAs. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheet that aggregate to the amounts presented in the Consolidated Statement of Cash Flows.

Cash, Cash Equivalents and Restricted Cash

As of December 31	2023	2022	2021
Millions			
Cash and Cash Equivalents	$71.9	$36.4	$45.1
Restricted Cash included in Prepayments and Other	5.1	1.5	0.3
Restricted Cash included in Other Non-Current Assets	2.4	2.3	2.3
Cash, Cash Equivalents and Restricted Cash on the Consolidated Statement of Cash Flows	$79.4	$40.2	$47.7

Supplemental Statement of Cash Flow Information.

Consolidated Statement of Cash Flows

Year Ended December 31	2023	2022	2021
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$80.5	$72.8	$66.8
Cash Paid for Income Taxes	$19.5	$6.0	—
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$2.2	$(9.6)	$(14.0)
Reclassification of Property, Plant and Equipment to Inventory *(a)*	—	$99.7	—
Reclassification of Redeemable Non-Controlling Interest to Current Liabilities *(b)*	—	—	$30.6
Capitalized Asset Retirement Costs	$5.8	$11.8	$16.9
AFUDC–Equity	$3.6	$2.7	$2.6

(a) The decommissioning of the existing Northern Wind assets resulted in a reclassification from Property, Plant and Equipment – Net to Inventories – Net in the second quarter of 2022 as they were repowered and subsequently sold to a subsidiary of Xcel Energy Inc. In the third quarter of 2022, safe harbor equipment was transferred to the project entity resulting in an additional reclassification from Property, Plant and Equipment – Net to Inventories – Net.

(b) Amount reclassified to Current Liabilities resulting from the exercise of an option to buy out a non-controlling interest.

Accounts Receivable. Accounts receivable are reported on the Consolidated Balance Sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific situations and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable **As of December 31**	**2023**	**2022**
Millions		
Trade Accounts Receivable		
Billed	$106.8	$107.1
Unbilled	23.8	29.2
Less: Allowance for Doubtful Accounts	1.6	1.6
Total Trade Accounts Receivable	129.0	134.7
Income Taxes Receivable	8.2	3.2
Total Accounts Receivable	$137.2	$137.9

Concentration of Credit Risk. We are subject to concentration of credit risk primarily as a result of accounts receivable. Minnesota Power sells electricity to eight Large Power Customers. Receivables from these customers totaled $11.2 million as of December 31, 2023 ($11.3 million as of December 31, 2022). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates, which allows us to closely manage collection of amounts due. Minnesota Power's taconite customers, which are currently owned by two entities at the end of 2023, accounted for 32 percent of Regulated Operations operating revenue and 21 percent of consolidated operating revenue in 2023 (32 percent of Regulated Operations operating revenue and 26 percent of consolidated operating revenue in 2022 and 32 percent of Regulated Operations operating revenue and 28 percent of consolidated operating revenue in 2021).

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals.

Available-for-Sale Securities. Available-for-sale debt and equity securities are recorded at fair value. Unrealized gains and losses on available-for-sale debt securities are included in accumulated other comprehensive income (loss), net of tax. Unrealized gains and losses on available-for-sale equity securities are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold.

Inventories – Net. Inventories are stated at the lower of cost or net realizable value. Inventories in our Regulated Operations segment are carried at an average cost or first-in, first-out basis. Inventories in our ALLETE Clean Energy segment and Corporate and Other businesses are carried at an average cost, first-in, first-out or specific identification basis.

Inventories – Net **As of December 31**	**2023**	**2022**
Millions		
Fuel *(a)*	$27.2	$33.4
Materials and Supplies	115.7	75.1
Renewable Energy Facilities Under Development *(b)*	32.5	347.4
Total Inventories – Net	$175.4	$455.9

(a) Fuel consists primarily of coal inventory at Minnesota Power.

(b) Renewable Energy Facilities Under Development consists primarily of project costs related to renewable energy development projects at New Energy. As of December 31, 2022, it consisted primarily of project costs related to ALLETE Clean Energy's Northern Wind and Red Barn wind projects sold in the first quarter of 2023 and the second quarter of 2023, respectively. (See Other Current Liabilities.)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the Consolidated Balance Sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on property, plant and equipment for Corporate and Other operations are recognized when they are retired or otherwise disposed. When property, plant and equipment in our Regulated Operations and ALLETE Clean Energy segments are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for component depreciation except for certain circumstances where the retirement is unforeseen or unexpected. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. Upon MPUC approval of cost recovery, the recognition of AFUDC ceases. (See Note 2. Property, Plant and Equipment.)

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. The MPUC order for Minnesota Power's 2015 IRP directed Minnesota Power to retire Boswell Units 1 and 2, which occurred in the fourth quarter of 2018. As part of the 2016 general retail rate case, the MPUC allowed recovery of the remaining book value of Boswell Units 1 and 2 through 2022. Minnesota Power's latest IRP, which was approved by the MPUC in an order dated January 9, 2023, includes ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Boswell Unit 3 and Unit 4 have a net book value of approximately $220 million and $420 million, respectively, as of December 31, 2023. (See Note 4. Regulatory Matters.) Minnesota Power also retired Taconite Harbor in the first quarter of 2023 consistent with its latest IRP. As part of the 2022 general retail rate case, the MPUC allowed recovery of the remaining book value of Taconite Harbor through 2026. We do not expect to record any impairment charge as a result of these operating changes at Taconite Harbor and Boswell. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives.

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. This includes our property, plant and equipment (see *Property, Plant and Equipment*) and land inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to estimated fair value.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our long lived assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated, and our expectations related to: management's best estimate of future use; sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations.

We continue to monitor changes in the broader energy markets along with wind resource expectations that could indicate impairment at ALLETE Clean Energy wind energy facilities upon contract expirations. A decline in energy prices or lower wind resource expectations could result in a future impairment.

In 2023, 2022 and 2021 there were triggering events identified for our property, plant, and equipment at certain ALLETE Clean Energy wind energy facilities. A recoverability test was performed indicating that the undiscounted cash flows adequately supported the property, plant and equipment book values. As a result, no impairment was recorded in 2023, 2022 or 2021.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage those risks including interest rate risk related to certain variable-rate borrowings, and commodity price and transmission congestion cost risk related to sales to electric customers. We have determined that either these agreements are immaterial to the financial statements, are not derivatives, or, if they are derivatives, the agreements qualify for the normal purchases and normal sales exception to derivative accounting guidance; therefore, derivative accounting is not required.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 13. Employee Stock and Incentive Plans.)

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. Goodwill is assessed annually in the fourth quarter for impairment and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level.

As of the date of our annual goodwill impairment testing in 2023, the Company elected to bypass the qualitative assessment of goodwill for impairment, proceeding directly to the two-step impairment test for the New Energy reporting unit. In performing Step 1 of the impairment test, we compared the fair value of the reporting unit to its carrying value including goodwill. If the carrying value including goodwill were to exceed the fair value of a reporting unit, Step 2 of the impairment test would be performed. Step 2 of the impairment test requires the carrying value of goodwill to be reduced to its fair value, if lower, as of the test date.

For Step 1 of the impairment test, we estimated the reporting unit's fair value using standard valuation techniques, including techniques which use estimates of projected future results and cash flows to be generated by the reporting unit. Such techniques generally include a terminal value that utilizes a growth rate on debt-free cash flows. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. Our annual impairment test in 2023 indicated that the estimated fair value of New Energy exceeded its carrying value, and therefore no impairment existed. The fair value of the reporting unit was determined using a discounted cash flow model, using significant assumptions which included a discount rate of 14 percent, cash flow forecasts through 2028, gross margins, and a terminal growth rate of 3.5 percent.

Other Non-Current Assets

As of December 31	**2023**	**2022**
Millions		
Contract Assets *(a)*	$18.5	$21.0
ALLETE Properties	10.8	19.1
Restricted Cash	2.4	2.3
Other Postretirement Benefit Plans	106.3	58.8
Other	124.9	103.1
Total Other Non-Current Assets	$262.9	$204.3

(a) Contract Assets include payments made to customers as an incentive to execute or extend service agreements. The contract payments are being amortized over the term of the respective agreements as a reduction to revenue.

Other Current Liabilities

As of December 31	**2023**	**2022**
Millions		
Customer Deposits *(a)*	$7.4	$150.7
PSAs	6.0	6.1
Provision for Interim Rate Refund	—	18.4
Manufactured Gas Plant *(b)*	0.8	14.7
Other	77.7	61.1
Total Other Current Liabilities	$91.9	$251.0

(a) Primarily related to deposits received by ALLETE Clean Energy for the Northern Wind project sold in the first quarter of 2023 and the Red Barn wind project sold in the second quarter of 2023. (See Inventories – Net.)

(b) The manufactured gas plant represents the current liability for remediation of a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. (See Note 9. Commitments, Guarantees and Contingencies.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Non-Current Liabilities As of December 31	2023	2022
Millions		
Asset Retirement Obligation *(a)*	$202.9	$200.4
PSAs	20.9	26.9
Other	40.5	41.7
Total Other Non-Current Liabilities	$264.3	$269.0

(a) The asset retirement obligation is primarily related to our Regulated Operations and is funded through customer rates over the life of the related assets. Additionally, BNI Energy funds its obligation through its cost-plus coal supply agreements for which BNI Energy has recorded a receivable of $37.2 million in Other Non-Current Assets on the Consolidated Balance Sheet as of December 31, 2023 ($32.4 million as of December 31, 2022).

Leases. We determine if a contract is, or contains, a lease at inception and recognize a right-of-use asset and lease liability for all leases with a term greater than 12 months. Our right-of-use assets and lease liabilities for operating and finance leases are included in Other Non-Current Assets, Other Current Liabilities and Other Non-Current Liabilities, respectively, in our Consolidated Balance Sheet.

Right-of-use assets represent our right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from the lease. Operating and finance lease right-of-use assets and lease liabilities are recognized at the commencement date based on the estimated present value of lease payments over the lease term. As our leases do not provide an explicit rate, we determine the present value of future lease payments based on our estimated incremental borrowing rate using information available at the lease commencement date. The operating and finance lease right-of-use assets includes lease payments to be made during the lease term and any lease incentives, as applicable.

Our leases may include options to extend or buy out the lease at certain points throughout the term, and if it is reasonably certain at lease commencement that we will exercise that option, we include those rental payments in our calculation of the right-of-use asset and lease liability. Lease and rent expense are recognized on a straight-line basis over the lease term for operating leases. Finance leases recognize interest expense using the interest expense method over the lease term and amortization expense on a straight-line basis over the shorter of the useful life of the asset or the lease term, unless a buy out option is reasonably certain to be exercised, for which we then amortize on a straight-line basis over the useful life of the asset. Leases with a term of 12 months or less are not recognized on the Consolidated Balance Sheet.

The majority of our operating leases are for heavy equipment, vehicles and land with fixed monthly payments which we group into two categories: Vehicles and Equipment; and Land and Other. Our largest operating lease is for the drag line at BNI Energy which includes a termination payment at the end of the lease term if we do not exercise our purchase option. The amount of this payment is $3 million and is included in our calculation of the right-of-use asset and lease liability recorded. None of our other leases contain residual value guarantees. We have one finance lease for heavy equipment which includes a purchase option we are reasonably certain to exercise when the lease terminates.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Leases (Continued)

Additional information on the components of lease cost and presentation of cash flows were as follows:

As December 31	2023	2022
Millions		
Operating Lease Cost	$5.0	$6.3
Finance Lease Cost	$0.1	—
Other Information:		
Operating Cash Flows From Operating Leases	$5.0	$6.3
Financing Cash Flows From Finance Leases	$0.2	—

Additional information related to leases were as follows:

As of December 31	2023	2022
Millions		
Balance Sheet Information Related to Leases:		
Operating Lease Other Non-Current Assets	$10.7	$12.7
Finance Lease Other Non-Current Assets	2.1	—
Total Lease Right-of-use Assets	$12.8	$12.7
Operating Lease Other Current Liabilities	$3.0	$3.2
Finance Lease Other Current Liabilities	0.4	—
Operating Lease Other Non-Current Liabilities	7.7	9.3
Finance Lease Other Non-Current Liabilities	1.6	—
Total Lease Liabilities	$12.7	$12.5
Income Statement Information Related to Leases:		
Operating Lease Rent Expense	$5.0	$6.3
Finance Lease Amortization Expense	0.1	—
Total Operating and Finance Lease Expenses	$5.1	$6.3
Weighted Average Remaining Lease Term (Years):		
Operating Leases - Vehicles and Equipment	3	4
Operating Leases - Land and Other	12	16
Finance Leases - Vehicles and Equipment	5	0
Weighted Average Discount Rate:		
Operating Leases - Vehicles and Equipment	4.0 %	3.9 %
Operating Leases - Land and Other	5.0 %	3.9 %
Finance Leases - Vehicles and Equipment	5.4 %	— %

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Leases (Continued)

Maturities of operating and finance lease liabilities as of December 31, 2023, were as follows:

Millions	Operating	Finance
2024	$3.2	$0.4
2025	3.2	0.4
2026	3.2	0.4
2027	4.1	0.5
2028	0.2	0.6
Thereafter	1.2	—
Total Lease Payments Due	15.1	2.3
Less: Imputed Interest	4.4	0.3
Total Lease Obligations	10.7	2.0
Less: Current Lease Obligations	3.0	0.4
Total Long-term Lease Obligations	$7.7	$1.6

Environmental Liabilities. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers. (See Note 9. Commitments, Guarantees and Contingencies.)

Revenue.

Contracts with Customers – Utility includes sales from our regulated operations for generation, transmission and distribution of electric service, and distribution of water and gas services to our customers. Also included is an immaterial amount of regulated steam generation that is used by customers in the production of paper and pulp.

Contracts with Customers – Non-utility includes sales of goods and services to customers from ALLETE Clean Energy and our Corporate and Other businesses.

Other – Non-utility is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices for PSAs that were assumed during the acquisition of various wind energy facilities.

Revenue Recognition. Revenue is recognized upon transfer of control of promised goods or services to our customers in an amount that reflects the consideration we expect to receive in exchange for those products or services. Revenue is recognized net of allowance for returns and any taxes collected from customers, which are subsequently remitted to the appropriate governmental authorities. We account for shipping and handling activities that occur after the customer obtains control of goods as a cost rather than an additional performance obligation thereby recognizing revenue at time of shipment and accruing shipping and handling costs when control transfers to our customers. We have a right to consideration from our customers in an amount that corresponds directly with the value to the customer for our performance completed to date; therefore, we may recognize revenue in the amount to which we have a right to invoice.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Revenue (Continued)

Nature of Revenue Streams

Utility

Residential and Commercial includes sales for electric, gas or water service to customers, who have implied contracts with the utility, under rates governed by the MPUC, PSCW or FERC. Customers are billed on a monthly cycle basis and revenue is recognized for electric, gas or water service delivered during the billing period. Revenue is accrued for service provided but not yet billed at period end. Performance obligations with these customers are satisfied at time of delivery to customer meters and simultaneously consumed.

Municipal includes sales to 14 non-affiliated municipal customers in Minnesota under long-term wholesale electric contracts. One of these wholesale electric contracts include a termination clause requiring a three-year notice to terminate. These contracts have termination dates ranging through 2037, with a majority of contracts expiring in 2029. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon municipal substation or meter.

Industrial includes sales recognized from contracts with customers in the taconite mining, paper, pulp and secondary wood products, pipeline and other industries. Industrial sales accounted for approximately 55 percent of total regulated utility kWh sales for the year ended December 31, 2023. Within industrial revenue, Minnesota Power had eight Large Power Customer contracts, each serving requirements of 10 MW or more of customer load as of December 31, 2023. These contracts automatically renew past the contract term unless a four-year written notice is given. Large Power Customer contracts have earliest termination dates ranging from 2027 through 2029. We satisfy our performance obligations for these customers at the time energy is delivered to an agreed upon customer substation. Revenue is accrued for energy provided but not yet billed at period end. Based on current contracts with industrial customers, we expect to recognize minimum revenue for the fixed contract components of approximately $62 million per annum through 2027, $15 million in 2028, and $12 million in total thereafter, which reflects the termination notice period in these contracts. When determining minimum revenue, we assume that customer contracts will continue under the contract renewal provision; however, if long-term contracts are renegotiated and subsequently approved by the MPUC or there are changes within our industrial customer class, these amounts may be impacted. Contracts with customers that contain variable pricing or quantity components are excluded from the expected minimum revenue amounts.

Other Power Suppliers includes the sale of energy under a long-term PSA with one customer as well as MISO market and liquidation sales. The expiration date of this PSA is 2028. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon delivery point defined in the contract (generally the MISO pricing node). The current contract with one customer contains variable pricing components that prevent us from estimating future minimum revenue.

Other Revenue includes all remaining individually immaterial revenue streams for Minnesota Power and SWL&P, and is comprised of steam sales to paper and pulp mills, wheeling revenue and other sources. Revenue for steam sales to customers is recognized at the time steam is delivered and simultaneously consumed. Revenue is recognized at the time each performance obligation is satisfied.

CIP Financial Incentive reflects certain revenue that is a result of the achievement of certain objectives for our CIP financial incentives. This revenue is accounted for in accordance with the accounting standards for alternative revenue programs which allow for the recognition of revenue under an alternative revenue program if the program is established by an order from the utility's regulatory commission, the order allows for automatic adjustment of future rates, the amount of revenue recognized is objectively determinable and probable of recovery, and the revenue will be collected within 24 months following the end of the annual period in which it is recognized. CIP financial incentives are recognized in the period in which the MPUC approves the filing, which is typically mid-year.

Non-utility

ALLETE Clean Energy

Long-term PSA revenue includes all sales recognized under long-term contracts for production, curtailment, capacity and associated renewable energy credits from ALLETE Clean Energy wind energy facilities. Expiration dates of these PSAs range from 2024 through 2039. Performance obligations for these contracts are satisfied at the time energy is delivered to an agreed upon point, or production is curtailed at the request of the customer, at specified prices. Revenue from the sale of renewable energy credits is recognized at the same time the related energy is delivered to the customer when sold to the same party.

Sale of Wind Energy Facility includes revenue recognized for the design, development, construction, and sale of a wind energy facility to a customer. Performance obligations for these types of agreements are satisfied at the time the completed project is transferred to the customer at the commercial operation date. Revenue from the sale of a wind energy facility is recognized at the time of asset transfer.

Other is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices on assumed PSAs. As part of wind energy facility acquisitions, ALLETE Clean Energy assumed various PSAs that were above or below estimated market prices at the time of acquisition; the resulting differences between contract prices and estimated market prices are amortized to revenue over the remaining PSA term.

Corporate and Other

Long-term Contract encompasses the sale and delivery of coal to customer generation facilities. Revenue is recognized on a monthly basis at the cost of production plus a specified profit per ton of coal delivered to the customer. Coal sales are secured under long-term coal supply agreements extending through 2037. Performance obligations are satisfied during the period as coal is delivered to customer generation facilities.

Sale of Renewable Development Projects includes revenue recognized from development only and development plus construction type projects that are sold to a customer. For development only projects, revenue is recognized at point in time when all required development responsibilities have been completed and ownership has transferred to the customer. For development plus construction, the transaction price is allocated to two performance obligations based upon the standalone selling price of each obligation. Revenue is recognized on the development performance obligation upon satisfying all required development activities and ownership transferring to the customer. Revenue for the construction performance obligation is recognized over time based on construction costs incurred, beginning at notice to proceed through the commercial operation date.

Other primarily includes revenue from BNI Energy unrelated to coal, revenue from New Energy for asset management services and non-development activities, the sale of real estate from ALLETE Properties, and non-rate base steam generation that is sold for use during production of paper and pulp. Performance obligations are satisfied when control transfers to the customer.

Payment Terms. Payment terms and conditions vary across our businesses. Aside from taconite-producing Large Power Customers, payment terms generally require payment to be made within 15 to 30 days from the end of the period that the service has been rendered. In the case of its taconite-producing Large Power Customers, as permitted by the MPUC, Minnesota Power requires weekly payments for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's estimate of the customers' energy usage, forecasted energy prices and fuel adjustment clause estimates. Minnesota Power's taconite-producing Large Power Customers have generally predictable energy usage on a weekly basis and any differences that occur are trued-up the following month. Due to the timing difference of revenue recognition from the timing of invoicing and payment, the taconite-producing Large Power Customers receive credit for the time value of money; however, we have determined that our contracts do not include a significant financing component as the period between when we transfer the service to the customer and when they pay for such service is minimal.

Assets Recognized From the Costs to Obtain a Contract with a Customer. We recognize as an asset the incremental costs of obtaining a contract with a customer if we expect the benefit of those costs to be longer than one year. We expense incremental costs when the asset that would have resulted from capitalizing these costs would have been amortized in one year or less. As of December 31, 2023, we have $18.5 million of assets recognized for costs incurred to obtain contracts with our customers ($21.0 million as of December 31, 2022). Management determined the amount of costs to be recognized as assets based on actual costs incurred and paid to obtain and fulfill these contracts to provide goods and services to our customers. Assets recognized to obtain contracts are amortized on a straight-line basis over the contract term as a non-cash reduction to revenue. We recognized $2.4 million of non-cash amortization for the year ended December 31, 2023 ($2.4 million for the year end December 31, 2022).

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using a method which approximates the effective interest method.

Tax Equity Financings. Certain subsidiaries of ALLETE have entered into tax equity financings that include forming limited liability companies (LLC) with third-party investors for certain wind and solar projects. Tax equity financings have specific terms that dictate distributions of cash and the allocation of tax attributes among the LLC members, who are divided into two categories: the sponsor and third-party investors. ALLETE subsidiaries are the sponsors in these tax equity financings. The distributions of cash and allocation of tax attributes in these financings generally differ from the underlying ownership percentage interests in the related LLC, with a disproportionate share of tax attributes (including accelerated depreciation and production tax credits) allocated to third-party investors in order to achieve targeted after-tax rates of return, or target yield, from project operations, and a disproportionate share of cash distributions made to the sponsor.

The target yield and other terms vary by tax equity financing. Once the target yield has been achieved or defined time period is met, a “flip point” is recognized. In addition, tax equity financings typically provide that cash distributions can be temporarily increased to the third-party investors in order to meet cumulative distribution thresholds. After the flip point, tax attributes and cash distributions are both typically disproportionately allocated to the sponsor.

Tax equity financings include affirmative and negative covenants that are similar to what a project lender would require in a project financing, such as financial reporting, insurance, maintenance and prudent operator standards. Most covenants are no longer applicable once the flip point occurs and any other obligations of the third-party investor have been eliminated.

The third-party investors’ portions of equity ownership in tax equity LLCs are recorded as non-controlling interest in subsidiaries on the Consolidated Balance Sheet and earnings allocated to third-party investors are recorded as net loss attributable to non-controlling interest on the Consolidated Statement of Income.

Non-Controlling Interest in Subsidiaries and Redeemable Non-Controlling Interest. Non-controlling interest in subsidiaries and redeemable non-controlling interest represent the portion of equity ownership, net income (loss), and comprehensive income (loss) in subsidiaries that is not attributable to equity holders of ALLETE. Non-controlling Interest in Subsidiaries as of and for the years ended December 31, 2023 and 2022, are related to the tax equity financings for ALLETE Clean Energy’s 106 MW Glen Ullin, 80 MW South Peak, 303 MW Diamond Spring and 303 MW Caddo wind energy facilities as well as ALLETE’s equity investment in the 250 MW Nobles 2 wind energy facility. Redeemable Non-Controlling Interest as of and for the year ended December 31, 2023, is related to a tax equity financing entered into in the fourth quarter of 2023 for certain New Energy solar energy facilities totaling 14 MW. This tax equity financing is classified as redeemable non-controlling interest as the redemption price and date are fixed and determinable.

For those wind and solar projects with tax equity financings where the economic benefits are not allocated based on the underlying ownership percentage interests, we have determined that the appropriate methodology for calculating the non-controlling interest in subsidiaries balance is the hypothetical liquidation at book value (HLBV) method. The HLBV method is a balance sheet approach which reflects the substantive economic arrangements in the tax equity financing structures.

Under the HLBV method, amounts reported as non-controlling interest in subsidiaries on the Consolidated Balance Sheet represent the amounts the third-party investors would hypothetically receive at each balance sheet reporting date under the liquidation provisions of the LLC agreements, assuming the net assets of the wind and solar projects were liquidated at amounts determined in accordance with GAAP and distributed to the third-party investor and sponsor. The resulting non-controlling interest in subsidiaries balance in these projects is reported as a component of equity on the Consolidated Balance Sheet as either Non-Controlling Interest in Subsidiaries or Redeemable Non-Controlling Interest.

The results of operations for these projects attributable to non-controlling interest under the HLBV method is determined as the difference in non-controlling interest in subsidiaries and redeemable non-controlling interest on the Consolidated Balance Sheet at the start and end of each reporting period, after taking into account any capital transactions between the projects and the third-party investors.

Factors used in the HLBV calculation include GAAP income, taxable income (loss), tax attributes such as accelerated depreciation, investment tax credits and production tax credits, capital contributions, cash distributions, and the target yield specified in the corresponding LLC agreement. Changes in these factors could have a significant impact on the amounts that third-party investors and sponsors would receive upon a hypothetical liquidation. The use of the HLBV method to allocate income to the non-controlling interest in subsidiaries may create variability in our results of operations as the application of the HLBV method can drive variability in net income or loss attributable to non-controlling interest in subsidiaries from period to period.

Immaterial Out-of-Period Adjustment. In the third quarter of 2023, we recognized a $5.7 million increase in Net Loss Attributable to Non-Controlling Interest on the Consolidated Statement of Income for the correction of an error related to the calculation of non-controlling interest in subsidiaries under the hypothetical liquidation at book value method, of which $3.6 million related to 2022. We have evaluated the effect of this out-of-period adjustment for the current reporting period, as well as on the previous interim and annual periods in which they should have been recognized and concluded that this adjustment is not material to any of the periods affected.

Other Income (Expense) - Other

Year Ended December 31	**2023**	**2022**	**2021**
Millions			
Pension and Other Postretirement Benefit Plan Non-Service Credit *(a)*	$8.9	$9.8	$6.1
Interest and Investment Income *(b)*	10.3	—	2.3
AFUDC - Equity	3.6	2.7	2.6
Gain on Land Sales	0.2	—	0.1
PSA Liability *(c)*	—	10.2	—
Gain on Arbitration Award *(d)*	58.4	—	—
Other	3.6	(0.3)	(2.4)
Total Other Income (Expense) - Other	$85.0	$22.4	$8.7

(a) These are components of net periodic pension and other postretirement benefit cost other than service cost. (See Note 12. Pension and Other Postretirement Benefit Plans.)

(b) Interest and Investment Income for the year ended December 31, 2023, reflects $5.1 million of interest income related to interest awarded as part of an arbitration ruling involving a subsidiary of ALLETE Clean Energy. (See Note 9. Commitments, Guarantees and Contingencies.)

(c) The gain on removal of the PSA liability for the Northern Wind project upon decommissioning of the legacy wind energy facility assets, which was more than offset by a reserve for an anticipated loss on the sale of the Northern Wind project that was recorded in Cost of Sales - Non-Utility on the Consolidated Statement of Income.

(d) This reflects a gain recognized for the favorable outcome of an arbitration ruling involving a subsidiary of ALLETE Clean Energy. (See Note 9. Commitments, Guarantees and Contingencies.)

Income Taxes. ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns. We account for income taxes using the liability method in accordance with GAAP for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal credits related to public utility property. In accordance with GAAP for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 11. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by governmental entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the governmental entity. We account for the collection and payment of these taxes on a net basis.

New Accounting Standards.

Improvements to Reportable Segment Disclosures. In November 2023, the FASB issued Accounting Standards Update 2023-07, *Improvements to Reportable Segment Disclosures* (ASU 2023-07). ASU 2023-07 requires that an entity provide enhanced disclosures about significant segment expenses that are regularly provided to the chief operating decision maker, among other disclosures. ASU 2023-07 is effective for annual periods beginning after December 15, 2023, and for interim periods within annual periods beginning after December 15, 2024, with early adoption permitted.

Improvements to Income Tax Disclosures. In December 2023, the FASB issued Accounting Standards Update 2023-09, *Improvements to Income Tax Disclosures* (ASU 2023-09). ASU 2023-09 was issued to enhance the transparency and decision usefulness of income tax disclosures by disclosing specific categories in the rate reconciliation as well as providing additional information for reconciling items above a threshold. It also requires disclosure about certain income taxes paid. ASU 2023-09 is effective for annual periods beginning after December 15, 2024, with early adoption permitted.

There are no other new accounting standards that we anticipate having a material effect on the presentation of ALLETE's consolidated financial statements.

NOTE 2. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment As of December 31	**2023**	**2022**
Millions		
Regulated Operations		
Property, Plant and Equipment in Service	$5,167.2	$5,198.6
Construction Work in Progress	146.7	74.0
Accumulated Depreciation	(1,969.4)	(1,972.3)
Regulated Operations – Net	3,344.5	3,300.3
ALLETE Clean Energy		
Property, Plant and Equipment in Service	1,612.8	1,619.4
Construction Work in Progress	48.9	51.1
Accumulated Depreciation	(229.1)	(176.8)
ALLETE Clean Energy – Net	1,432.6	1,493.7
Corporate and Other *(a)*		
Property, Plant and Equipment in Service	355.8	295.2
Construction Work in Progress	27.5	50.9
Accumulated Depreciation	(147.0)	(136.1)
Corporate and Other – Net	236.3	210.0
Property, Plant and Equipment – Net	$5,013.4	$5,004.0

(a) Primarily includes BNI Energy and a small amount of non-rate base generation.

NOTE 2. PROPERTY, PLANT AND EQUIPMENT (Continued)

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets.

Estimated Useful Lives of Property, Plant and Equipment (Years)

Regulated Operations			
Generation	4 to 50	ALLETE Clean Energy	5 to 35
Transmission	50 to 75	Corporate and Other	3 to 50
Distribution	18 to 70		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long lived assets that result from the acquisition, construction, development or normal operation of the asset. Asset retirement obligations (AROs) relate primarily to the decommissioning of our coal-fired and wind energy facilities, and land reclamation at BNI Energy. AROs are included in Other Non-Current Liabilities on the Consolidated Balance Sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, the period of remediation is indeterminable and removal liabilities have not been recognized.

Long-standing ratemaking practices approved by applicable state and federal regulatory authorities have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-AROs. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with GAAP for AROs. (See Note 4. Regulatory Matters.)

Asset Retirement Obligations

Millions	
Obligation as of December 31, 2021	$184.5
Accretion	9.5
Liabilities Recognized	7.8
Liabilities Settled	(4.4)
Revisions in Estimated Cash Flows	3.0
Obligation as of December 31, 2022	200.4
Accretion	10.3
Liabilities Settled	(10.2)
Revisions in Estimated Cash Flows	2.4
Obligation as of December 31, 2023	$202.9

NOTE 3. JOINTLY-OWNED FACILITIES AND ASSETS

Boswell Unit 4. Minnesota Power owns 80 percent of the 585 MW Boswell Unit 4. While Minnesota Power operates the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which it and WPPI Energy, the owner of the remaining 20 percent, have equal representation and voting rights. Each owner must provide its own financing and is obligated to its ownership share of operating costs. Minnesota Power's share of operating expenses for Boswell Unit 4 is included in Operating Expenses on the Consolidated Statement of Income.

NOTE 3. JOINTLY-OWNED FACILITIES AND ASSETS (Continued)

Minnesota Power's investments in jointly-owned facilities and assets and the related ownership percentages are as follows:

Regulated Utility Plant	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
As of December 31, 2023				
Boswell Unit 4	$725.9	$369.8	$2.8	80
Transmission Assets	101.0	23.6	—	9.3 - 14.7
Total	$826.9	$393.4	$2.8	
As of December 31, 2022				
Boswell Unit 4	$712.0	$340.1	$3.3	80
Transmission Assets	101.0	21.1	—	9.3 - 14.7
Total	$813.0	$361.2	$3.3	

Nemadji Trail Energy Center. South Shore Energy, ALLETE's non-rate regulated, Wisconsin subsidiary, is developing NTEC, an approximately 600 MW proposed combined-cycle natural gas-fired generating facility to be built in Superior, Wisconsin, which will be jointly owned by Dairyland Power Cooperative, Basin and South Shore Energy. Minnesota Power is expected to purchase approximately 20 percent of the facility's output starting in 2028 pursuant to a capacity dedication agreement. Construction of NTEC is subject to obtaining additional permits from local, state and federal authorities. The total project cost is estimated to be approximately $700 million, of which South Shore Energy will be responsible for approximately 20 percent. South Shore Energy's portion of NTEC project costs incurred through December 31, 2023, is approximately $9 million.

NOTE 4. REGULATORY MATTERS

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, PSCW or FERC. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable and environmental investments and expenditures. (See *Transmission Cost Recovery Rider, Renewable Cost Recovery Rider, Solar Cost Recovery Rider* and *Environmental Improvement Rider*.) Revenue from cost recovery riders was $57.0 million in 2023 ($38.8 million in 2022; $38.9 million in 2021).

Minnesota Retail Rates. Minnesota Power's retail base rates through 2021 were based on a 2018 MPUC retail rate order that allowed for a 9.25 percent return on common equity and a 53.81 percent equity ratio. Interim rates were implemented in Minnesota Power's 2022 general rate case beginning in January 2022, and the resolution of Minnesota Power's 2022 general rate case changed the allowed return on equity to 9.65 percent and the equity ratio to 52.50 percent beginning October 1, 2023. (See *2022 Minnesota General Rate Case*.)

2024 Minnesota General Rate Case. On November 1, 2023, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 12.00 percent for retail customers, net of rider revenue incorporated into base rates. The rate filing seeks a return on equity of 10.30 percent and a 53.00 percent equity ratio. On an annualized basis, the requested final rate increase would generate approximately $89 million in additional revenue. In orders dated December 19, 2023, the MPUC accepted the filing as complete and approved an annual interim rate increase of approximately $64 million, net of rider revenue, beginning January 1, 2024, subject to refund. We cannot predict the level of final rates that may be authorized by the MPUC.

2022 Minnesota General Rate Case. On November 1, 2021, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 18 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $108 million in additional revenue.

In an order dated February 28, 2023, the MPUC made determinations regarding Minnesota Power's general rate case including allowing a return on common equity of 9.65 percent and a 52.50 percent equity ratio. We expect additional revenue from base rates of approximately $60 million and an additional $10 million in revenue recognized under cost recovery riders on an annualized basis. On March 20, 2023, Minnesota Power filed a petition for reconsideration with the MPUC requesting reconsideration and clarification of certain decisions in the MPUC's order. Minnesota Power's petition included requesting reconsideration of the ratemaking treatment of Taconite Harbor and Minnesota Power's prepaid pension asset as well as clarification on interim rate treatment for sales to certain customers that did not operate during 2022. The MPUC denied the requests for reconsideration in an order dated May 15, 2023, and provided clarification in support of the interim rate refund treatment for sales to certain customers that did not operate during 2022.

On June 14, 2023, Minnesota Power appealed to the Minnesota Court of Appeals (Court) specific aspects of the MPUC's rate case orders. Minnesota Power is appealing the ratemaking treatment of Taconite Harbor and Minnesota Power's prepaid pension asset. We are unable to predict the outcome of this proceeding.

In an order dated September 29, 2023, the MPUC approved Minnesota Power's final rates, which were implemented beginning on October 1, 2023. The MPUC order also approved Minnesota Power's interim rate refund plan. Interim rates were collected through the third quarter with reserves recorded as necessary. Minnesota Power recorded a reserve for an interim rate refund of approximately $39 million pre-tax as of September 30, 2023 (approximately $18 million as of December 31, 2022), which was refunded to customers during the fourth quarter of 2023.

FERC-Approved Wholesale Rates. Minnesota Power has wholesale contracts with 14 non-affiliated municipal customers in Minnesota and SWL&P. Two of the wholesale contracts include a termination clause requiring a three-year notice to terminate.

Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through December 31, 2037. The wholesale electric service contract with SWL&P is effective through February 28, 2027. Under the agreement with SWL&P, no termination notice has been given. The rates included in these two contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to Minnesota Power's authorized rate of return for Minnesota retail customers. The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred.

Minnesota Power's wholesale electric contracts with 13 other municipal customers were extended in January 2022 and are effective through 2029. These contracts are based on fixed prices for capacity and energy. The base energy charge for each year is adjusted annually for updated fuel and purchased power costs.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place to charge retail customers on a current basis for certain transmission investments and expenditures, including a return on the capital invested. Current customer billing rates are based on an MPUC order dated December 19, 2023, which provisionally approved Minnesota Power's latest transmission factor filing submitted on October 24, 2023. Updated billing rates were included on customer bills starting in the first quarter of 2024.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place to charge retail customers on a current basis for the costs of certain renewable investments and expenditures, including a return on the capital invested. Customer billing rates for the renewable cost recovery rider had been based on a MPUC order dated January 24, 2023. On March 29, 2023, Minnesota Power submitted its latest renewable cost recovery rider factor filing, which the MPUC approved in an order dated October 3, 2023. Updated billing rates were included on customer bills starting in the fourth quarter of 2023.

Solar Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place to charge retail customers on a current basis for solar costs related to investments and expenditures for meeting the state of Minnesota's solar energy standard. Customer billing rates for the solar cost recovery rider had been based on an August 2022 MPUC order. On August 23, 2023, Minnesota Power submitted its latest solar cost recovery rider factor filing, which the MPUC approved in an order dated December 26, 2023. Updated billing rates were included on customer bills starting in the first quarter of 2024.

Fuel Adjustment Clause. Fuel and purchased power costs related to Minnesota Power's retail customers are recovered from customers through the fuel adjustment clause. The method of accounting for all Minnesota electric utilities is a monthly budgeted, forward-looking fuel adjustment clause with annual prudence review and true-up to actual allowed costs.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Minnesota Power incurred higher fuel and purchased power costs in 2021 than those factored in its fuel adjustment forecast filed in May 2020 for 2021, which resulted in the recognition of an approximately $56 million regulatory asset as of December 31, 2021. The MPUC approved recovery of the regulatory asset in a July 2022 order; recovery of the regulatory asset was completed in 2023.

Minnesota Power incurred higher fuel and purchased power costs in 2022 than those factored in its fuel adjustment forecast filed in May 2021 for 2022, which resulted in the recognition of an approximately $13 million regulatory asset as of December 31, 2022. The MPUC approved recovery of the regulatory asset in an order dated July 31, 2023; recovery of the regulatory asset began in the third quarter of 2023 and will continue through mid-2024.

Minnesota Power incurred lower fuel and purchased power costs in 2023 than those factored in its fuel adjustment forecast filed in May 2022 for 2023, which resulted in the recognition of a $15.5 million regulatory liability as of December 31, 2023. On August 30, 2023, Minnesota Power submitted a filing with the MPUC requesting to refund a portion of over-collected fuel adjustment clause recoveries for 2023 from October 2023 through December 2023. No parties objected to the request and lower rates were implemented in October 2023, subject to final approval by the MPUC which is expected in 2024.

In May 2023, Minnesota Power filed its fuel adjustment forecast for 2024 which was subsequently approved by the MPUC in an order dated November 9, 2023. The fuel and purchase power rates for Minnesota Power retail customers are based on this filing beginning January 1, 2024.

Wisconsin Retail Rates. SWL&P's retail rates through 2022 were based on a December 2018 order by the PSCW that allowed for a return on equity of 10.40 percent and a 55.00 percent equity ratio. The resolution of SWL&P's 2022 general rate case changed the allowed return on equity to 10.00 percent and maintained an equity ratio of 55.00 percent. (See *2022 Wisconsin General Rate Case*.)

2022 Wisconsin General Rate Case. In 2022, SWL&P filed a rate increase request with the PSCW seeking an average increase of 3.60 percent for retail customers. The filing sought an overall return on equity of 10.40 percent and a 55.00 percent equity ratio. On an annualized basis, the requested final rate increase would have generated an estimated $4.3 million in additional revenue. In an order dated December 20, 2022, the PSCW approved an annual increase of $3.3 million reflecting a return on equity of 10.00 percent and 55.00 percent equity ratio. Final rates went into effect January 1, 2023.

Integrated Resource Plan. On February 1, 2021, Minnesota Power filed its latest IRP, which was approved by the MPUC in an order dated January 9, 2023. The approved IRP, which reflects a joint agreement reached with various stakeholders, outlines Minnesota Power's clean-energy transition plans through 2035. These plans include expanding its renewable energy supply, achieving coal-free operations at its facilities by 2035, and investing in a resilient and flexible transmission and distribution grid. As part of these plans, Minnesota Power anticipates adding up to 700 MW of new wind and solar energy resources, and ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Minnesota Power's plans recognize that advances in technology will play a significant role in completing its transition to carbon-free energy supply, reliably and affordably. Minnesota Power is expected to file its next IRP by March 1, 2025.

Solar Energy Request For Proposals. On October 2, 2023, Minnesota Power filed a notice with the MPUC of its intent to issue a request for proposals for up to 300 MW of solar energy resources. Minnesota Power issued the request for proposals on November 15, 2023, which were accepted through January 17, 2024.

Wind Energy Request For Proposals. On December 15, 2023, Minnesota Power filed a notice with the MPUC of its intent to issue a request for proposals for up to 400 MW of wind energy resources. Minnesota Power issued the request for proposals on February 15, 2024.

Energy Conservation and Optimization (ECO) Plan. Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues, excluding revenue received from exempt customers, from service provided in the state on ECOs each year. On April 3, 2023, Minnesota Power submitted its 2022 ECO, formerly known as the conservation improvement program, annual filing detailing Minnesota Power's ECO plan results and proposed financial incentive, which was approved by the MPUC on July 21, 2023. As a result, Minnesota Power recognized revenue of $2.2 million in 2023 for the approved financial incentive ($1.9 million in 2022 and $2.4 million in 2021). The financial incentives are recognized in the period in which the MPUC approves the filing.

On June 30, 2023, Minnesota Power submitted its triennial filing for 2024 through 2026 to the MPUC and Minnesota Department of Commerce, which outlines Minnesota Power’s ECO spending and energy-saving goals for those years. Minnesota Power’s investment goals are $12.5 million for 2024, $12.7 million for 2025 and $12.8 million for 2026.

MISO Return on Equity Complaint. MISO transmission owners, including ALLETE and ATC, have an authorized return on equity of 10.02 percent, or 10.52 percent including an incentive adder for participation in a regional transmission organization based on a 2020 FERC order which is subject to various outstanding legal challenges related to the return on equity calculation and refund period ordered by the FERC. In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the 2020 FERC order back to the FERC. We cannot predict the return on equity the FERC will ultimately authorize in the remanded proceeding. (See Note 6. Equity Investments.)

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions. Minnesota Power has met both parts of the solar mandate to date.

In June 2020, Minnesota Power filed a proposal with the MPUC to accelerate its plans for purchasing solar energy from approximately 20 MW of solar energy projects in Minnesota which was approved in a June 2021 order. These solar energy projects were constructed and owned through an ALLETE subsidiary with an investment of approximately $40 million. Construction of these solar energy projects commenced in 2022 with a portion of these projects placed into service in the fourth quarter of 2022; the remaining project was placed into service in 2023.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to accounting standards for the effects of certain types of regulation. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. With the exception of the regulatory asset for Boswell Units 1 and 2 net plant and equipment, no other regulatory assets are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

NOTE 4. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities As of December 31	2023	2022
Millions		
Current Regulatory Assets *(a)*		
Fuel Adjustment Clause *(b)*	$8.7	$25.6
Other	0.6	—
Total Current Regulatory Assets	$9.3	$25.6
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans *(c)*	$218.6	$225.9
Income Taxes *(d)*	88.1	97.6
Asset Retirement Obligations *(e)*	37.7	35.6
Cost Recovery Riders *(f)*	33.8	41.2
Taconite Harbor *(g)*	20.9	—
Manufactured Gas Plant *(h)*	13.2	15.1
Fuel Adjustment Clause *(b)*	5.0	14.5
PPACA Income Tax Deferral	3.9	4.1
Other	4.2	7.0
Total Non-Current Regulatory Assets	$425.4	$441.0
Current Regulatory Liabilities *(i)*		
Provision for Interim Rate Refund	—	$18.4
Transmission Formula Rates Refund	$1.5	4.9
Other	2.4	0.1
Total Current Regulatory Liabilities	$3.9	$23.4
Non-Current Regulatory Liabilities		
Income Taxes *(d)*	$310.0	$332.5
Wholesale and Retail Contra AFUDC *(j)*	78.0	80.7
Plant Removal Obligations *(k)*	67.0	60.0
Defined Benefit Pension and Other Postretirement Benefit Plans *(c)*	48.6	17.6
Non-Jurisdictional Land Sales *(l)*	30.2	7.5
Fuel Adjustment Clause *(b)*	15.5	—
Investment Tax Credits *(m)*	13.6	16.9
Boswell Units 1 and 2 Net Plant and Equipment *(n)*	6.7	6.7
Other	4.4	4.2
Total Non-Current Regulatory Liabilities	$574.0	$526.1

(a) Current regulatory assets are presented within Prepayments and Other on the Consolidated Balance Sheet.

(b) Fuel adjustment clause regulatory assets and liabilities represent the amount expected to be recovered from or refunded to customers for the under- or over-collection of fuel adjustment clause recoveries. (See Fuel Adjustment Clause.)

(c) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. (See Note 12. Pension and Other Postretirement Benefit Plans.)

(d) These costs represent the difference between deferred income taxes recognized for financial reporting purposes and amounts previously billed to our customers. The balances will primarily decrease over the remaining life of the related temporary differences.

(e) Asset retirement obligations will accrete and be amortized over the lives of the related property with asset retirement obligations.

(f) The cost recovery rider regulatory assets and liabilities are revenue not yet collected from our customers and cash collections from our customers in excess of the revenue recognized, respectively, primarily due to capital expenditures related to Bison and the GNTL as well as differences between production tax credits recognized and those assumed in Minnesota Power's base rates. The cost recovery rider regulatory assets as of December 31, 2023, will be recovered within the next two years.

(g) In the first quarter of 2023, Minnesota Power retired Taconite Harbor Units 1 and 2. The remaining net book value was reclassified from property, plant and equipment to a regulatory asset on the Consolidated Balance Sheet when the units were retired. Minnesota Power expects to receive recovery of the remaining net book value from customers.

(h) This regulatory asset represents costs of remediation for a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. We expect recovery of these remediation costs to be allowed by the PSCW in rates over time.

(i) Current regulatory liabilities are presented within Other Current Liabilities on the Consolidated Balance Sheet.

(j) Wholesale and retail contra AFUDC represents amortization to offset AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable life of the related asset.

(k) Non-legal plant removal obligations included in retail customer rates that have not yet been incurred.

(l) This regulatory liability represents the net proceeds from the sale of certain land by Minnesota Power that is expected to be refunded to ratepayers through a future rate case or through its renewable resources rider.

(m) North Dakota and Federal investment tax credits expected to be realized from Minnesota Power's Bison facility and SWL&P's community solar facility that will be credited to retail customers primarily through future renewable cost recovery rider as the tax credits are utilized.

(n) In 2018, Minnesota Power retired Boswell Units 1 and 2 and reclassified the remaining net book value from property, plant and equipment to a regulatory asset on the Consolidated Balance Sheet. The remaining net book value is currently included in Minnesota Power's rate base and Minnesota Power is earning a return on the outstanding balance.

NOTE 5. ACQUISITIONS

2022 Activity

New Energy. On April 15, 2022, a wholly-owned subsidiary of ALLETE acquired 100 percent of the membership interests of New Energy for a purchase price of $165.5 million. Total consideration of approximately $158.8 million was paid in cash on the acquisition date, which is net of cash acquired and debt assumed. New Energy, which is headquartered in Annapolis, Maryland, is a renewable energy development company with a primary focus on solar and storage facilities while also offering comprehensive operations, maintenance and asset management services. The acquisition of New Energy is consistent with ALLETE's stated strategy of additional investment in renewable energy and related infrastructure across North America to support the Company's sustainability-in-action strategy while providing potential long-term earnings growth.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The allocation of the purchase price, which was finalized in the fourth quarter of 2022, is shown in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis. The goodwill recorded is primarily attributable to the highly skilled workforce of New Energy and synergies expected to arise as a result of the acquisition.

The Company has not presented separate results of operations since closing or combined pro forma financial information of the Company and New Energy since the beginning of 2021, as the results of operations for New Energy are not material to the Company's consolidated financials.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$3.9
Accounts Receivable	1.4
Inventory *(a)*	25.3
Other Current Assets	12.8
Property, Plant and Equipment - Net	16.4
Goodwill *(b)*	154.9
Other Non-Current Assets	2.1
Total Assets Acquired	$216.8
Liabilities Assumed	
Current Liabilities	$23.6
Long-Term Debt Due Within One Year	28.3
Long-Term Debt	5.9
Other Non-Current Liabilities	0.2
Total Liabilities Assumed	$58.0
Net Identifiable Assets Acquired	$158.8

(a) Includes $11.6 million of purchase price accounting for certain projects under development at the time of acquisition.
(b) For tax purpose, the purchase price allocation resulted in $154.9 million of deductible goodwill.

Acquisition-related costs were $2.7 million after-tax, expensed as incurred during 2022 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 6. EQUITY INVESTMENTS

Investment in ATC. Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. In 2023, we invested $8.2 million in ATC. In total, we expect to invest approximately $5.8 million in 2024.

ALLETE's Investment in ATC Year Ended December 31	2023	2022
Millions		
Equity Investment Beginning Balance	$165.4	$154.5
Cash Investments	8.2	5.9
Equity in ATC Earnings	23.1	19.3
Distributed ATC Earnings	(18.3)	(15.5)
Amortization of the Remeasurement of Deferred Income Taxes	1.3	1.2
Equity Investment Ending Balance	$179.7	$165.4

ATC Summarized Financial Data

Balance Sheet Data As of December 31	2023	2022
Millions		
Current Assets	$115.2	$89.6
Non-Current Assets	6,337.0	5,997.8
Total Assets	$6,452.2	$6,087.4
Current Liabilities	$495.9	$511.9
Long-Term Debt	2,736.0	2,613.0
Other Non-Current Liabilities	585.2	485.8
Members' Equity	2,635.1	2,476.7
Total Liabilities and Members' Equity	$6,452.2	$6,087.4

Income Statement Data Year Ended December 31	2023	2022	2021
Millions			
Revenue	$818.9	$751.2	$754.8
Operating Expense	407.6	381.5	376.2
Other Expense	131.7	122.9	113.9
Net Income	$279.6	$246.8	$264.7
ALLETE's Equity in Net Income	$23.1	$19.3	$21.3

ATC's authorized return on equity is 10.02 percent, or 10.52 percent including an incentive adder for participation in a regional transmission organization, based on a 2020 FERC order which is subject to various outstanding legal challenges related to the return on equity calculation and refund period ordered by the FERC. In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the 2020 FERC order back to FERC. As a result of this decision, ATC recorded a reserve in the third quarter of 2022 for anticipated refunds to its customers for approximately $31 million of which our share was approximately $2.4 million pre-tax. We cannot predict the return on equity FERC will ultimately authorize in the remanded proceeding.

In addition, the FERC issued a Notice of Proposed Rulemaking in April 2021 to limit the 50 basis point incentive adder for participation in a regional transmission organization to only the first three years of membership in such an organization. If this proposal is adopted, our equity in earnings from ATC would be reduced by approximately $1 million pre-tax annually.

NOTE 6. EQUITY INVESTMENTS (Continued)

Investment in Nobles 2. Our subsidiary, ALLETE South Wind, owns a 49 percent equity interest in Nobles 2, the entity that owns and operates a 250 MW wind energy facility in southwestern Minnesota pursuant to a 20-year PPA with Minnesota Power. We account for our investment in Nobles 2 under the equity method of accounting.

ALLETE's Investment in Nobles 2	
Millions	
Equity Investment Balance as of December 31, 2022	$157.3
Equity in Nobles 2 Earnings *(a)*	(1.4)
Distributed Nobles 2 Earnings	(4.4)
Equity Investment Balance as of December 31, 2023	$151.5

(a) The Company also recorded net loss attributable to non-controlling interest of $10.2 million related to its investment in Nobles 2.

NOTE 7. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily equity securities.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation and fixed income securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value.

NOTE 7. FAIR VALUE (Continued)

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2023, and December 31, 2022. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of Cash and Cash Equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore is excluded from the recurring fair value measures in the following tables.

	Fair Value as of December 31, 2023			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$8.7	—	—	$8.7
Available-for-sale – Corporate and Governmental Debt Securities *(b)*	—	$6.0	—	6.0
Cash Equivalents	5.8	—	—	5.8
Total Fair Value of Assets	$14.5	$6.0	—	$20.5
Liabilities:				
Deferred Compensation *(c)*	—	$16.5	—	$16.5
Total Fair Value of Liabilities	—	$16.5	—	$16.5

(a) Included in Other Non-Current Assets on the Consolidated Balance Sheet.

(b) As of December 31, 2023, the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $1.3 million, in one year to less than three years was $3.2 million, in three years to less than five years was $1.0 million and in five or more years was $0.5 million.

(c) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.

	Fair Value as of December 31, 2022			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$7.7	—	—	$7.7
Available-for-sale – Corporate and Governmental Debt Securities	—	$5.7	—	5.7
Cash Equivalents	4.2	—	—	4.2
Total Fair Value of Assets	$11.9	$5.7	—	$17.6
Liabilities: *(b)*				
Deferred Compensation	—	$15.0	—	$15.0
Total Fair Value of Liabilities	—	$15.0	—	$15.0

(a) Included in Other Non-Current Assets on the Consolidated Balance Sheet.

(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.

The Company's policy is to recognize transfers in and transfers out of levels as of the actual date of the event or change in circumstances that caused the transfer. For the years ended December 31, 2023 and 2022, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the following table, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed in the following table was based on quoted market prices for the same or similar instruments (Level 2).

Financial Instruments	Carrying Amount	Fair Value
Millions		
Short-Term and Long-Term Debt *(a)*		
December 31, 2023	$1,799.4	$1,670.6
December 31, 2022	$1,929.1	$1,782.7

(a) Excludes unamortized debt issuance costs.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, and property, plant and equipment are measured at fair value when there is an indicator of impairment and recorded at fair value only when an impairment is recognized.

Equity Method Investments. The aggregate carrying amount of our equity investments was $331.2 million as of December 31, 2023 ($322.7 million as of December 31, 2022). The Company assesses our equity investments in ATC and Nobles 2 for impairment whenever events or changes in circumstances indicate that the carrying amount of our investments may not be recoverable. For the years ended December 31, 2023 and 2022, there were no indicators of impairment. (See Note 6. Equity Investments.)

Goodwill. The Company assesses the impairment of goodwill annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. The Company's goodwill is a result of the New Energy acquisition in 2022. (See Note 1. Operations and Significant Accounting Policies and Note 5. Acquisitions.) The aggregate carrying amount of goodwill was $154.9 million as of December 31, 2023.

Property, Plant and Equipment. The Company assesses the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of property, plant, and equipment assets may not be recoverable. (See Note 1. Operations and Significant Accounting Policies.) For the years ended December 31, 2023, and 2022, there was no impairment of property, plant, and equipment.

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. The MPUC order for Minnesota Power's 2015 IRP directed Minnesota Power to retire Boswell Units 1 and 2, which occurred in the fourth quarter of 2018. As part of the 2016 general retail rate case, the MPUC allowed recovery of the remaining book value of Boswell Units 1 and 2 through 2022. Minnesota Power's latest IRP, which was approved by the MPUC in an order dated January 9, 2023, includes ceasing coal operations at Boswell Units 3 and 4 by 2030 and 2035, respectively. Boswell Unit 3 and Unit 4 have a net book value of approximately $220 million and $420 million, respectively, as of December 31, 2023. (See Note 4. Regulatory Matters.) Minnesota Power also retired Taconite Harbor in the first quarter of 2023 consistent with its latest IRP. As part of the 2022 general retail rate case, the MPUC allowed recovery of the remaining book value of Taconite Harbor through 2026. We do not expect to record any impairment charge as a result of these operating changes at Taconite Harbor and Boswell. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives.

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of December 31, 2023, total short-term debt outstanding was $111.4 million ($272.6 million as of December 31, 2022), and consisted of long-term debt due within one year and included $0.1 million of unamortized debt issuance costs.

On October 17, 2023, ALLETE amended its $400 million credit facility (Credit Agreement), which was scheduled to expire in January 2026, to $355 million and extended the expiration date to January 10, 2027. The amended Credit Agreement is unsecured and has a variable interest rate. ALLETE may request a single, one-year extension to the expiration date. Advances may be used by ALLETE for general corporate purposes, to provide liquidity in support of ALLETE's commercial paper program and to issue up to $100 million in letters of credit.

As of December 31, 2023, we had consolidated bank lines of credit aggregating to $423.1 million ($475.7 million as of December 31, 2022), most of which expire in January 2027. We had $19.4 million outstanding in standby letters of credit and $34.1 million outstanding draws under our lines of credit as of December 31, 2023 ($32.8 million in standby letters of credit and $31.3 million outstanding draws as of December 31, 2022).

Long-Term Debt. As of December 31, 2023, total long-term debt outstanding was $1,679.9 million ($1,648.2 million as of December 31, 2022) and included $8.0 million of unamortized debt issuance costs. The aggregate amount of long-term debt maturing in 2024 is $111.4 million; $244.7 million in 2025; $80.2 million in 2026; $162.5 million in 2027; $55.8 million in 2028; and $1,144.8 million thereafter. Substantially all of our regulated electric plant is subject to the lien of the mortgages collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

Minnesota Power is obligated to make financing payments for the Camp Ripley solar array totaling $1.4 million annually during the financing term, which expires in 2027. Minnesota Power has the option at the end of the financing term to renew for a two year term, or to purchase the solar array for approximately $4 million. Minnesota Power anticipates exercising the purchase option when the term expires.

On April 27, 2023, ALLETE issued $125 million of its First Mortgage Bonds (Bonds) to certain institutional buyers in the private placement market. The Bonds, which bear interest at 4.98 percent, will mature in April 2033 and pay interest semi-annually in May and November of each year, commencing on November 1, 2023. ALLETE has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for these types of transactions. Proceeds from the sale of the Bonds were used to refinance existing indebtedness and for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

NOTE 8. SHORT-TERM AND LONG-TERM DEBT (Continued)
Long-Term Debt (Continued)

Long-Term Debt **As of December 31**	**2023**	**2022**
Millions		
First Mortgage Bonds		
6.02% Series Due 2023	—	$75.0
3.69% Series Due 2024	$60.0	60.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
3.20% Series Due 2026	75.0	75.0
5.99% Series Due 2027	60.0	60.0
3.30% Series Due 2028	40.0	40.0
4.08% Series Due 2029	70.0	70.0
3.74% Series Due 2029	50.0	50.0
2.50% Series Due 2030	46.0	46.0
3.86% Series Due 2030	60.0	60.0
2.79% Series Due 2031	100.0	100.0
4.54% Series Due 2032	75.0	75.0
4.98% Series Due 2033	125.0	—
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
4.08% Series Due 2042	85.0	85.0
4.21% Series Due 2043	60.0	60.0
4.95% Series Due 2044	40.0	40.0
5.05% Series Due 2044	40.0	40.0
4.39% Series Due 2044	50.0	50.0
4.07% Series Due 2048	60.0	60.0
4.47% Series Due 2049	30.0	30.0
3.30% Series Due 2050	94.0	94.0
Armenia Mountain Senior Secured Notes 3.26% Due 2024	9.5	19.3
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006, Due 2025	27.8	27.8
Revolving Credit Facility Variable Rate Due 2027	—	13.0
Senior Unsecured Notes 2.65% Due 2025	150.0	150.0
Senior Unsecured Notes 3.11% Due 2027	80.0	80.0
SWL&P First Mortgage Bonds 4.15% Series Due 2028	15.0	15.0
SWL&P First Mortgage Bonds 4.14% Series Due 2048	12.0	12.0
Unsecured Term Loan Variable Rate Due 2023	—	170.0
Other Long-Term Debt, 2023 Weighted Average Rate 5.24% Due 2024 – 2051	95.1	82.0
Unamortized Debt Issuance Costs	(8.1)	(8.3)
Total Long-Term Debt	1,791.3	1,920.8
Less: Due Within One Year	111.4	272.6
Net Long-Term Debt	$1,679.9	$1,648.2

NOTE 8. SHORT-TERM AND LONG-TERM DEBT (Continued)
Long-Term Debt (Continued)

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive financial covenant requires ALLETE to maintain a ratio of indebtedness to total capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00, measured quarterly. As of December 31, 2023, our ratio was approximately 0.36 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. ALLETE has no significant restrictions on its ability to pay dividends from retained earnings or net income. As of December 31, 2023, ALLETE was in compliance with its financial covenants.

NOTE 9. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The following table details the estimated minimum payments for certain long-term commitments as of December 31, 2023:

	2024	2025	2026	2027	2028	Thereafter
Millions						
Capital Purchase Obligations	$73.9	$1.6	$9.9	$38.1	—	$10.5
Easements *(a)*	$8.0	$8.1	$8.1	$8.2	$8.4	$217.7
PPAs *(b)*	$140.7	$133.8	$136.6	$125.7	$132.4	$937.5
Other Purchase Obligations *(c)*	$42.9	—	—	—	—	—

(a) Easement obligations represent the minimum payments for our land easement agreements at our wind energy facilities.
(b) Does not include the Oliver Wind I, Oliver Wind II or Nobles 2 PPAs, as Minnesota Power only pays for energy as it is delivered. (See Power Purchase Agreements.)
(c) Consists of long-term service agreements for wind energy facilities and minimum purchase commitments under coal and rail contracts.

Power Purchase and Sales Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPAs, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our capacity and energy payments.

These agreements have also been evaluated under the accounting guidance for derivatives. We have determined that either these agreements are not derivatives, or, if they are derivatives, the agreements qualify for the normal purchases and normal sales exception to derivative accounting guidance; therefore, derivative accounting is not required.

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on its entitlement to the output of Square Butte's 455 MW coal fired generating unit. Minnesota Power's output entitlement under the Agreement is 50 percent for the remainder of the Agreement, subject to the provisions of the Minnkota Power PSA described in the following table. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2023, Square Butte had total debt outstanding of $171.8 million. Annual debt service for Square Butte is expected to be approximately $33.5 million in 2024, $29.5 million in 2025, $29.6 million in 2026, and $11.9 million in 2027 of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through Minnesota Power's fuel adjustment clause and include the cost of coal purchased from BNI Energy under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2023 was $86.2 million ($82.7 million in 2022; $82.4 million in 2021). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $5.5 million in 2023 ($5.1 million in 2022; $5.8 million in 2021). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnesota Power has also entered into the following long-term PPAs for the purchase of capacity and energy as of December 31, 2023:

Counterparty	Quantity	Product	Commencement	Expiration	Pricing
PPAs					
Calpine Corporation	25 MW	Capacity	June 2019	May 2026	Fixed
Manitoba Hydro					
PPA 1	250 MW	Capacity / Energy	June 2020	May 2035	*(a)*
PPA 2	133 MW	Energy	June 2020	June 2040	Forward Market Prices
Nobles 2	250 MW	Capacity / Energy	December 2020	December 2040	Fixed
Oliver Wind I	*(b)*	Energy	December 2006	December 2040	Fixed
Oliver Wind II	*(b)*	Energy	December 2007	December 2040	Fixed

(a) The capacity price was adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.
(b) The PPAs provide for the purchase of all output from the 50 MW Oliver Wind I and 48 MW Oliver Wind II wind energy facilities.

Minnesota Power has also entered into the following long-term PSAs for the sale of capacity and energy as of December 31, 2023:

Counterparty	Quantity	Product	Commencement	Expiration	Pricing
PSAs					
Basin					
PSA 1	*(a)*	Capacity	June 2022	May 2025	Fixed
PSA 2	100 MW	Capacity	June 2025	May 2028	Fixed
Great River Energy	100 MW	Capacity	June 2022	May 2025	Fixed
Minnkota Power	*(b)*	Capacity / Energy	June 2014	December 2026	*(b)*
Oconto Electric Cooperative	25 MW	Capacity / Energy	January 2019	May 2026	Fixed
Silver Bay Power	*(c)*	Energy	January 2017	December 2031	*(d)*

(a) The agreement provided for 75 MW of capacity from June 1, 2022, through May 31, 2023, and increased to 125 MW of capacity from June 1, 2023, through May 31, 2025.
(b) Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025. Of Minnesota Power's 50 percent output entitlement, it sold to Minnkota Power approximately 37 percent in 2023 (32 percent in 2022 and 28 percent in 2021). (See Square Butte PPA.)
(c) Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power.
(d) The energy pricing escalates at a fixed rate annually and is adjusted for changes in a natural gas index.

Coal, Rail and Shipping Contracts. Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2025. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2024. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state, and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements continue to be promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to new requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many new and proposed state and federal environmental regulations and requirements, potential expenditures for future environmental matters may be material and require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of environmental regulations to project power supply trends and impacts on customers.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers.

Air. The electric utility industry is regulated at the federal and state level to address air emissions. Minnesota Power's thermal generating facilities mainly burn low-sulfur western sub-bituminous coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, baghouses, and low NO_X technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with emission requirements.

Cross-State Air Pollution Rule (CSAPR). The CSAPR requires certain states in the eastern half of the U.S., including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. The CSAPR does not require installation of controls but does require facilities have sufficient allowances to cover their emissions on an annual basis. These allowances are allocated to facilities from each state's annual budget and can be bought and sold. Based on review of the NO_X and SO_2 allowances issued and pending issuance, as well as consideration of current rules, we currently expect generation levels and emission rates will result in continued compliance with the CSAPR. Minnesota Power will continue to monitor ongoing CSAPR rulemakings and compliance implementation, including the EPA's Good Neighbor Rule which modifies certain aspects of the CSAPR's program scope and extent (see *EPA Good Neighbor Plan for 2015 Ozone NAAQS*).

National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with the NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. Minnesota Power actively monitors NAAQS developments, and the EPA is currently reviewing the primary or secondary NAAQS for NO_x, SO_2, and ozone. On February 7, 2024, the EPA announced a final rule lowering the annual primary standard for particulate matter less than 2.5 microns ($PM_{2.5}$) from 12 micrograms per cubic meter (ug/m^3) to 9 ug/m^3, while retaining other existing primary and secondary standards such as those for course particulate matter. The Company is reviewing the new standard to determine potential impacts. Anticipated timelines and compliance costs related to this new standard and other expected NAAQS revisions cannot yet be fully estimated; however, costs could be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

EPA Good Neighbor Plan for 2015 Ozone NAAQS. On June 5, 2023, after disapproving state implementation plans, the EPA published a final Federal Implementation Plan (FIP) rule in the Federal Register, the Good Neighbor Plan, to address regional ozone transport for the 2015 Ozone NAAQS by reducing NOx emissions during the period of May 1 through September 30 (ozone season). In its justification for the final rule, the EPA asserted that 23 states, including Minnesota, were modeled as significant contributors to downwind states' challenges in attaining or maintaining ozone NAAQS compliance. The Good Neighbor Plan is designed to resolve this interstate transport issue by implementing a variety of NOx reduction strategies, including federal implementation plan requirements, NOx emission limitations, and ozone season allowance program requirements. The final rule imposed restrictions on fossil-fuel fired power plants in 22 states and on certain industrial sources in 20 states, with implementation occurring through changes to the existing CSAPR program for power plants.

Since the EPA partially disapproved the Good Neighbor State Implementation Plans (SIPs) for the states of Minnesota and Wisconsin, among others, Minnesota is subject to the final Good Neighbor Plan. However, Minnesota Power and a coalition of other Minnesota utilities and industry (the parties) co-filed challenges to the EPA's final Minnesota SIP disapproval, submitting a petition for reconsideration and stay to the EPA, and a petition for judicial review to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit Court). The parties are challenging and requesting reconsideration of certain technical components of the EPA's review and subsequent partial disapproval of Minnesota's SIP. On July 5, 2023, the Eighth Circuit Court granted the stay preventing the Good Neighbor Plan from taking effect in Minnesota.

On September 29, 2023, the EPA issued an updated final interim rule addressing the stays in Minnesota and five other states, formally delaying the effective date of the final FIP for states with active stays in place. The state of Minnesota was therefore not subject to compliance obligations for the 2023 ozone season. Future compliance obligations will depend on resolution of the stay. Additionally, challenges have been filed against the final FIP rule by the Minnesota coalition parties and other entities, although the Minnesota coalition FIP challenge is currently in abeyance pending resolution of the SIP disapproval case. In February 2024, the U.S. Supreme Court will hear arguments from several states and industry groups requesting a national stay of the FIP rule. Anticipated compliance costs related to final Good Neighbor Plan compliance cannot yet be estimated due to uncertainties about SIP approval resolution, implementation timing, FIP rule outcome, and allowance costs and facility emissions during the ozone season. However, the costs could be material, including costs of additional NO_x controls, emission allowance program participation, or operational changes, if any are required. Minnesota Power would seek recovery of additional costs through a rate proceeding.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters (Industrial Boiler MACT) Rule. A final rule issued by the EPA for Industrial Boiler MACT became effective in 2013 with compliance required at major existing sources in 2016, which applied to Minnesota Power's Hibbard Renewable Energy Center and Rapids Energy Center. Compliance consisted largely of adjustments to fuels and operating practices and compliance costs were not material. After this initial rulemaking, litigation from 2016 through 2018 resulted in court orders directing that the EPA reconsider certain aspects of the regulation. A final rule incorporating these revisions became effective in December 2022, with a compliance deadline of October 6, 2025. Compliance costs are not expected to be material.

EPA Mercury and Air Toxics Standards (MATS) Rule. On April 24, 2023, the EPA published a proposed revision to the existing MATS Rule as part of its mandatory 2020 MATS review. In this proposed rule, the EPA is proposing to alter certain compliance and operational requirements, and to lower several emission limits. Compliance would be required in the 2026 to 2027 timeframe. The EPA expects to issue the final rule in April 2024. The MATS regulation applies at Minnesota Power's Boswell Energy Center, which is currently well-controlled for these emissions and is in full compliance with existing requirements. Compliance costs cannot yet be estimated; however, recovery of any additional costs would be sought through a rate proceeding.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change which creates physical and financial risks. Physical risks could include but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased or other changes in temperatures; increased risk of wildfires; and changes in the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. We are addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expanding renewable power supply for both our operations and the operations of others;
- Providing energy conservation initiatives for our customers and engaging in other demand side management efforts;
- Improving efficiency of our generating facilities;
- Supporting research of technologies to reduce carbon emissions from generating facilities and carbon sequestration efforts;
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas fired generating facilities;
- Managing vegetation on right-of-way corridors to reduce potential wildfire or storm damage risks; and
- Practicing sound forestry management in our service territories to create landscapes more resilient to disruption from climate-related changes, including planting and managing long-lived conifer species.

EPA Regulation of GHG Emissions. On May 23, 2023, the EPA published in the Federal Register proposed regulatory actions under Section 111 of the Clean Air Act (CAA) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). The EPA is proposing to revise new source performance standards (NSPS) for new, modified and reconstructed EGUs (Section 111(b) of the CAA) as well as emission guidelines for certain existing (Section 111(d) of the CAA) EGUs. The EPA is also proposing in this action to officially repeal the predecessor regulation "Affordable Clean Energy Rule", first issued in 2019 and later vacated in 2021. The EPA's Fall 2023 unified agenda identifies the EPA's goal of issuing final regulations in April 2024. The Company will continue to monitor this GHG rulemaking and analyze potential impacts to existing and proposed thermal generating facilities. The rule would apply to several Company assets including existing EGUs at Boswell and Laskin as well as the proposed combined cycle natural gas-fired generating facility, NTEC. Minnesota Power continues implementing its Energy*Forward* strategic plan that provides for significant emissions reductions and diversifying its electricity generation mix to include more renewable and natural gas energy. We are unable to predict compliance costs due to the draft status of the rules and the need for a state implementation plan for Section 111(d) existing units; however, the costs could be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA or delegated state agency for any wastewater discharged to navigable waters. Minnesota Power has obtained all necessary NPDES permits, including NPDES storm water permits, for applicable facilities to conduct operations.

Steam Electric Power Generating Effluent Limitations Guidelines. In 2015, the EPA issued revised federal Effluent Limitation Guidelines (ELG) for steam electric power generating stations under the Clean Water Act. The ELG set effluent limits and prescribed best available control technology for several wastewater streams, including flue gas desulphurization (FGD) water, bottom ash transport water (BATW) and coal combustion landfill leachate. On October 13, 2020, the EPA published a final ELG Rule allowing re-use of bottom ash transport water in FGD scrubber systems and limited discharge for maintaining system water balance. The rule set technology standards and numerical pollutant limits for discharges of BATW and FGD wastewater. Compliance deadlines depend on subcategory, with compliance generally required as soon as possible, beginning after October 13, 2021, but no later than December 31, 2025, or December 31, 2028, in some specific cases.

On March 29, 2023, the EPA published a proposed new ELG rule in the Federal Register to update the 2020 ELGs. In the proposed rule, the EPA is revising ELGs for existing sources, including establishing zero discharge limitations for BATW and FGD wastewater; new limits for combustion residual leachate; and allowing states to set discharge limits for legacy wastewater in surface impoundments. The rule proposes to maintain exemptions for units permanently ceasing coal combustion by 2028 and adds a new subcategory for units that have already complied with either the 2015 or 2020 ELG rules and which will retire by 2032. The EPA plans to publish a final ELG rule in April 2024.

ELG revisions are not expected to have a significant impact on Minnesota Power operations. Boswell, where these ELGs are applicable, completed conversion to dry bottom ash handling and installed a FGD dewatering system in September 2022. The dry conversion projects eliminated bottom ash transport water and minimized wastewater from the FGD system. Re-use and onsite consumption are planned for the remaining BATW and FGD waste stream and for dewatering legacy wastewater from Boswell's existing impoundments. The EPA's reconsideration of legacy wastewater and leachate discharge requirements has the potential to impact dewatering associated with the closed impoundment at Laskin and the closed Taconite Harbor dry ash landfill.

At this time, we estimate no additional material compliance costs for ELG, BATW and FGD requirements. Compliance costs we might incur related to other ELG waste streams (e.g., leachate) or other potential future water discharge regulations at Minnesota Power facilities cannot be estimated; however, the costs could be material, including costs associated with wastewater treatment and re-use. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Permitted Water Discharges – Sulfate. In 2017, the MPCA released a draft water quality standard in an attempt to update Minnesota's existing 10 mg/L sulfate limit for waters used for the production of wild rice with the proposed rulemaking heard before an administrative law judge (ALJ). In 2018, the ALJ rejected significant portions of the proposed rulemaking and the MPCA subsequently withdrew the rulemaking. The existing 10 mg/L limit remains in place, but the MPCA is currently prohibited under state law from listing wild rice waters as impaired or requiring sulfate reduction technology.

The federal Clean Water Act requires the MPCA to update the state's impaired water list every two years. Beginning in 2021 through the latest draft proposed on November 14, 2023, this list now includes Minnesota lakes and streams identified as wild rice waters that are listed for sulfate impairment. The list could subsequently be used to set sulfate limits in discharge permits for power generation facilities and municipal and industrial customers, including paper and pulp facilities, and mining operations. At this time, we are unable to determine the specific impacts these developments may have on Minnesota Power operations or its customers, if any. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act (RCRA) regulates the management and disposal of solid and hazardous wastes. Minnesota Power is required to notify the EPA of hazardous waste activity and routinely submit reports to the EPA.

Coal Ash Management Facilities. Minnesota Power produces the majority of its coal ash at Boswell, with small amounts of ash generated at Hibbard Renewable Energy Center. Ash storage and disposal methods include storing ash in clay-lined onsite impoundments (ash ponds), disposing of dry ash in a lined dry ash landfill, applying ash to land as an approved beneficial use, and trucking ash to state permitted landfills.

Coal Combustion Residuals from Electric Utilities (CCR). In 2015, the EPA published a final rule (2015 Rule) regulating CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) in the Federal Register. The rule included requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. Costs of compliance for Boswell and Laskin are expected to be incurred primarily over the next 12 years and be between approximately $65 million and $120 million. Compliance costs for CCR at Taconite Harbor are not expected to be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Minnesota Power continues to work on minimizing compliance costs through evaluation of beneficial re-use and recycling of CCR. In 2018, a U.S. District Court for the District of Columbia decision vacated specific provisions of the CCR rule, which resulted in a change to the status of several existing clay-lined impoundments at Boswell being considered unlined. In September 2020, the EPA finalized the CCR Part A Rule, which required all unlined impoundments to cease disposal and initiate closure. Upon completion of dry ash conversion activities, Boswell ceased disposal in both impoundments in September 2022. Both impoundments are now inactive and have initiated closure.

On May 17, 2023, the EPA released a proposed rule for CCR legacy surface impoundments. The proposal expands the scope of units regulated under the CCR rule to include legacy ponds (inactive surface impoundments at inactive facilities) and creates a new category of units called CCR management units, which includes inactive and closed impoundments and landfills as well as other non-containerized accumulations of CCR. The proposed rule was published in the Federal Register on May 18, 2023. The EPA is proposing to require that generating facilities evaluate and identify all past deposits of CCR materials on their sites and close or re-close existing CCR units to meet current closure standards, as well as install groundwater monitoring systems, conduct groundwater monitoring, and implement groundwater corrective actions as necessary. A final rule is expected in April 2024. This rule has the potential to impact Boswell and Laskin. Compliance costs for Minnesota Power facilities cannot be estimated at this time; however, the costs could be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Additionally, the EPA released a proposed CCR Part B rulemaking in February 2020 addressing options for beneficial reuse of CCR materials. The final Part B rule expected in late 2024. The final CCR federal permit rule is expected in the first half of 2026. The final federal permit rule will finalize procedures for implementing a CCR federal permit program.

Other Environmental Matters

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. SWL&P has been working with the Wisconsin Department of Natural Resources (WDNR) in determining the extent and location of contamination at the site and surrounding properties. As of December 31, 2023, we have recorded a liability of $1 million for remediation costs at this site. SWL&P has recorded remediation costs for the site as an associated regulatory asset as we expect recovery of these remediation costs to be allowed by the PSCW.

Other Matters

We have multiple credit facility agreements in place that provide the ability to issue standby letters of credit to satisfy our contractual security requirements across our businesses. As of December 31, 2023, we had $149.8 million of outstanding letters of credit issued, including those issued under our revolving credit facility. We do not believe it is likely that any of these outstanding letters of credit will be drawn upon.

Regulated Operations. As of December 31, 2023, we had $24.2 million outstanding in standby letters of credit at our Regulated Operations which are pledged as security to MISO, the NDPSC and a state agency.

ALLETE Clean Energy. ALLETE Clean Energy is party to PSAs that expire in various years between 2024 and 2039. As of December 31, 2023, ALLETE Clean Energy has $91.6 million outstanding in standby letters of credit, the majority of which are pledged as security under these PSAs.

Corporate and Other.

<u>BNI Energy</u>. As of December 31, 2023, BNI Energy had surety bonds outstanding of $82.4 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although its coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. BNI Energy's total reclamation liability is currently estimated at $82.1 million. BNI Energy does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

<u>Investment in Nobles 2</u>. Nobles 2 wind energy facility requires standby letters of credit as security for certain contractual obligations. As of December 31, 2023, ALLETE South Wind has $10.1 million outstanding in standby letters of credit, related to our portion of the security requirements relative to our ownership in Nobles 2.

South Shore Energy. As of December 31, 2023, South Shore Energy had $23.9 million outstanding in standby letters of credit pledged as security in connection with the development of NTEC.

ALLETE Properties. As of December 31, 2023, ALLETE Properties had surety bonds outstanding to governmental entities totaling $2.0 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is $1.0 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

Community Development District Obligations. In 2005, the Town Center District issued $26.4 million of tax-exempt, 6.0 percent capital improvement revenue bonds. The capital improvement revenue bonds are payable over 31 years (by May 1, 2036) and are secured by special assessments on the benefited land. To the extent that ALLETE Properties still owns land at the time of the assessment, it will incur the cost of its portion of these assessments, based upon its ownership of benefited property.

As of December 31, 2023, we owned 33 percent of the assessable land in the Town Center District (42 percent as of December 31, 2022). As of December 31, 2023, ownership levels, our annual assessments related to capital improvement and special assessment bonds for the ALLETE Properties project within the district is approximately $0.7 million. As we sell property at this project, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

In the first quarter of 2023, an ALLETE Clean Energy subsidiary initiated arbitration proceedings seeking damages against a counterparty for non-performance under a contract. Arbitration hearings were held in June and July 2023, and a final arbitration ruling was issued in favor of ALLETE Clean Energy's subsidiary in September 2023. The final arbitration ruling awarded $68.3 million to ALLETE Clean Energy's subsidiary, which included prejudgment interest of $5.1 million, recovery of $3.6 million of arbitration-related costs, and resulted in the recognition of a $58.4 million pre-tax gain in the third quarter of 2023. The arbitration ruling also resulted in the receipt of approximately $60 million of cash, net of distribution to non-controlling interest, in the third quarter of 2023.

NOTE 10. COMMON STOCK AND EARNINGS PER SHARE

Summary of Common Stock	Shares Thousands	Equity Millions
Balance as of December 31, 2020	52,085	$1,460.9
Employee Stock Purchase Plan	17	0.8
Invest Direct	263	17.5
Share-Based Compensation	73	6.5
Equity Issuance Program	782	51.0
Balance as of December 31, 2021	53,220	1,536.7
Employee Stock Purchase Plan	11	0.9
Invest Direct	244	14.9
Share-Based Compensation	82	5.3
Equity Issuance	3,680	223.7
Balance as of December 31, 2022	57,237	1,781.5
Employee Stock Purchase Plan	16	0.8
Invest Direct	232	13.3
Share-Based Compensation	76	8.1
Balance as of December 31, 2023	57,561	$1,803.7

Equity Issuance Program. We entered into a distribution agreement with Lampert Capital Markets, in 2008, as amended most recently in 2020, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 2.1 million shares remain available for issuance as of December 31, 2023. For the year ended December 31, 2023, no shares of common stock were issued under this agreement (none in 2022; 0.8 million for net proceeds of $51.0 million in 2021). On April 5, 2022, ALLETE issued and sold approximately 3.7 million shares of ALLETE common stock. Net proceeds of approximately $224 million were received from the sale of shares. Proceeds were used primarily to fund the acquisition of New Energy and capital investments at ALLETE Clean Energy.

Earnings Per Share. We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from non-vested restricted stock units and performance share awards granted under our Executive Long-Term Incentive Compensation Plan.

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2023			
Net Income Attributable to ALLETE	$247.1		$247.1
Average Common Shares	57.3	0.1	57.4
Earnings Per Share	$4.31		$4.30
2022			
Net Income Attributable to ALLETE	$189.3		$189.3
Average Common Shares	55.9	0.1	56.0
Earnings Per Share	$3.38		$3.38
2021			
Net Income Attributable to ALLETE	$169.2		$169.2
Average Common Shares	52.4	0.1	52.5
Earnings Per Share	$3.23		$3.23

NOTE 11. INCOME TAX EXPENSE

Income Tax Expense Year Ended December 31	2023	2022	2021
Millions			
Current Income Tax Expense *(a)*			
Federal	$9.4	$1.2	—
State	0.9	6.1	—
Total Current Income Tax Expense	$10.3	$7.3	—
Deferred Income Tax Expense (Benefit)			
Federal *(b)*	$(6.0)	$(32.8)	$(37.2)
State *(c)*	24.0	(5.2)	10.8
Investment Tax Credit Amortization	(0.4)	(0.5)	(0.5)
Total Deferred Income Tax Expense (Benefit)	$17.6	$(38.5)	$(26.9)
Total Income Tax Expense (Benefit)	$27.9	$(31.2)	$(26.9)

(a) For the years ended December 31, 2023 and 2022, the federal current tax expense was partially offset by production tax credits and NOLs. For the year ended December 31, 2021, the federal and state current tax expense was minimal due to NOLs.

(b) For the year ended December 31, 2023, the federal deferred income tax benefit was due to tax credits, partially offset by deferred partnership income. For the years ended December 31, 2022 and 2021, the federal deferred income tax benefit is primarily due to production tax credits.

(c) For the year ended December 31, 2022, the state impact includes the benefit of deferred repricing as a result of the New Energy acquisition.

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense Year Ended December 31	2023	2022	2021
Millions			
Income Before Non-Controlling Interest and Income Taxes	$206.8	$100.1	$110.9
Statutory Federal Income Tax Rate	21 %	21 %	21 %
Income Taxes Computed at Statutory Federal Rate	$43.4	$21.0	$23.3
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	19.7	8.6	8.6
Deferred Revaluation – Net of Federal Income Tax Benefit	—	(7.9)	—
Production Tax Credits *(a)*	(31.6)	(50.7)	(53.5)
Investment Tax Credits *(a)*	(5.8)	(4.1)	—
Regulatory Differences – Excess Deferred Tax Benefit	(9.9)	(9.1)	(9.5)
Non-Controlling Interest	13.3	11.2	6.3
AFUDC - Equity	(1.3)	(1.1)	(1.0)
Other	0.1	0.9	(1.1)
Total Income Tax Expense (Benefit)	$27.9	$(31.2)	$(26.9)

(a) For the year ended December 31, 2023, the credits are presented net of any estimated discount on the sale of certain credits.

The effective tax rate was an expense of 13.5 percent for 2023 (benefit of 31.2 percent for 2022; benefit of 24.3 percent for 2021). The 2023, 2022 and 2021 effective tax rates were primarily impacted by production tax credits and non-controlling interests in subsidiaries.

Deferred Income Tax Assets and Liabilities **As of December 31**	**2023**	**2022**
Millions		
Deferred Income Tax Assets		
Employee Benefits and Compensation	$29.3	$46.4
Property-Related	58.1	61.9
NOL Carryforwards	13.0	16.7
Capital Loss Carryforwards	2.1	13.1
Tax Credit Carryforwards	557.4	548.7
Power Sales Agreements	9.0	13.7
Regulatory Liabilities	89.0	95.5
Other	8.7	28.1
Gross Deferred Income Tax Assets	766.6	824.1
Deferred Income Tax Asset Valuation Allowance	(58.0)	(60.2)
Total Deferred Income Tax Assets	$708.6	$763.9
Deferred Income Tax Liabilities		
Deferred Gain	$7.9	$7.9
Property-Related	632.0	661.7
Regulatory Asset for Benefit Obligations	48.1	57.7
Unamortized Investment Tax Credits	29.6	30.0
Partnership Basis Differences	156.5	126.0
Fuel Adjustment Clause	1.9	10.7
Regulatory Assets	25.3	28.0
Total Deferred Income Tax Liabilities	$901.3	$922.0
Net Deferred Income Taxes *(a)*	$192.7	$158.1

(a) Recorded as a net Deferred Income Tax liability on the Consolidated Balance Sheet.

NOL and Tax Credit Carryforwards **As of December 31**	**2023**	**2022**
Millions		
Federal Tax Credit Carryforwards	$480.4	$464.5
Federal Capital Loss Carryforwards *(a)*	—	$35.1
State NOL Carryforwards *(a)*	$280.9	$323.0
State Tax Credit Carryforwards *(b)*	$21.5	$24.5
State Capital Loss Carryforwards *(a)*	—	$83.2

(a) Pre-tax amounts; state NOL carryforwards net of a $10.5 million valuation allowance and state capital loss carryforwards net of a $58.7 million valuation allowance.

(b) Net of a $55.4 million valuation allowance as of December 31, 2023 ($59.6 million as of December 31, 2022).

The federal tax credit carryforward periods expire between 2034 and 2043. We expect to fully utilize the tax credit carryforwards; therefore, no federal valuation allowance has been recognized as of December 31, 2023. The apportioned state NOL, capital loss and tax credit carryforward periods expire between 2024 and 2045. We have established a valuation allowance against certain state NOL, capital loss and tax credits that we do not expect to utilize before their expiration.

Gross Unrecognized Income Tax Benefits	2023	2022	2021
Millions			
Balance at January 1	$1.3	$1.3	$1.4
Reductions for Tax Positions Related to Prior Years	(0.2)	—	(0.1)
Balance as of December 31	$1.1	$1.3	$1.3

Unrecognized tax benefits are the differences between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to the "more-likely-than-not" criteria. The unrecognized tax benefit balance includes permanent tax positions which, if recognized, would affect the annual effective income tax rate. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The gross unrecognized tax benefits as of December 31, 2023, included $0.6 million of net unrecognized tax benefits which, if recognized, would affect the annual effective income tax rate.

As of December 31, 2023, we had accrued interest of $0.1 million (none as of December 31, 2022, and 2021) related to unrecognized tax benefits included on the Consolidated Balance Sheet due to our NOL carryforwards. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses on the Consolidated Statement of Income. Interest expense related to unrecognized tax benefits on the Consolidated Statement of Income was immaterial in 2023, 2022 and 2021. There were no penalties recognized in 2023, 2022 or 2021. The unrecognized tax benefit amounts have been presented as an increase to the net deferred tax liability on the Consolidated Balance Sheet.

No material changes to unrecognized tax benefits are expected during the next 12 months.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE is currently under examination by the state of Minnesota for the tax years 2020 through 2022. ALLETE has no open federal audits, and is no longer subject to federal examination for years before 2020 or state examination for years before 2019. Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns.

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

We have noncontributory union, non-union and combined retiree defined benefit pension plans covering eligible employees. The combined retiree defined benefit pension plan was created in 2016, to include all union and non-union retirees from the existing plans as of January 2016. The plans provide defined benefits based on years of service and final average pay. We made $17.3 million in cash contributions to the plan trusts in 2023 (none in 2022; $10.3 million in 2021). We also have a defined contribution RSOP covering substantially all employees. The 2023 plan year employer contributions totaled $13.7 million ($12.0 million for the 2022 plan year; $11.5 million for the 2021 plan year). (See Note 10. Common Stock and Earnings Per Share and Note 13. Employee Stock and Incentive Plans.)

The non-union defined benefit pension plan was frozen in 2018, and does not allow further crediting of service or earnings to the plan. Further, it is closed to new participants. The Minnesota Power union defined benefit pension plan is also closed to new participants, and the SWL&P union defined benefit pension plan was closed to new participants effective February 1, 2022.

We have postretirement health care and life insurance plans covering eligible employees. In 2010, the postretirement health care plan was closed to employees hired after January 2011, and the eligibility requirements were amended. The postretirement life plan was amended in 2014 to close the plan to non-union employees retiring after 2015, and in 2018, the plan was amended to limit the benefit level for union employees retiring after 2018. In 2023, the postretirement health care plan was amended to change the company contribution to an annual stipend for certain retirees. The postretirement health and life plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and irrevocable grantor trusts. In 2023, no contributions were made to the VEBAs (none in 2022; none in 2021) and no contributions were made to the grantor trusts (none in 2022; none in 2021).

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the pension plans. Contributions are based on estimates and assumptions which are subject to change. On January 12, 2024, we contributed $25.0 million in cash to the defined benefit pension plans, and expect to make $2.0 million in additional cash contributions to the defined benefit pension plans in 2024. We do not expect to make any contributions to the defined benefit postretirement health and life plans in 2024.

Accounting for defined benefit pension and other postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit expense (credit) recognized annually by our regulated utilities are expected to be recovered (refunded) through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset (regulatory liability) on the Consolidated Balance Sheet, in accordance with the accounting standards for the effect of certain types of regulation applicable to our Regulated Operations. The defined benefit pension and postretirement health and life benefit expense (credits) associated with our other operations are recognized in accumulated other comprehensive income.

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Pension Obligation and Funded Status **As of December 31**	**2023**	**2022**
Millions		
Accumulated Benefit Obligation	$729.5	$724.5
Change in Benefit Obligation		
Obligation, Beginning of Year	$739.7	$911.7
Service Cost	6.5	9.3
Interest Cost	40.5	27.2
Plan Amendments	—	0.8
Actuarial (Gain) Loss *(a)*	13.9	(160.6)
Benefits Paid	(60.9)	(58.9)
Participant Contributions	6.6	10.2
Obligation, End of Year	$746.3	$739.7
Change in Plan Assets		
Fair Value, Beginning of Year	$568.6	$745.7
Actual Return on Plan Assets	55.1	(130.5)
Employer Contribution *(b)*	26.2	12.3
Benefits Paid	(60.9)	(58.9)
Fair Value, End of Year	$589.0	$568.6
Funded Status, End of Year	$(157.3)	$(171.1)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(2.1)	$(2.1)
Non-Current Liabilities	$(155.2)	$(169.0)

(a) Actuarial gain in 2022 was primarily the result of increases in discount rates.

(b) Includes Participant Contributions noted above, any contributions made by the Company to pension plan trusts and any direct benefit payments made under certain plans.

The pension costs that are reported as a component within the Consolidated Balance Sheet, reflected in long-term regulatory assets or liabilities and accumulated other comprehensive income, consist of a net loss of $256.9 million as of December 31, 2023 (net loss of $260.2 million and prior service credit of $0.1 million as of December 31, 2022.

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Reconciliation of Net Pension Amounts Recognized in Consolidated Balance Sheet **As of December 31**	**2023**	**2022**
Millions		
Net Loss	$(256.9)	$(260.2)
Prior Service Credit	—	0.1
Accumulated Contributions in Excess of Net Periodic Benefit Cost (Prepaid Pension Asset)	99.6	89.0
Total Net Pension Amounts Recognized in Consolidated Balance Sheet	$(157.3)	$(171.1)

Components of Net Periodic Pension Cost **Year Ended December 31**	**2023**	**2022**	**2021**
Millions			
Service Cost	$6.5	$9.3	$11.0
Non-Service Cost Components *(a)*			
Interest Cost	40.5	27.2	24.6
Expected Return on Plan Assets	(43.8)	(41.5)	(43.4)
Amortization of Loss	5.8	11.4	18.8
Amortization of Prior Service Credit	(0.1)	(0.1)	(0.2)
Net Pension Cost	$8.9	$6.3	$10.8

(a) These components of net periodic pension cost are included in the line item "Other" under Other Income (Expense) on the Consolidated Statement of Income.

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities **Year Ended December 31**	**2023**	**2022**
Millions		
Net Loss	$2.5	$11.4
Amortization of Prior Service Credit	0.1	0.1
Prior Service Credit Arising During the Period	—	0.8
Amortization of Loss	(5.7)	(11.4)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$(3.1)	$0.9

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets **As of December 31**	**2023**	**2022**
Millions		
Projected Benefit Obligation	$746.3	$739.7
Accumulated Benefit Obligation	$729.5	$724.5
Fair Value of Plan Assets	$589.0	$568.6

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Postretirement Health and Life Obligation and Funded Status **As of December 31**	**2023**	**2022**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$110.4	$148.2
Service Cost	2.0	3.0
Interest Cost	5.6	4.4
Actuarial Gain *(a)*	(9.3)	(38.7)
Benefits Paid	(8.1)	(9.2)
Participant Contributions	2.4	2.7
Plan Amendments *(b)*	(29.1)	—
Obligation, End of Year	$73.9	$110.4
Change in Plan Assets		
Fair Value, Beginning of Year	$162.6	$201.8
Actual Return on Plan Assets	20.3	(33.0)
Employer Contribution (Withdrawal)	(3.4)	0.3
Participant Contributions	2.4	2.7
Benefits Paid	(8.1)	(9.2)
Fair Value, End of Year	$173.8	$162.6
Funded Status, End of Year	$99.9	$52.2

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:		
Non-Current Assets	$106.3	$58.8
Current Liabilities	$(0.2)	$(0.2)
Non-Current Liabilities	$(6.2)	$(6.4)

(a) Actuarial gain in 2022 was primarily the result of increases in discount rates.
(b) In 2023, the postretirement health care plan was amended to change the company contribution to an annual stipend for certain retirees.

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the preceding table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $12.8 million in irrevocable grantor trusts included in Other Non-Current Assets on the Consolidated Balance Sheet as of December 31, 2023 ($11.8 million as of December 31, 2022).

The postretirement health and life costs that are reported as a component within the Consolidated Balance Sheet, reflected in regulatory long-term assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs **As of December 31**	**2023**	**2022**
Millions		
Net Gain	$(24.8)	$(9.2)
Prior Service Credit	(33.8)	(13.2)
Total Unrecognized Postretirement Health and Life Cost	$(58.6)	$(22.4)

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Reconciliation of Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet **As of December 31**	**2023**	**2022**
Millions		
Net Gain *(a)*	$24.8	$9.2
Prior Service Credit	33.8	13.2
Accumulated Net Periodic Benefit Cost in Excess of Contributions *(a)*	41.3	29.8
Total Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet	$99.9	$52.2

(a) Excludes gains, losses and contributions associated with irrevocable grantor trusts.

Components of Net Periodic Postretirement Health and Life Cost **Year Ended December 31**	**2023**	**2022**	**2021**
Millions			
Service Cost	$2.0	$3.0	$3.6
Non-Service Cost Components *(a)*			
Interest Cost	5.6	4.4	4.4
Expected Return on Plan Assets	(11.4)	(9.6)	(9.9)
Amortization of (Gain) Loss	(2.7)	0.4	3.0
Amortization of Prior Service Credit	(8.5)	(7.5)	(7.6)
Net Postretirement Health and Life Credit	$(15.0)	$(9.3)	$(6.5)

(a) These components of net periodic postretirement health and life cost are included in the line item "Other" under Other Income (Expense) on the Consolidated Statement of Income.

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities **Year Ended December 31**	**2023**	**2022**
Millions		
Net (Gain) Loss	$(18.3)	$3.9
Prior Service Credit Arising During the Period	(29.1)	—
Amortization of Prior Service Credit	8.4	7.5
Amortization of Gain (Loss)	2.7	(0.4)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$(36.3)	$11.0

Estimated Future Benefit Payments	**Pension**	**Postretirement Health and Life**
Millions		
2024	$58.4	$6.3
2025	$58.1	$6.2
2026	$57.5	$6.1
2027	$57.2	$6.1
2028	$56.9	$6.0
Years 2029 – 2033	$272.6	$30.0

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Weighted Average Assumptions Used to Determine Benefit Obligation **As of December 31**	**2023**	**2022**
Discount Rate		
Pension	5.39%	5.70%
Postretirement Health and Life	5.42%	5.68%
Rate of Compensation Increase	3.52%	3.58%
Health Care Trend Rates		
Trend Rate	7.00%	6.50%
Ultimate Trend Rate	5.00%	5.00%
Year Ultimate Trend Rate Effective	2038	2038

Weighted Average Assumptions Used to Determine Net Periodic Benefit Costs **Year Ended December 31**	**2023**	**2022**	**2021**
Discount Rate			
Pension	5.70%	3.28%	2.87%
Postretirement Health and Life	5.89%	3.09%	2.70%
Expected Long-Term Return on Plan Assets			
Pension	6.83%	6.00%	6.50%
Postretirement Health and Life	6.33%	5.41%	5.85%
Rate of Compensation Increase	3.58%	3.58%	3.62%

In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions, and utilizing the target allocation of our plan assets, forecast the expected long-term rate of return.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans.

The Company utilizes actuarial assumptions about mortality to calculate the pension and postretirement health and life benefit obligations. The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2023, considered a modified PRI-2012 mortality table and MP-2021 mortality projection scale.

Actual Plan Asset Allocations	**Pension**		**Postretirement Health and Life** *(a)*	
	2023	**2022**	**2023**	**2022**
Equity Securities	57%	46%	67%	66%
Fixed Income Securities	40%	50%	33%	34%
Real Estate	3%	4%	—	—
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There were no shares of ALLETE common stock included in pension plan equity securities as of December 31, 2023 (no shares as of December 31, 2022).

The defined benefit pension plans have adopted a dynamic asset allocation strategy (glide path) that increases the invested allocation to fixed income assets as the funding level of the plan increases to better match the sensitivity of the plan's assets and liabilities to changes in interest rates. This is expected to reduce the volatility of reported pension plan expenses. The postretirement health and life plans' assets are diversified to achieve strong returns within managed risk. Equity securities are diversified among domestic companies with large, mid and small market capitalization, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Following are the current targeted allocations as of December 31, 2023:

Plan Asset Target Allocations	**Pension**	**Postretirement Health and Life** *(a)*
Equity Securities	55 %	65 %
Fixed Income Securities	41 %	35 %
Real Estate	4 %	—
	100 %	100 %

(a) Includes VEBAs and irrevocable grantor trusts.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). (See Note 7. Fair Value.)

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

Pension Fair Value

	Fair Value as of December 31, 2023			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	—	$83.7	—	$83.7
U.S. Mid-cap Growth *(a)*	—	69.9	—	69.9
U.S. Small-cap *(a)*	—	46.5	—	46.5
International	$134.6	—	—	134.6
Fixed Income Securities *(a)*	—	215.0	—	215.0
Cash and Cash Equivalents	20.4	—	—	20.4
Real Estate	—	—	$18.9	18.9
Total Fair Value of Assets	$155.0	$415.1	$18.9	$589.0

(a) The underlying investments consist of actively-managed funds managed to achieve the returns of certain U.S. equity and fixed income securities indexes.

Recurring Fair Value Measures

Activity in Level 3	**Real Estate**
Millions	
Balance as of December 31, 2022	$22.4
Actual Return on Plan Assets	(3.1)
Purchases, Sales, and Settlements – Net	(0.4)
Balance as of December 31, 2023	$18.9

	Fair Value as of December 31, 2022			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	—	$61.2	—	$61.2
U.S. Mid-cap Growth *(a)*	—	40.0	—	40.0
U.S. Small-cap *(a)*	—	35.4	—	35.4
International	$127.0	—	—	127.0
Fixed Income Securities *(a)*	—	275.3	—	275.3
Cash and Cash Equivalents	7.3	—	—	7.3
Real Estate	—	—	$22.4	22.4
Total Fair Value of Assets	$134.3	$411.9	$22.4	$568.6

(a) The underlying investments consist of actively-managed funds managed to achieve the returns of certain U.S. equity and fixed income securities indexes.

Recurring Fair Value Measures

Activity in Level 3	**Real Estate**
Millions	
Balance as of December 31, 2021	$21.6
Actual Return on Plan Assets	1.0
Purchases, Sales, and Settlements – Net	(0.2)
Balance as of December 31, 2022	$22.4

Postretirement Health and Life Fair Value

	Fair Value as of December 31, 2023			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$30.0	—	—	$30.0
U.S. Mid-cap Growth	28.7	—	—	28.7
U.S. Small-cap	14.9	—	—	14.9
International	41.9	—	—	41.9
Fixed Income Securities:				
Mutual Funds	55.1	—	—	55.1
Cash and Cash Equivalents	3.2	—	—	3.2
Total Fair Value of Assets	$173.8	—	—	$173.8

(a) The underlying investments consist of mutual funds (Level 1).

	Fair Value as of December 31, 2022			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$26.7	—	—	$26.7
U.S. Mid-cap Growth	25.5	—	—	25.5
U.S. Small-cap	12.7	—	—	12.7
International	41.5	—	—	41.5
Fixed Income Securities:				
Mutual Funds	55.5	—	—	55.5
Cash and Cash Equivalents	0.7	—	—	0.7
Total Fair Value of Assets	$162.6	—	—	$162.6

(a) The underlying investments consist of mutual funds (Level 1).

Recurring Fair Value Measures

Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2021	$2.0
Actual Return on Plan Assets	(1.5)
Purchases, Sales, and Settlements – Net	(0.5)
Balance as of December 31, 2022	—

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide a fully insured postretirement health benefit, including a prescription drug benefit, which qualifies us for a federal subsidy under the Act. The federal subsidy is reflected in the premiums charged to us by the insurance company.

NOTE 13. EMPLOYEE STOCK AND INCENTIVE PLANS

Employee Stock Ownership Plan. We sponsor an ESOP within the RSOP. Eligible employees may contribute to the RSOP plan as of their date of hire. The dividends received by the ESOP are distributed to participants. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings. ESOP employer allocations are funded with contributions paid in either cash or the issuance of ALLETE common stock at the Company's discretion. We record compensation expense equal to the cash or current market price of stock contributed. ESOP compensation expense was $13.7 million in 2023 ($12.0 million in 2022; $11.5 million in 2021).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock held and purchased by the ESOP were treated as unearned ESOP shares and not considered outstanding for earnings per share computations. All ESOP shares have been allocated to participants as of December 31, 2023, 2022 and 2021.

Stock-Based Compensation.

Stock Incentive Plan. Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, restricted stock units, stock appreciation rights and other awards. There are 0.7 million shares of ALLETE common stock reserved for issuance under the Executive Plan, of which 0.6 million of these shares remain available for issuance as of December 31, 2023.

The following types of share-based awards were outstanding in 2023, 2022 or 2021:

Performance Shares. Under the performance share awards, the number of shares earned is contingent upon attaining specific market and performance goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies while performance goals are measured by earnings per share growth. In the case of qualified retirement, death, or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death, or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards incorporates the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock unit awards, shares for participants eligible for retirement vest monthly over a three-year period. For participants not eligible for retirement, shares vest at the end of the three-year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be earned. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price; we are not required to apply fair value accounting to these awards as the discount is not greater than 5 percent.

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our Consolidated Statement of Income for the periods presented.

Share-Based Compensation Expense **Year Ended December 31**	**2023**	**2022**	**2021**
Millions			
Performance Shares	$3.1	$0.7	$2.0
Restricted Stock Units	0.8	0.9	1.0
Total Share-Based Compensation Expense	$3.9	$1.6	$3.0
Income Tax Benefit	$1.1	$0.5	$0.9

There were no capitalized share-based compensation costs during the years ended December 31, 2023, 2022 or 2021.

As of December 31, 2023, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our Consolidated Statement of Income was $2.6 million and $0.8 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years and 1.7 years, respectively.

NOTE 13. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Performance Shares. The following table presents information regarding our non-vested performance shares.

	2023		2022		2021	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1	60,489	$69.62	80,661	$75.80	85,284	$80.73
Granted *(a)*	54,039	$63.50	37,731	$67.22	33,304	$73.25
Awarded	—	—	—	—	—	—
Unearned Grant Award	—	—	(50,524)	$77.49	(33,375)	$86.09
Forfeited	(3,030)	$67.60	(7,379)	$71.00	(4,552)	$74.05
Non-vested as of December 31	111,498	$66.71	60,489	$69.62	80,661	$75.80

(a) Shares granted include accrued dividends.

There were approximately 61,900 performance shares granted in January 2024 for the three-year performance period ending in 2026. The ultimate issuance is contingent upon the attainment of certain goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $4.0 million. There were approximately 46,700 performance shares awarded in February 2024. The grant date fair value of the shares awarded was $3.3 million.

Restricted Stock Units. The following table presents information regarding our available restricted stock units.

	2023		2022		2021	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Available as of January 1	33,564	$68.80	28,141	$73.16	37,482	$77.64
Granted *(a)*	21,200	$61.16	15,477	$63.70	16,251	$64.97
Awarded	(9,631)	$81.91	(7,396)	$75.55	(23,631)	$74.53
Forfeited	(1,389)	$63.46	(2,658)	$66.44	(1,961)	$74.52
Available as of December 31	43,744	$62.38	33,564	$68.80	28,141	$73.16

(a) Shares granted include accrued dividends.

There were approximately 24,300 restricted stock units granted in January 2024 for the vesting period ending in 2026. The grant date fair value of the restricted stock units granted was $1.4 million. There were approximately 11,200 restricted stock units awarded in February 2024. The grant date fair value of the shares awarded was $0.7 million.

NOTE 14. BUSINESS SEGMENTS

We present two reportable segments: Regulated Operations and ALLETE Clean Energy. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes three operating segments which consist of our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC. ALLETE Clean Energy is our business focused on developing, acquiring and operating clean and renewable energy projects. We also present Corporate and Other which includes three operating segments, New Energy, a renewable energy development company, BNI Energy, our coal mining operations in North Dakota, and ALLETE Properties, our legacy Florida real estate investment, along with our investment in Nobles 2, South Shore Energy, our non-rate regulated, Wisconsin subsidiary developing NTEC, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, land holdings in Minnesota, and earnings on cash and investments.

Year Ended December 31	2023	2022	2021
Millions			
Operating Revenue			
Residential	$165.7	$175.9	$160.8
Commercial	184.6	187.2	168.6
Municipal	33.4	40.2	52.0
Industrial	593.6	589.0	565.5
Other Power Suppliers	146.1	165.8	168.7
Other	114.9	101.2	112.3
Total Regulated Operations	1,238.3	1,259.3	1,227.9
ALLETE Clean Energy			
Long-term PSA	65.0	77.2	75.5
Sale of Wind Energy Facilities	348.4	33.5	—
Other	5.1	7.6	11.4
Total ALLETE Clean Energy	418.5	118.3	86.9
Corporate and Other			
Long-term Contract	101.2	89.2	84.4
Sale of Renewable Development Projects	92.5	73.9	—
Other	29.3	30.0	20.0
Total Corporate and Other	223.0	193.1	104.4
Total Operating Revenue	$1,879.8	$1,570.7	$1,419.2
Net Income Attributable to ALLETE *(a)*			
Regulated Operations	$147.2	$149.9	$129.1
ALLETE Clean Energy *(b)*	71.7	16.3	26.3
Corporate and Other *(c)(d)*	28.2	23.1	13.8
Total Net Income Attributable to ALLETE	$247.1	$189.3	$169.2

(a) Includes interest expense and interest income resulting from intercompany loan agreements and allocated to certain subsidiaries. The amounts are eliminated in consolidation.

(b) Net income in 2023 includes a $44.3 million after-tax gain recognized for a favorable arbitration ruling. (See Note 9. Commitments, Guarantees and Contingencies.)

(c) Net Income in 2022 includes a $8.3 million after-tax expense as a result of purchase price accounting related to projects under development at the time of acquisition and $2.7 million after-tax of transaction costs related to the acquisition of New Energy.

(d) In 2021, South Shore Energy sold a portion of its undivided ownership interest in NTEC to Basin. The closing of the transaction resulted in the recognition of an approximately $8.5 million after-tax gain which is reflected in Corporate and Other. (See Note 1. Operations and Significant Accounting Policies.)

NOTE 14. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2023	2022	2021
Millions			
Depreciation and Amortization			
Regulated Operations	$179.2	$171.9	$170.7
ALLETE Clean Energy	57.5	58.6	49.2
Corporate and Other	15.1	11.7	11.8
Total Depreciation and Amortization	$251.8	$242.2	$231.7
Interest Expense *(a)*			
Regulated Operations	$63.9	$58.1	$57.3
ALLETE Clean Energy	0.8	2.3	1.5
Corporate and Other	22.5	19.6	13.2
Eliminations	(6.4)	(4.8)	(2.9)
Total Interest Expense	$80.8	$75.2	$69.1
Equity Earnings			
Regulated Operations	$23.1	$19.3	$21.3
Corporate and Other	(1.4)	(0.6)	(1.3)
Total Equity Earnings	$21.7	$18.7	$20.0
Income Tax Expense (Benefit)			
Regulated Operations	$22.4	$(10.4)	$(16.6)
ALLETE Clean Energy	2.7	(15.4)	(16.6)
Corporate and Other	2.8	(5.4)	6.3
Total Income Tax Expense (Benefit)	$27.9	$(31.2)	$(26.9)

(a) Includes interest expense resulting from intercompany loan agreements and allocated to certain subsidiaries. The amounts are eliminated in consolidation.

As of December 31	2023	2022
Millions		
Assets		
Regulated Operations	$4,335.0	$4,291.4
ALLETE Clean Energy	1,594.1	1,873.3
Corporate and Other	727.3	680.9
Total Assets	$6,656.4	$6,845.6
Capital Expenditures		
Regulated Operations	$236.3	$158.3
ALLETE Clean Energy	(5.3)	2.2
Corporate and Other	25.0	47.6
Total Capital Expenditures	$256.0	$208.1

NOTE 15. QUARTERLY FINANCIAL DATA (UNAUDITED)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share				
2023				
Operating Revenue	$564.9	$533.4	$378.8	$402.7
Operating Income	$48.3	$53.5	$36.0	$43.1
Net Income Attributable to ALLETE	$58.2	$51.5	$85.9	$51.5
Earnings Per Share of Common Stock				
Basic	$1.02	$0.90	$1.50	$0.89
Diluted	$1.02	$0.90	$1.49	$0.89
2022				
Operating Revenue	$383.5	$373.1	$388.3	$425.8
Operating Income	$53.4	$13.7	$33.4	$33.7
Net Income Attributable to ALLETE	$66.3	$37.6	$33.7	$51.7
Earnings Per Share of Common Stock				
Basic	$1.24	$0.67	$0.59	$0.90
Diluted	$1.24	$0.67	$0.59	$0.90
2021				
Operating Revenue	$339.2	$335.6	$345.4	$399.0
Operating Income	$42.0	$28.2	$31.1	$50.0
Net Income Attributable to ALLETE	$51.8	$27.9	$27.6	$61.9
Earnings Per Share of Common Stock				
Basic	$0.99	$0.53	$0.53	$1.18
Diluted	$0.99	$0.53	$0.53	$1.18

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions		Deductions from Reserves *(a)*	Balance at End of Period
		Charged to Income	Other Charges		
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2021 Trade Accounts Receivable	$2.5	$1.2	—	$1.9	$1.8
2022 Trade Accounts Receivable	$1.8	$1.9	—	$2.1	$1.6
2023 Trade Accounts Receivable	$1.6	$1.3	—	$1.3	$1.6
Deferred Asset Valuation Allowance					
2021 Deferred Tax Assets	$69.9	$(0.9)	—	—	$69.0
2022 Deferred Tax Assets	$69.0	$(8.8)	—	—	$60.2
2023 Deferred Tax Assets	$60.2	$(2.2)	—	—	$58.0

(a) Includes uncollectible accounts written-off.

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