# Office of the Consumer Advocate

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July 31, 2024

**Via Email**

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

**Attention: Jo-Anne Galarneau**
**Executive Director and Board Secretary**

Dear Ms. Galarneau:

**Re: Newfoundland Power Inc. – 2025-2026 General Rate Application**
**Submission of the Consumer Advocate**

On December 12, 2023 Newfoundland Power submitted to the Public Utilities Board (the "Board") its 2025-2026 General Rate Application (the "GRA"). The GRA was submitted in conjunction with Newfoundland Power's 2024 Rate of Return on Rate Base Application which proposes, among other things, an average increase in customer rates of 1.5% effective July 1, 2024 and deferred cost recovery of a 2024 revenue shortfall amount of $6,722,000. The Board has not yet issued an Order on the 2024 Rate of Return on Rate Base Application.

The 2025-2026 GRA proposes that the Board approve (see cover letter to GRA):

- An average increase in Newfoundland Power's customer rates of 5.5%, with effect from July 1, 2025. Newfoundland Power claims that the rate increase is necessary for it "*to have a reasonable opportunity to earn a just and reasonable return in each of 2025 and 2026 in accordance with section 80 of the Public Utilities Act*".
- A return on equity in 2025 and 2026 of 9.85% based upon a 45% common equity ratio. Newfoundland Power is of the opinion that this represents a "*fair return on equity for Newfoundland Power in 2025 and 2026*".
- Various changes relating to regulatory accounting including:
    - Amendments to Clause II.9 of the Rate Stabilization Clause;
    - Amendments to the definition of the Demand Management Incentive Account;
    - Amendments to the definition of the Pension Capitalization Cost Deferral Account; and,
    - The amortization over the 2025 to 2027 period of: a) an estimated $1,000,000 in Consumer Advocate and Board hearing costs associated with the Application; and, b) a forecast 2024 revenue shortfall of approximately $6,722,000 and a forecast 2025 revenue shortfall of approximately $16,761,000.

The GRA has included two rounds of requests for information (RFIs) submitted to Newfoundland Power, a further round of RFIs submitted to the various experts participating in the GRA, and a hearing with cross-examination of experts and Newfoundland Power witnesses conducted during the period from June 13 to 28, 2024. The Board set a July 31, 2024 date for submissions by the parties on the GRA. This document serves as the submission of the Consumer Advocate, and is organized as follows:

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## 1. OPENING REMARKS

The GRA is a proposal by Newfoundland Power to increase its profits. Newfoundland Power proposes an across-the-board rate increase of 5.5%, and the amortization over the 2025 to 2027 period of a forecast 2024 revenue shortfall of about $6,722,000 and a forecast 2025 revenue shortfall of about $16,761,000. Newfoundland Power proposes nothing for its customers in return for the proposed revenue increase. For example, Newfoundland Power does not propose improvements in the fairness of the rate regime, rate options to provide customers a measure of control over their bills, smart meters to improve customer service and quality of supply, rate smoothing to reduce rate shock, a distribution planning standard to reduce future planning errors and ensure that all options, particularly behind-the-meter options, are given proper weighting. Newfoundland Power also fails to contain the growth in its costs. Operating expenses are growing by more than inflation and depreciation costs are rising due to the utility's high level of capital expenditures.

The GRA is nothing more than an effort by Newfoundland Power to increase the profits of its shareholder while avoiding any serious effort to bring its cost growth below the inflation rate.

Ms. Greene sums up the GRA during her cross-examination of Mr. Murray, Newfoundland Power's President and Chief Executive Officer and Ms. London, Newfoundland Power's Vice President, Finance and Chief Financial Officer.

1. (June 17, 2024 Transcript, page 107-108) Ms. Greene states with respect to the profits that would be realized by Newfoundland Power's shareholder "*And again, if we look at what the actual dollar terms are, we would see it was 48 million actual earnings per common share in*

*2023, and you are proposing in the revenue requirement that you would--it would result in 63.65 million, is that correct?*" Ms. London responds "*Yes.*"[1]

2. (June 14, 2024 Transcript, page 53) Ms. Greene asks Mr. Murray "*And if we added all of those up, we would get over 20 percent increase, and if we add on the 2.25 to come from Hydro next year on July 1, 2025 arising from rate mitigation, we're almost up to a 23 percent increase in rates for customers between where we are now and July 1, 2025. Is that correct?*" Mr. Murray responded "*Those numbers sound correct, yes.*"

3. (June 14, 2024 Transcript, page 55) Ms. Greene asks Mr. Murray if he is aware that "*in the past, the Board has considered a 10 percent increase for customers as a rate shock? Anything above 10 percent would be considered a potential rate shock?*" Mr. Murray responded that he is aware of this.

4. (June 14, 2024 Transcript, pages 68-69) Ms. Greene notes that operating costs were about $69 million in the 2023 Test Year. In the 2026 Test Year, operating costs are forecast to be $81.6 million, representing an 18% increase over 3 years. Mr. Murray does not deny this assertion.

In spite of severe rate impacts that customers are facing over the next year of close to 23%, Newfoundland Power proposes an increase in earnings per common share of over 32%. Ms. Greene sums up the Application as follows (June 14, 2024 Transcript, page 71) "*So, business as usual again*". Newfoundland Power senior management has made no attempt to mitigate the huge 23% customer rate increase and provided no direction to line management to cut costs to only those absolutely necessary to provide service. Further, Newfoundland Power proposes no programs in the GRA that would provide customers a measure of control over their electricity bills.

The remainder of this submission deals with the substantial issues of the Application as well as some other related issues of relevance to customers.

## 2. COST OF CAPITAL

### 2.1 Fair Return Standard

Determination of a fair return for Newfoundland Power is the central issue in this proceeding. The legislative framework in Newfoundland and Labrador for utility regulation provides guidance to the Board on how this is to be done. Subsection 80(1) of the *Public Utilities Act,* RSNL 1990, c. P-47 (the *"Act")* states that "*a public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board.*" In carrying out its duties under the *Act*, the Board is required by section 4 of the *EPCA, 1994* to observe the power policy of the province set out in section 3 of the *EPCA, 1994*, and to apply tests which are consistent with generally accepted sound public utility practice. Paragraph 3(a)(iii) of the *EPCA, 1994* provides that the rates to be charged for the supply of power should provide sufficient revenue to enable the utility to earn a just and reasonable return so that it is "*able to achieve and maintain a sound credit*

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[1] This is an increase of $15.65 million, or about 32.6% (June 14, 2024 Transcript, page 140).

*rating in the financial markets of the world*." Paragraph 3(b)(iii) stipulates that power should be delivered at the lowest possible cost consistent with reliable service. As in past proceedings, the Board must consider the relevant legislative provisions in its determination of the fair return for Newfoundland Power. In Order No. P.U. 43(2009), Order No. P.U. 13(2013), and Order No. P.U. 18-2016 (the most recent Order on this issue following a contested hearing), the Board stated that "*to be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital*." This statement, which reflects accepted regulatory principles, concisely captures the requirements that must be met to determine a fair return. All three requirements must be met, and no one requirement takes precedence over the other two. It is accepted that the fair return cannot be determined independently of a consideration of the utility's capital structure. The appropriate capital structure for Newfoundland Power is, therefore, also an issue in this proceeding.

## 2.2 The Legal Framework

In *ATCO Gas and Pipelines Ltd. Alberta (Energy and Utilities Board)*, 2006 SCC 4, the Supreme Court of Canada stated [citations omitted; bolding inserted]:

> 3. The business of energy and utilities is no exception to this regulatory framework. **The respondent in this case is a public utility** in Alberta which delivers natural gas. **This public utility is nothing more than a private corporation subject to certain regulatory constraints. Fundamentally, it is like any other privately held company: it obtains the necessary funding from investors through** public issues of shares in stock and **bond markets; it is the sole owner of the resources, land and other assets; it constructs plants, purchases equipment, and contracts with employees to provide the services; it realizes profits resulting from the application of the rates approved by the Alberta Energy and Utilities Board ("Board")**...That said, **one cannot ignore the important feature which makes a public utility so distinct: it must answer to a regulator. Public utilities are typically natural monopolies: technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment**... Efficiency of production is promoted under this model. However, **governments** have purported to move away from this theoretical concept and **have adopted what can only be described as a "regulated monopoly". The utility regulations exist to protect the public from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service...**
>
> **4. As in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions...**
>
> **78. ...At the risk of repeating myself, a public utility is first and foremost a private business venture which has as its goal the making of profits. This is not contrary to the legislative scheme, even though the regulatory compact modifies the normal principles of**

**economics with various restrictions explicitly provided for in the various enabling statutes…**

2.3 Newfoundland Power Being an Investor-Owned Public Utility

Newfoundland Power is a public utility that is investor-owned, the investor being a private corporation. As a private corporation, it makes business decisions with the ultimate goal of maximizing the residual benefits (i.e. profits) for its shareholders (i.e. Fortis Inc.). Newfoundland Power's income results from the application of rates approved by the Board. Those rates are significantly influenced by the rate of return on its rate base and its capital structure equity ratio. The higher the ROE (rate of return on equity) and/or the higher the equity ratio, the higher Newfoundland Power's profits can be. When cross-examined before the Board, Mr. Coyne had this to say:

*COFFEY, KC:*
*Q. Would a utility, such as Newfoundland Power, would they be incentivized to earn as much as possible, money, within the regulatory scheme?*

*MR. COYNE:*
*A. It depends, the incentives in a regulatory model would typically provide, create those incentives. In the case of Newfoundland Power specifically, they're limited, they're capped in terms of–*

*COFFEY, KC:*
*Q. Oh yeah, that's the nature of regulations.*

*MR. COYNE:*
*A. So I would say under the regulatory model, I would say that Newfoundland Power is incentivized to earn up to its cap, but beyond that, it can't maximize profits beyond that, so it's not a position to "maximize profits beyond its cap", so you can't ignore that regulatory model.*

*COFFEY, KC:*
*Q. But up to the cap, it's incentivized to maximize profit, correct?*

*MR. COYNE:*
*A. Up to its cap it's incentivized, well, it's incentivized to earn profits up to its cap would be how I would say that.*

*COFFEY, KC:*
*Q. And it's incentivized, as the shareholders to, if possible, to have the cap increased because the higher the cap, the more of a profit.*

*MR. COYNE:*
*A. I would say that's fair.*[2]

[2] June 18, 2024 Transcript (page 39, line 22 to page 41, line 6)

Members of Newfoundland Power's senior executive testified. When asked about the basis for Newfoundland Power's request to increase its ROE from 8.5% to 9.85% while keeping its 45% equity ratio, CEO Gary Murray repeatedly deferred to Concentric, so much so as to seemingly disavow any responsibility by Newfoundland Power. CFO Paige London's testimony echoed Mr. Murray's. Below are excerpts from their testimony.

*BROWNE, KC:*
*Q. But you're effectively looking to increase rates to move your profit from 48 million to 60 million, you're here looking for, to move your rate of return from 8.5 to 9.8* (sic), *a 16 percent increase and to increase your profit from 48 million to 60 million, a 25 percent increase, ...?*

*MR. MURRAY:*
*A. That's correct,* ***that is the recommendation from our cost of capital expert, Concentric Energy Advisors.***[3]

*SIMMONS, KC:*
*Q. Okay. So, no costs in operating. What about in the investment category? So, is this relevant at all to your Rate Application and the 5.5 percent that you're looking for?*

*MR. MURRAY:*
*A. It is relevant to the risk that we are exposed to in terms of, you know, the return that we expect for the risk that we take. So,* ***that is one of the elements that plays into the risk which Concentric advisors can speak to that -***

*SIMMONS, KC:*
*Q. Okay. So –*

*MR. MURRAY:*
*A. -* ***and the assessment of Newfoundland Power and our risk.***

*SIMMONS, KC:*
*Q. So, there's--so, these risks that you've identified here, they are not--there's no capital investments that's going to happen in '25 or '26 because of those risks? There's no operating expense increase? The only way this is relevant to Newfoundland Power's application is if--is in the cost of capital claim, is that right?*

*MR. MURRAY:*
*A. To the best of my knowledge, yes, that's correct.*

*SIMMONS, KC:*
*Q. Okay. And that's for Concentric to comment on?*

[3] June 13, 2024 Transcript (page 73, lines 11 to 24)

*MR. MURRAY:*
*A. That's correct.*[4]

*SIMMONS, KC:*
*Q. So once again, aside from what you told us about the long-term risks related to LIL reliability, what's different now compared to when the last GRA or even the previous two GRAs was done, that justifies the Board making a different decision that they made before which was based on substantially the same asks for return on equity and the same expert recommendation on return on equity, why should they do something different than 8.5 percent now?*

*MR. MURRAY:*
*A. You know,* ***the 9.85 recommendation is Mr. Coyne's testimony and evidence. Mr. Coyne and Concentric Advisors will be here to present their rationale on that.*** *You know, it's been long recognized the 45 percent equity by the Board, you know, due to our small size and cost flexibility and limited growth is important and the higher return on equity, you know,* ***which Concentric will speak to,*** *is looking at a fair return standard and the risk profile of Newfoundland Power to similar utilities and what is an appropriate return under the fair return standard.*

*SIMMONS, KC:*
*Q. So aren't those just all the same arguments that were made last time?*

*MR. MURRAY:*
*A. You know,* ***Mr. Coyne and Concentric is looking at what has been the change since the last time*** *and equity returns in North America have gone up since our last rate case.*

*SIMMONS, KC:*
*Q. Uh-hm.*

*MR. MURRAY:*
*A. So under the fair return standard, looking at what is a comparable return for comparable risk for Newfoundland Power.*

*SIMMONS, KC:*
*Q. Okay, so the underlying reason then for the request to increase the return on equity is that equity is more costly in the capital markets now than it was last GRA, is that the reason?*

*MR. MURRAY:*
*A.* ***Well, I'll let Concentric, you know, Energy advisor speak to that because that's their recommendation.***

[4] June 13, 2024 Transcript (page 159, line 6 to page 160, line 16)

*SIMMONS, KC:*
***Q. And from your seat as the CEO of the organization, it sounds like you are deferring to the opinion of your expert at Concentric on whether a return on equity increase is needed by Newfoundland Power and you're not offering me any other reason for that, other than the opinion of Mr. Coyne, do I have that right?***

*MR. MURRAY:*
***A. Well Concentric Energy advisors have done the comparison of Newfoundland Power to utilities of similar risks, that's the work that they've done to come up with the recommendation of the 9.85.***[5]

*GREENE, KC:*
***Q. So, we've already answered some questions about this and you deferred to Concentric, but I want to ask as CEO and President and explaining to ratepayers why you are asking for that significant increase in your ROE knowing that there was going to be in excess of 20 percent increase in customer rates by July 1, 2025, how did you, as President and CEO, satisfy yourself that it was reasonable to do that?***

*MR. MURRAY:*
*A. You know,* ***as I indicated earlier, the from Concentric advisors.*** *I mean, they look at what Newfoundland Power's risk is compared to similar utilities and based on the fair return standard, what a fair return is for Newfoundland Power and* ***that is where the recommendation comes from.***

*GREENE, KC:*
*Q. Yes, and* ***that is a recommendation of your consultant and you are deferring to the consultant and what I guess I'm suggesting is isn't there a role here for the executive at Newfoundland Power knowing that that recommendation of 9.85 and 45 percent would put you at the highest ROE, common equity, pretty much in Canada for an electrical utility, that you feel reasonable and comfortable in coming forward with it and saying, oh, that's the consultant?***

*MR. MURRAY:*
*A.* ***We take the recommendation of consultant,*** *I mean, we're not cost, coming out of cost of capital expert and* ***based on the recommendation and the fair return standard, that is the recommendation for a fair return for Newfoundland Power.***[6]

*GREENE, KC:*
*Q. Yes,* ***I was just going back to the reasonableness of total reliance on a consultant whose recommendations have not been accepted in the past and whether, as CEO, you would have some personal view as to what the appropriate profit level is to seek from customers at this point in time, as they're looking at the 20 percent increase, more than a 20 percent increase.***

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[5] June 14, 2024 Transcript (page 11, line 1 to page 13, line 17)
[6] June 14, 2024 Transcript (page 140, line 13 to page 142, line 1)

*MR. MURRAY:*
*A. You know,* ***we're relying on our cost of capital expert's recommendation.***[7]

*MR. O'BRIEN:*
*Q. What does Newfoundland Power propose as a capital structure and return on equity for 2025 and 2026?*

*MS. LONDON:*
*A.* ***Based on the expert opinion of Concentric, Newfoundland Power is proposing the continuation of our longstanding capital structure of 45 percent common equity and an increase in the return on equity to 9.85 percent.*** *These proposals are consistent with the fair return standard.*[8]

*GREENE, KC:*
*Q. So, if we look at the request Newfoundland Power has made to increase from 8.5 percent to 9.85 percent, that equals about 1.6 percent of the 5.5 percent that you are proposing in the current application, is that correct?*

*MS. LONDON:*
*A. Yes.*

*GREENE, KC:*
*Q. And again, if we look at what the actual dollar terms are, we would see it was 48 million actual earnings per common share in 2023, and you are proposing in the revenue requirement that you would--it would result in 63.65 million, is that correct? If you like we could go to Exhibit 3 and 5.*

*MS. LONDON:*
*A. Yes.*

*GREENE, KC:*
*Q. Okay. So, that's over 30 percent increase in your earnings per share that you're looking for in this application, almost 33 percent, from 48 million to 63.65 in three years.*

*MS. LONDON:*
*A. Subject to check on the calculation, yes.*

*GREENE, KC:*
***Q. What was your role as the VP Finance in putting forward this proposal to the Board?***

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[7] June 14, 2024 Transcript (page 144, line22 to page 145, line 9)
[8] June 14, 2024 Transcript (page 163, line 1 to line 12)

*MS. LONDON:*
*A. **We engaged Concentric as a cost of capital of expert to determine what a fair return proposal for Newfoundland Power would be. So, Concentric would have done their analysis** of using their various modelling and techniques, as well as they performed a relative risk assessment, **and they would have reported back a range and a mid-point of preliminary recommendations for a fair return for Newfoundland Power. We reviewed that return** and then we--that proposal, **and then we would have put forth the recommendation to maintain 45 percent equity and a proposed ROE of 9.85 percent.***

*GREENE, KC:*
*Q. **So, in your role of Vice President Finance, you agree that this is the correct proposal, or that reflects the risk of Newfoundland Power, is that correct?***

*MS. LONDON:*
*A. **Yes, it is***

*GREENE, KC:*
*Q. **Do you agree that Newfoundland Power has above average business risk compared to other electrical utilities in Canada?***

*MS. LONDON:*
*A. **Practically Newfoundland Power relies on Concentric to do that relative business risk assessment, and that is their finding. Newfoundland Power and our executive team specifically, we can talk about our business risks, our profile, generally, but we do rely on Concentric for that relative risk assessment..***[9]

*GREENE, KC:*
*Q. Okay. And **other than Muskrat Falls**, which we've already talked about, **are there any other risk factors you would like to explain to the Board that affect your assessment that you're above average risk?***

*MS. LONDON:*
*A. **The assessment or conclusion of above average risk is on the basis on Concentric,** just to clarify that, **but the overall risk profile for Newfoundland Power, as we have identified and outlined in our evidence**—I think that we have talked about, you know, **many of the pieces of those. Cost flexibility I did speak to earlier** as well....*[10]

*GREENE, KC:*
*Q. So, **now I'd like to go to how overall the ROE and the capital structure of Newfoundland Power compares to other utilities in Canada**, and here if we go to Dr.* (sic.) *Coyne's rebuttal evidence, page ten. And when look at this* ***Figure 1, it's very helpful because it talks about the weighted ROE for Canadian utilities*** *and we look at the equity in the capital structure, whether it's 45 percent for you, times the approved*

[9] June 17, 2024 Transcript (page 107, line 8 to page 109, line 24)
[10] June 17, 2024 Transcript (page 120, line 16 to line 24)

*ROE of 8.5 percent. So, if we look at the grey bar that's kind of three-quarters of the way over, and we see at the bottom, Newfoundland Power. So, here we see the grey bar, the current – where you currently are,* ***you're about 3.8 weighted ROE, which is better than Fortis Alberta, Hydro One, Nova Scotia Power, other Ontario Electric Distributors, Maritime Electric. So, right now, you're more than halfway up the pack, the group. Then we look at where your recommendation brings us, which is the green bar, Concentric's recommendation. That will put you the highest of any electrical utility in Canada. So,*** *I would say,* ***if your recommendation is approved, not only would you be a comparable risk, you would be probably the best electrical utility to invest in.*** *So, in looking at this figure, which as I said I find helpful to look at another one of the requirements of the fair return standard, which is the comparable investment.* ***Can you explain or in your opinion, the current ROE and the current 45 percent does provide Newfoundland Power with meeting the requirement that investment in Newfoundland Power be comparable to other electrical utilities of similar risk. Is that correct?***

*MS. LONDON:*
*A.* ***When it comes to the comparability and risk, that's something that I will have to defer to Concentric.*** *The comment that I would make is Newfoundland Power's weighted return on equity is reflective of our risk profile and that is part and parcel of our 45 percent common equity that's been in place for a long period of time.*[11]

*GREENE, KC:*
*Q. The last time that Mr. Coyne provided evidence and Newfoundland Power sought an increased ROE for the last 22 general rate applications, Mr. Coyne and Newfoundland Power asked for approval of 9.8 percent. Is that correct?*

*MS. LONDON:*
*A. Yes, it is.*

*GREENE, KC: Q.* ***So, if cost of capital has gone up and the recommendation now is only 9.85, is that the amount of the increase in the cost of capital we're talking about, less than five basis points?***

*MS. LONDON:*
*A.* ***In terms of the difference in Concentric's recommendations based on their model, I think that's a question that they would be able to respond to.***[12]

In effect, Newfoundland Power's position concerning its request for a 9.85% ROE and 45% equity ratio is: "We are not responsible. We defer to Concentric." However, Newfoundland Power chose to pursue its request for a 16% higher ROE while maintaining such a high equity ratio as to be a Canadian outlier.

[11] June 17, 2024 Transcript (page 139, line 24 to page 141, line 23)
[12] June 17, 2024 Transcript (page 143, line 16 to page 144, line 10)

Newfoundland Power, upon receiving Concentric's report, could have sought another opinion concerning its cost of capital. It chose not to, presumably because the recommendation for a 9.85% ROE and 45% equity ratio accorded with Newfoundland Power's goal of increasing its weighted ROE and thereby increasing the benefits (i.e. profit) to its shareholder.

### 2.4 Risk and Capital Structure

#### 2.4.1 Canada's Fair Return Standard Involves Comparative Investment in Securities

Evidence was filed concerning the fair return standard and how it would in the circumstances of this application best be met.

Dr. Booth's direct evidence states:

> *In terms of financial charges, the decision in Northwestern Utilities vs. City of Edmonton (1929) stated that a utility's rates should consider changed conditions in the money market, where a fair rate of return was further confirmed in the BC Electric decision. This decision adopted Mr. Justice Lamont's definition of a fair rate of return put forward in Northwestern Utilities,*
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> > *"that the company will be allowed as large a return on the capital invested in the enterprise as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."*
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> *This definition is referred to as a market opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility are given an opportunity to earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. In this way the fair rate of return in Canada is conventionally applied as a market rate applied to the book value of the utility's assets.*
>
> *The only qualification is that in the overall utility cost of capital the cost of debt is not the current market opportunity cost, but the embedded debt cost. In this way the debt cost is treated like the acquisition of a capital asset and prudently acquired, the actual debt cost is included in rates. The only use in Canada of determining the overall utility cost as an opportunity cost is that of the CER which used the after tax weighted average cost of capital (ATWACC). However, this introduces excessive complexity and unnecessary technical problems.*
>
> *Regardless to any modern financial economist Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a market required or expected rate of return on the book value of equity. This is the rate set in the capital or money market as conditions change.*[13]

[13] April 2024 Written Evidence of Dr. Laurence Booth (page 7, line 3 to page 8, line 3)

Concentric's direct evidence states:

> *The principles surrounding the concept of a "fair return" for a regulated company were first established by the Supreme Court of Canada in Northwestern Utilities v. City of Edmonton (1929) S.C.R. 186 ("Northwestern"), where the Supreme Court of Canada found:*
>
>> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*

However, in responding to Dr. Booth's direct evidence, Concentric states:

>> *Further, his ROE recommendation would not provide the Company with a return that is comparable to those of other companies with similar business and financial risk. On that basis, Dr. Booth's ROE recommendations does not satisfy the Fair Return Standard.*[14]

In oral testimony, Dr. Booth identified a fallacy in Concentric's Rebuttal Testimony, which fallacy was repeated in Mr. Coyne's oral testimony.

> *DR. BOOTH:*
> *A. And I hope Mr. O'Brien doesn't object too much to some of my comments, but this is a critical issue: What is the legal standard in Canada and the United States? And several times I heard Mr. Coyne yesterday refer to alternative investments and alternative allowed rates of return. That is not the standard in Canada. The standard in Canada is that of Mr. Justice Lamont and the definition states, "the company will be allowed as large a return on the capital invested in the enterprise as it would receive if it were investing the same amount in other securities possessing and attractiveness, stability and certainty equal to that of the company's enterprise." So, the front and foremost is risk, and I'll be talking about risk. But there's also something in there which is relevant to Canada, but doesn't seem to be as directly relevant in the United States. That is it specifically refers to securities. It doesn't say investments. It doesn't say alternative business investments or rates of return that firms earn elsewhere. It refers to securities, and there's a big difference between the rate of return on a security and the rate of return earned on a business...*[15]
>
> *DR. BOOTH:*
> *A. I'm just making a point about the definition of the legal standard...the comment is simply that the basic definition of a fair return in Canada is based upon the securities, not on the book value of the investment. The price paid by KKR for the Labrador Island Link, all I'm saying is if it a premium -- and I don't know whether it's a premium. All*

[14] May 28, 2024 Concentric Written Rebuttal Testimony May 28, 2024 (page 2, lines 21 to 24)
[15] June 19, 2024 Transcript (page 144, line 24 to page 146, line 1)

*I'm doing is relying upon the information that was put before the Board yesterday. If it is a premium, it means that the 8.5 percent rate of return is attractive. That is my expert opinion. That would be the opinion of any undergraduate in finance. That is not, I would suggest, a contentious issue. But the point is simply what is the legal standard of a fair return. And if you listen to Mr. Coyne yesterday and today, he consistently said fair return standard. He consistently said fails to meet the fair return standard. And here we have an objective example directly relevant to this hearing that indicates what the fair return is. So, that would be my computation.*

*CHAIRMAN:*
*Q. I think what Mr. Booth has done with regard to a simple computation of the press release purchase value relative to the book value presented in the press release probably wouldn't be a surprise with regard to the purchase price being in excess, which would indicate the return being lower. So, I'm struggling with that being a challenging matter to ask questions on. The issue itself was brought up yesterday and so that is on the record. I think if you – Mr. O'Brien if you want to talk more about this, I think you'll have time to ask questions on it tomorrow.*[16]

*DR. BOOTH:*
*A. ...So, then the question is, the legal standard is not just a market based opportunity cost on securities, but changes in the money market. What's going on in the capital markets? What's changed since the last litigated hearing in 2016? The core of that is the money market, the overnight rate, and that's--Mr. Coyne didn't mention it.*[17]

*MR. O'BRIEN:*
*Q. Okay. So, if we can pull up Concentric direct, page five, the fair return standard, there's a section there that's outlined, and lines 1 to 10, Concentric goes through the principle surrounding the concept of a fair return standard and cites the Northwest Utilities case, the Supreme Court of Canada case. So, they cite that fair return standard. Is that an accurate depiction of the fair return standard in Canada?*

*DR. BOOTH:*
*A. I think he uses – yes, that's just Mr. Justice Lamont's definition.*

*MR. O'BRIEN:*
*Q. Yeah, okay.*

*DR. BOOTH:*
*A. But go to his rebuttal testimony...And I've seen American witnesses that in, but American witnesses are coming from America, and if you read Mr. Coyne's rebuttal testimony, and I don't know whether he did this or Mr. Trogonoski did, and he said this yesterday or perhaps it was the day before, page two. "Further, his ROE*

[16] June 19, 2024 Transcript (page 152, line 3 to page 153, line 19)
[17] June 19, 2024 Transcript (page 174, line 18 to page 175, line 2)

*recommendations would not provide the company with a return that is comparable to those of other companies with similar business and financial risk."*

*MR. O'BRIEN:*
*Q. Okay.*

*DR. BOOTH:*
*A. Other companies. That is not the fair return standard... So, let's read this and this is what he said yesterday. So, it's what you might put as bulletproof sort of stuff in your testimony and there's what you believe. This is what he said in his rebuttal testimony, and it's what he said in testimony yesterday. "Further, his ROE recommendation would not provide the company with a return that is comparable to those of other companies with similar business and financial risk." That's a return on the companies. "On that basis, Dr. Booth's ROE recommendation does not satisfy the fair return standard." And I'll be honest, every time – and he said that so many times in the past, that is incorrect. The fair return standard is Mr. Justice Lamont's definition. It's the fair return not on the companies, not on their book value, their investment. It's the return on the securities...It is the required return the investor has. It's not the rate of return on other companies. That is the fair return standard. And the Alberta Utilities Commission has recognized this. It's a market opportunity cost applied through a book value investments, and that's what I've recommended.*

*MR. O'BRIEN:*
*Q. Okay. And I wanted that clarification. So, I just wanted to make sure. In terms of what the fair return standard includes, would you accept the premise that it includes the comparable investment sort of piece?*

*DR. BOOTH:*
*A. It includes comparable, return on comparable security.*

*MR. O'BRIEN:*
*Q. Right, okay, securities.*

*DR. BOOTH:*
*A. It does not include the allowed returns on other companies.*

*MR. O'BRIEN:*
*Q. No, but the comparable investment on that, comparable security, would you accept that?*

*DR. BOOTH:*
*A. That's right. See, the problem, Mr. O'Brien, is investments is an illusive* (sic) *term. Securities is not.*

*MR. O'BRIEN:*
*Q. Okay.*

*DR. BOOTH:*
*A. Securities are an investment. The rate of return on book value is an investment. So, in Canada, and I'll be honest when I say I've been looking at this. I looked at the US standards and this part has been part of my testimony for probably 30 years. The Hope standard, the Bluefield standard in the United States does not refer to securities. In Canada, it's explicitly referring to securities and explicitly referring to changes in the money market, which we now understand as the capital market. So, whether that's a substandard (unintelligible) between US and Canada, I don't know. But when Mr. Coyne starts talking about, as he says in his rebuttal – now, he can say he really meant something else; it's badly worded, which I would accept, but it is the legal standard in Canada that it's a security market issue. It's what investors in the security market want is their discount rate, and that's what I estimate.*

*MR. O'BRIEN:*
*Q. Okay. So, it's a comparable security investment or -*

*DR. BOOTH:*
*A: It's a comparative investment in securities.*[18]

2.4.2 Macroeconomic and Money Market Conditions in Canada and the U.S.

A fair return on equity is to be determined in the context of economic and capital market conditions.

James Coyne and John Trogonoski, collectively "Concentric", are the cost of capital witnesses for Newfoundland Power. They wrote this about economic and capital market conditions.

> *There has been a fundamental shift in capital market conditions since 2021, and the cost of capital (along with other input costs, including labor) is higher for all companies, including utilities. This shift has occurred in large part because the extended period of declining interest rates (which began in 1982 and which accelerated in the years after the financial crisis of 2008-2009) and low inflation has come to an end. Interest rates on government and corporate utility bonds reached all-time lows in 2020 before rebounding to levels in August 2023 that are 156 to 215 basis points higher than those in March 2021 (the date of the analysis in our report for Newfoundland Power's previous GRA). The future path of the costs of debt and equity will be influenced by the path of an uncertain economy and persistently higher inflation. In general, the low capital cost and low inflation environment of the past two decades has yielded to new economic circumstances requiring the upward repricing of capital, labor, and materials to reflect new market realities...*[19]

[18] June 20, 2024 Transcript (page 61, line 25 to page 62, line 16; page 64, line 1 to page 64, line 17; page 65, line 25 to page 66, line 20; page 66, line 23 to page 69, line 9)
[19] November 7, 2023 Concentric Cost of Capital Report (page 28, line 10 to line 20)

Nevertheless, when answering questions put by Board Counsel relating to the automatic adjustment formula, Mr. Coyne unprompted says:

> *...I think capital markets are more stable than they were back during the COVID period...*[20]

Dr. Laurence Booth, the Consumer Advocate's cost of capital expert, wrote the following about economic and capital market conditions.

> *Because the legal standard for a fair rate of return in Canada stemmed from changed conditions in the money market, where we would now understand the money market to mean the capital market. Also, conventional practice is to base the fair ROE on the forecast long term Canada (LTC) bond yield...*
>
> *As indicated above, the bond market has been heavily influenced by the actions of central banks, the rush to safety during the Covid-19 pandemic, and the subsequent recovery. It is useful, therefore, to look at broader measures of the state of the financial system. In the U.S, the Federal Reserve Bank of Kansas City has developed the Kansas City "Financial Stress" Index (KCFSI) which is graphed below. This index is designed to capture a variety of financial indicators in addition to the spreads in the money and bond markets. The additional indicators include the stock market volatility index, the state of bank share prices, and the behaviour of stock and bond returns.*
>
> *When the KCFSI is above 0, it indicates that capital markets are under stress and that access to markets is "tougher than normal." Similarly, when it is below 0, it indicates relatively easy or "stress-free" capital market conditions.*
>
> *The value of the KCFSI is simply that it captures in one number the impact of a variety of capital market indicators. The major insight of the KCFSI is that it emphasizes the enormous pressure in the U.S. financial system during the financial crisis in 2008/09, and to a lesser extent the Covid-19 pandemic. Unlike the Internet Bubble and crash in 2001, which also increased "stress", the 2008/09 crisis struck at the very core of the U.S. financial system, the banking system, while the Covid-19 pandemic struck everywhere. Here liquidity, or the ability to trade securities at close to their true market value, dried up in many parts of the U.S. capital market, and the U.S. Government had to intervene on a massive scale. Since the financial crisis, financial market conditions have been relatively easy, except for the impact of the Covid-19 pandemic in 2020. However, the tough market conditions of March and April 2020 quickly subsided. Currently, financial market conditions are close to normal as the KCFSI is tracking slightly below 0.*
>
> *The work by the Kansas City Fed followed pioneering work done by researchers at the Bank. However, the Bank now prefers to rely on alternative measures, one of the most important of which I see as being the Bank's survey of senior lending officers. The following graph shows the results up to the Bank's latest survey (2023Q4) that reflects*

[20] June 19, 2024 Transcript (page 125, line 18 to line 20)

*both the pricing and the availability of credit, where the lower the value the easier the credit market. Lending conditions were particularly easy until the Bank started to increase the overnight rate in 2022. In response to the increasing fear of insolvencies, banks started to restrict credit and charge higher fees. This process peaked in 2023Q3 as L TC bond yields peaked. Since then, pricing and availability have both returned to slightly above normal levels, and I would expect this trend to continue.*

*A final indicator is the CBOE volatility index, sometimes misleading called the fear index. The graph below [omitted] shows the index back to 1990. Similar to the other indexes, we can clearly see the impact of the U.S. financial crisis when the VIX went from its normal value of just under 20% up to almost 80%. Further, we can see the impact of Covid-19 when it again jumped to 85% on March 18, 2020, only slightly lower than the peak of 89.5% reached on October 24, 2008. However, the VIX is currently at 13.01 % in the final week of March 2024, which is significantly lower than the long term average, indicating optimism in the equity markets and "no fear".*

*The results of the Bank's surveys, credit spreads, the VIX and the KCSFI show that overall business sentiment is approximately normal, with a recovery from concerns in 2023Q4 that the Bank did not have inflation under control. Instead, there is now confidence that inflation will return to the Bank's 2% target by the end of 2024, or 2025 at the latest, and with it a decline in the overnight interest rate.*

*However, these are slightly backward looking indicators, whereas the stock market is a forward looking indicator. The following graph shows the performance of the TSX since 1956 with an added trend line. It is a log-linear graph, so the slope shows the growth from one year to the next, with the trend line the average growth rate. At the end of March 2024, the TSX hit an all time high of 22,167.00. This is marginally below the trend line fit over the entire period, where the flattening indicates the impact of lower inflation and nominal returns. However, as a leading indicator the TSX is not showing any particular concern.*

*In 2016 the Canadian economy had stalled mainly due to a slowdown in China that affected resource prices and Western Canada. As a result, I felt we were still "a couple of years" away from the peak in the business cycle. This had been reflected in a weakening equity market over the prior year and higher volatility. In debt markets the U.S. Fed had stopped its bond buying program, but the Bank of Japan and the European Central Bank had not. As a result I was contrasting the situation as one where the taps had been turned off, but the bath was still full of a massive amount of liquidity. Consequently, interest rates were much lower than they would have been but for the massive central bank purchases. At the time of my testimony (January 29, 2016), the LTC yield was 2.05%, but by looking at preferred share spreads it was my judgment that L TC bond yields had been depressed by 1.30%. In addition I added a 0.45% credit spread adjustment because the A spread was 1.91 %. So I effectively regarded the base LTC interest rate as 3.8% (2.05+ 1.3+0.45).*

> *This was the same judgment I had in 2012, and I have continued with this until the current time when interest rates have increased toward more normal levels. Currently we are at a different stage in the business cycle, where equity markets are roaring rather than weakening, and where all the standard measures, such as credit spreads, the volatility index, etc., indicate firmer, not weaker, markets. In 2016 I commented:*
>
> > *"It is often said that a broken clock is right twice a day. Similarly, although the signals are very similar, we are in the afternoon rather than the morning of the day which is to say we are in the later stages of the business cycle compared to 2011."*
>
> *This is the case today, except in reverse; we are back to the morning rather than the afternoon of the business cycle, and there is more optimism toward the future.*[21]

[graphs omitted from excerpt]

### 2.5 Newfoundland Power's Risk Profile

#### 2.5.1 Perspectives on Newfoundland Power's Risk

Newfoundland Power's risk profile is relevant for the Board's consideration of both the company's capital structure and its allowed rate of return.

In 2016, Newfoundland Power for the first time took the position before the Board that it was an above average risk Canadian utility. Concentric herein maintains that position.

> *Concentric concludes that Newfoundland Power has above average business risk compared to [five] other Canadian [investor-owned] electric utilities. In particular, factors contributing to this higher risk profile include Newfoundland Power's small size, dependence on one supplier, weaker macroeconomic and demographic trends in the province as compared to the remainder of Canada, and weather and storm-related risk. While the regulatory framework in Newfoundland and Labrador is generally supportive of maintaining credit quality, there are certain aspects of the operating environment where Newfoundland Power has higher business risk than other Canadian investor owned electric utilities. Further, Newfoundland Power has more power supply risk than other Canadian investor-owned electric utilities due to the cost of the Muskrat Falls project combined with additional costs associated with bulk electricity supply on the island portion of Newfoundland and Labrador that were previously not anticipated.*[22]

Concentric also compares Newfoundland Power to a proxy group of ten U.S. electric utility holding companies on six factors it characterizes as "short term risks" (regulated generation risk; fuel and purchased power cost risk; volume/demand risk; capital cost recovery risk; rate regulation and earnings sharing; and operating cost recovery mechanisms). Concentric finds that Newfoundland Power has higher long-term business risk than the U.S. electric proxy group companies because of unfavorable demographic trends, provincial macroeconomic growth being projected to be weak over

[21] April 2024 Written Evidence of Dr. Laurence Booth (page 6, line 4 to line 7; page 31, line 16 to page 36, line 10)

[22] November 7, 2023 Concentric Cost of Capital Report (page 78, line 3 to line 13)

the medium to long term, and its service territory being exposed to severe winter weather conditions. Concentric concedes that Newfoundland Power has similar business risk to the U.S. proxy group on most factors that affect short and intermediate term variability of earnings and cash flows, and also acknowledges that it does not suffer from a disadvantage that most U.S. proxy group companies do, namely owning significant regulated generation assets. However, Concentric notes Newfoundland Power's reliance on a single source of electric supply and that there are challenges associated with integration of the Muskrat Falls project. Concentric maintains that:

> *On balance, Newfoundland Power's business risk is somewhat higher than the operating companies in the U.S. Electric utility proxy group that would cause an investor to assign a higher risk profile to Newfoundland Power.*[23]

While Gary Murray, President and Chief Executive Officer of Newfoundland Power, did testify that he personally agrees with Concentric's assessment that Newfoundland Power is an above average risk Canadian utility, Vice-President of Finance Paige London chose not to express her own view, and instead simply deferred to Concentric.

> *GREENE, KC:*
> *Q. Do you agree that Newfoundland Power has above average business risk compared to other electrical utilities in Canada?*
>
> *MS. LONDON:*
> *A. Practically Newfoundland Power relies on Concentric to do that relative business risk assessment, and that is their finding. Newfoundland Power and our executive team specifically, we can talk about our business risks, our profile, generally, but we do rely on Concentric for that relative risk assessment.*
>
> *GREENE, KC:*
> *Q. The Board determined in 2016 that Newfoundland Power was an average risk utility, is that correct?*
>
> *MS. LONDON:*
> *A. Yes.*
>
> *GREENE, KC:*
> *Q. I believe the evidence also demonstrates there has been no significant change, or material change, in the business risk of Newfoundland Power since the last rate case when 8.5 percent ROE and 45 percent equity was approved by the Board, is that correct?*
>
> *MS. LONDON:*
> *A. Yes.*

[23] November 7, 2023 Concentric Cost of Capital Report (page 82, line 28 to line 30)

*GREENE, KC:*
*Q. So, if the Board determined before that Newfoundland Power was an average risk Canadian utility, how would you explain the position that you believe you're above average risk? The Board got it wrong, or has--if there's been no material change?*

*MS. LONDON:*
*A. Ultimately I wouldn't say the Board got it wrong. In 2016 and 2017 the Board made the determination that they viewed Newfoundland Power as average risk utility and at that time the Board maintained Newfoundland Power's 45 percent equity as fair and reasonable with the risk profile, acknowledging risks associated with both the Provincial economy and Muskrat Falls at that time.* ***Newfoundland Power's view is that our risks have not materially changed overall since that time period.*** *So, in that regard I do think it's appropriate that the Board maintain the 45 percent equity consistent with the previous determination...*[24]

*MS. LONDON:*
*A. The assessment or conclusion of above average risk is on the basis on Concentric, just to clarify that...*[25]

In Dr. Booth's opinion, Newfoundland Power is presently a typical low risk Canadian T & D electric utility. In his written evidence, Dr. Booth explains why Newfoundland Power has low business risk.

*Newfoundland Power's business risk has not increased since 2009. If anything, it has decreased since the competitive threat from fossil fuels has decreased. I still regard it as an average business risk Canadian utility with lower-than-average financial risk. In particular, residential electricity costs are not as high as in other Canadian jurisdictions, let alone in large US cities such as New York. Given the monopolistic power of Newfoundland Power (NP), I see very little, if any, long run stranded asset risk. Moreover, any such risk would first have to materialise as an inability of NP to earn its allowed Return on Equity (ROE), and there is no evidence of this. Consequently, although ratepayers are naturally concerned about a possible price spike in the short term, as the cost of Muskrat Falls energy is passed through, I do not see this as a material threat to NP or a significant increase in its business risk.*

*Similar to the NEB, I have traditionally viewed business risk as having a short and long run dimension. On short term risk I have looked at the ability of the utility to earn its allowed ROE since this reflects the impact of regulatory protection and the allowed deferral accounts (footnote 81: In almost 40 years of looking at regulated utilities' business risk, I have never once seen a witness presented by the utility look at the ability of the utility to earn its allowed ROE. Instead, they tend to focus on generalities and a subjective assessment without any attempt to translate this into a quantitative manner to uncertainty in the earned ROE.)...*

[24] June 17, 2024 Transcript (page 109, line 12 to page 11, line 14)
[25] June 17, 2024 Transcript (page 120, line 16 to line 19)

*NP has been allowed a band around its rate of return that translates into approximately +/- 0.40% on its ROE. The graph indicates that NP has consistently earned its allowed ROE with an average "excess" of 0.25% over this very long period. However, between 1990 and 1995 it underearned in five years mainly due to severe weather and a reassessment by CRA. Since then, NP has not under earned in a single year, and since 1995 its over earning has averaged 0.43% with the CRA reassessment in the early 2000's accounting for a significant amount of the overearning in those years. Excluding those years, since 2003 NP has still over earned by 0.30%, or near the top of the 0.40% band.*

*In a dictionary sense, risk is the probability of incurring harm. On the basis of its demonstrated ability at earning its allowed ROE, NP has not suffered any risk whatsoever. In fact, what risk it has suffered has not stemmed from its operations as much as its relations with CRA. More to the point, NP has consistently been allowed a risk premium. In its current 8.5% allowed ROE, the Board included a 6.7% premium over the 1.8% average LTC yield in 2016. This is a bit misleading due to the abnormally low LTC yields at that time. However, the fact is it is not risk when you only earn more than the risk-free rate, regardless of whether or not there is any variability in that return. In other words, if someone guarantees that you will always earn more than the long Canada bond yield, then you cannot be riskier than the long Canada bond!...*

*I would judge these risks to have decreased since the last litigated hearing in 2016. The main reason being that the alternative fuels used to compete with NP are carbon based such as heating oil. As of April 1 2024, there is an additional $15 a tonne of carbon taxes to reach $80, on its way to a forecast $150. This increase reflects the Government of Canada's determination to reduce carbon pollution. Currently electricity has a 10-15% advantage over fuel oil, and the penetration of subsidy supported heat pumps will only increase this in tandem with increased carbon charges on fuel oil. Given NP's monopoly position in distributing electricity in Newfoundland, it is difficult to see how its risk has not gone down...*

*In my judgement, there has been a material decrease in NP' s business risk since 2016, and any rate shock from higher electricity costs should be considered relative to the costs of alternative fuels and rates elsewhere...*

*Most [other factors raised by NP and its witnesses] have not changed in any material sense, but two things are important to consider: the impact of generation risk and the "small size" of NP.*

*In terms of size, NP constantly claims that it is a small utility, a judgment that depends entirely on the reference utilities. NP has more customers than all of Fortis' Canadian electricity operations except Fortis Alberta, which has 592,000. NP is larger than FortisBC Electric, which has 191,000, Maritime Electric which has 89,000, and Fortis Ontario, which has 69,000. NP is small only relative to Fortis US operations, and yet size alone does not mean more risk and more common equity, since FortisBC Electric is allowed 41 % common equity, Maritime Electric and Fortis Ontario are allowed 40%, and Fortis Alberta is allowed 37%. In comparison, NP's 45% common equity is clearly* *an outlier for a relatively large Canadian electricity distributor in the Fortis family...Note that NP's generation is minimal. In contrast, Fortis BC Electric, the former West Kootenay Power, has 32% of peak demand from its own generation units, Maritime Electric has 25%, and Fortis Ontario has 2%. I do not regard any of these as a significant risk factor in Canada, but generation can be important for some Canadian utilities in the comparison group...*

*It is not so much the generation itself as the* ***type of generation****. Below is the amount of generation in each of Mr. Coyne and Mr. Trogonoski's U.S. sample provided in answer to CA-10 NP-193. Of importance is that every one of the utilities except Eversource has internal generation, that is, they are not pure Transmission and Distribution (T&D) utilities, but are instead integrated utilities with generation, transmission and distribution. I regard NP as a pure T&D utility. What is more, six of the referenced U.S. utilities derive a large amount of their power from nuclear generation...*

*The Concentric witnesses argue that given NP's reliance on Newfoundland Hydro, this 'sole supplier risk' offsets NP's lack of significant generation assets. However, both Hydro Quebec Distribution and Hydro Quebec Transmission in 2013 relied 100% on Hydro Quebec generation when the witnesses reduced the rate of return from U.S. electric utilities to apply to HQD and HQT...*

*Whatever short term business risk NP faces is removed by its extensive use of deferral accounts as reflected in its consistent ability to over-earn its allowed ROE. Its long term risks have undoubtedly reduced as society has become more concerned about climate change and the burning of fossil fuels. This reduces any lingering competitive risk from fuel oil that may have resulted in fuel switching in the past. Further, although ratepayers should prepare for some possible rate shock in electricity prices, I do not see a realistic alternative or a magnitude of electricity price increases that comes close to prices in other major cities in Canada and the U.S. In this case I judge NP as being of lower risk than in the past, and as low if not lower risk than the other electricity utilities in Canada, all of which have lower allowed common equity ratios...*

*I see no objective reason why NP should have 45% common equity. In view of the potential of higher electricity prices on final completion of supply from Muskrat Falls, I do not think NP's rate payers should also be asked to pay the higher costs of an additional 5% common equity component that is not needed for a good investment grade bond rating. In 2016, I was concerned about a sudden change in the common equity ratio and suggested that instead the Board deem the 5% preferred share component the same way that the Regie does for Energir, the old Gaz Metro, where they have traditionally allowed 37.5% common and 7.5% preferred shares. If the Board is ultra conservative, it could do this in a staged manner over the next five years with 1% a year. Further, in PUB-7 (1996-97) when the Board set NP's common equity range at 40-45%, it also set the preferred share component at 3-6%. So my recommendation is consistent with past decisions of the Board.*

> *My recommendation is to replace a 5% common share component with preferred shares as an interim solution, and replace them with debt if there is in fact rate shock from higher electricity prices. The preferred share component can be deemed at the cost of Fortis' preferred shares, and NP can be asked to provide evidence on the cost of Fortis preferred share perpetual series F and J, which currently have yields of about 6%. Since both are after tax costs, this translates to an 8.57% pre-tax cost compared to NP's 8.5% allowed ROE, or about 12.14% pre-tax, for a reduction in the revenue requirement of about 3.5% for every dollar of rate base financed with the deemed preferred shares rather than common equity. This would be a half-way house to refinancing with debt, which at the pre-tax embedded debt cost of 5.11 % has a 7.0% benefit.*[26]

Testifying before the Board, Dr. Booth said this about Newfoundland Power being minimal risk.

> *I can see nothing in Newfoundland Power's history that indicates that it's any riskier than any of the other T&D utilities in Canada...*
>
> So, *I'm not saying the stranded asset risk is immaterial. It's very important for certain types of utilities. I don't see it as important for Newfoundland Power...*
>
> *MR. O'BRIEN:*
> *Q. So, there's a couple of points I want to raise with you on that. So, first of all, your opinion on risk hasn't changed all the way along in terms of Newfoundland Power. You're assessment--your assessment of Newfoundland Power as having an average business risk, and having a less than average financial risk, that hasn't changed over time.*
>
> *DR. BOOTH:*
> *A. That hasn't changed -*
>
> *MR. O'BRIEN:*
> *Q. Right.*
>
> *DR. BOOTH:*
> *A. - but as I indicated, I've never seen a utility in Canada where the regulator doesn't protect the utility, which is to say when I look--the first thing I do in any hearing is say, give me the allowed return versus the actual return going back as long as you got data so we can actually see what the short-term risk is, and Newfoundland Power is absolutely no different from any of the other Canadian utilities...*
>
> *DR. BOOTH:*
> *...So, when you look at this, has anything changed since 2016? I would say a huge amount has changed since 2016. Not in terms of the short run risk, but in terms of the*

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[26] April 2024 Evidence of Dr. Laurence Booth (page 1, line 2 to line 11; page 96, line 4 to line 6; page 96, line 9 to page 97, line 11; page 98 , line 23 to page 99, line 2; page 100, line 14 to page 102, line 14; page 103, line 23 to page 104, line 13; page 112, line 21 to page 113, line 17)

*long run risk. I would say that the stranded asset risk attached to Newfoundland Power is gone from being negligible to less than negligible. How is that significant? I can't think of any alternative to electricity in the—over the future test years in Newfoundland. Whereas in 2016 and earlier we could think about home heating oil, and this is--this is a company that doesn't serve industrial users, it serves--it serves residential and commercial with a little bit of streetlights...*

*Which is why I said in the recommendation if the Board lays down a marker, 40 to 45 percent going back to '96, '97, I'd be happy if the Board does that and then we get some clearance on Muskrat Falls and rate mitigation, then the Board can revisit this and decide, well is its decision of the business risk hasn't changed still valid...*

*But the fact that they earn their allowed ROE should be used by the Board to assess how good a job they're doing in transferring the risk from the utility to the ratepayers, which is what all these deferral accounts do. And that's part of the regulatory protection and the regulatory compact in Canada... when I first testified I used to see the company witnesses coming in talking about business risk, financial risk, regulatory risk. There is no regulatory risk. It's regulatory protection in Canada.*[27]

Dr. Booth expressed his views on the current Canadian economy.

*In terms of the economy... My overall assessment was that in 2016 we were suffering from the effects of a short technical recession caused by low commodity prices and a slow down in China. This mainly affected Western Canada, but we were close to the low point of the business cycle. In contrast, in 2018 we were at the top of the business cycle, and in 2021 we were rapidly emerging from a serious recession caused by Covid 19. In contrast, currently we are in a minor slowdown caused by the "hangover effects" of the Covid 19 medicine, which was massive central bank spending which depressed interest rates to ridiculously low levels. In my judgment, we have a more favourable economic environment than at the time of the three other hearings as is shown by the stock market recently hitting new highs.*[28]

In responding to a request for information, Dr. Booth said this about the local provincial economy.

*Dr. Booth has previously in Newfoundland Power applications reported on economic data for Newfoundland and Labrador, but has deleted this discussion since it does not affect the main macro-economic factors that affect the fair ROE through forecast interest rates, inflation and GDP growth. He is aware of conditions in the province and the fact that it has historically had structurally higher unemployment due to its industry composition. For example, the 2023 unemployment rate was 10.0%, and is forecast to marginally increase to 10.3% over the next two years, before recovering as forecast GDP growth returns to greater than 2.0%.*

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[27] June 20, 2024 Transcript (page 54, line 2 to line 5; page 92, line 5 to line 9; page 96, line 22 to page 97, line 21; page 105, line 7 to line 22; page 112, line 11 to line 18; page 163, line 1 to line 19)

[28] April 2024 Written Evidence of Dr. Laurence Booth (page 1, line 12; page 1, line 16 to page 2, line 2)

*Dr. Booth would also point out, as he did in past hearings, that personal disposable income in the province was higher than any other province except the western three of British Columbia, Alberta and Saskatchewan. It was higher than in both Ontario and Quebec, while recent economic weakness is in part due to the impact of returning the provincial budget to a surplus.*

*Dr. Booth has not considered a short-term economic forecast for the province because the consistent ability of NP to over earn its allowed ROE for the past 25 years indicates that provincial weakness or strength does not translate into significant forecasting risk for NP. He also pointed this out in 1992 when Newfoundland Telephone was regulated by the CRTC and had a better bond rating than the province, that is, provincial risk does not easily translate into utility risk.*[29]

Any risk associated with Muskrat Falls post-2030 is ratepayers' risk, not that of Newfoundland Power. While paying for Muskrat Falls post-2030 may yet prove be an issue for Newfoundland Power's customers, Dr. Booth does not think the Board or the Provincial Government would see the utility financially harmed. He explains his position.

*And I said then, and I still hold to this, it's what I view as the regulatory compact in Canada. If problems occur, then firms bring these problems to the regulator and frequently compromises are worked out. This is part of the regulatory bargain that I now refer to as the regulatory compact. Only regulated firms have this capability. For example, if a competitive firm suffers a supply shock, then the stockholders are directly affected. But in contract, a regulated firm can, that have losses, put in a deferral account and allocate it to future customers or apply to the regulator for other means to protecting the stockholder from loss. Consequently, it is unreasonable to expect no action on the part of the regulator…I still hold to that. I believe that you commissioners are reasonable people and I believe that every board across Canada has got reasonable people and we look at our utilities and we protect our utilities. I've never seen an instance when a utility wasn't protected in Canada, and that's part of who we are in Canada. We don't hold the utilities out to dry…So, how can I verify that? Every hearing I've been involved in, at least for the last 25 years, I've asked for all the evidence on the allowed rate of return and the actual rate of return, and for Newfoundland Power, last 30 years, it's over earned its allowed ROE…*

*But the fact that they earn their allowed ROE should be used by the Board to assess how good a job they're doing in transferring the risk from the utility to the ratepayers, which is what all these deferral accounts do. And that's part of the regulatory protection and the regulatory compact in Canada.*[30]

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[29] NP-CA-007 (line 16 to line 37)

[30] June 19, 2024 Transcript (page 19, line 157 to page 158, line 18) and June 20, 2024 Transcript (page 163, line 1 to line 8)

Newfoundland Power considers itself to be an "above average risk" Canadian utility due to Muskrat Falls power supply reliability issues and power supply costs risks. As to the power supply reliability issues, Newfoundland Power's CEO testified as follows.

*MR. MURRAY:*
*A. There would be two components. It would be, yes, the reliability of power delivered over the LIL, and the backup provided by Holyrood.*

*SIMMONS, KC:*
*Q. Right. So, one is the reliability of the LIL, will there be outages, forced outages, on the LIL, would be a concern, and then secondarily, if because of that there has to be backup power constructed, there will costs associated with that. Are those—I don't mean to put words in your mouth, but I just want to make sure I understand what the concerns are there.*

*MR. MURRAY:*
*A. Yes, that is correct. You know, in the short-term, I mean, there's reliability concerns with the LIL before the backup is built. You know, if Holyrood is not available, you know, we will be short of power on the Island.*[31]

However, Mr. Simmons, counsel for NL Hydro, then pointed out that for the twelve months ended March 31, 2024, the forced outage rate on the Labrador Island Link (LIL) was 2.7%, meaning the LIL was available 97.3% of that year. Over the past decade, the availability of Newfoundland Power's generation averaged 95%, meaning its forced outage rate averaged 5.0%. The LIL's 2.7% forced outage rate was better than the 5.0% forced outage rate for Newfoundland Power's generation.[32] And while a forced outage of the LIL during heavy load conditions could cause a failure of NL Hydro supply to Newfoundland Power, that would occur only if generation at Holyrood was simultaneously unavailable.

Relevant to the power supply cost risks is testimony by Mr. Coyne concerning both KKR's 2024 purchase of Emera Inc.'s interest in a revenue stream from the Labrador Island Link and implementation of the Muskrat Falls rate mitigation plan. Testimony from Mr. Coyne in relation to the former is the following.

*COFFEY, KC:*
*Q. And are you aware that May 28th, 2024 that Emera and KKR and Newfoundland and Labrador Hydro announced that KKR was buying Emera's interest in the LIL?*

*MR. COYNE:*
*A. Yes.*

*COFFEY, KC:*
*Q. And are you aware, generally aware of the financial details?*

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[31] June 13, 2024 Transcript (page 143, line 11 to page 144, line 7)
[32] June 13, 2024 Transcript (page144 to page 155)

*MR. COYNE:*
*A. Well, I'm aware of what's in the public domain pertaining to those details.*

*MR. COYNE:*
*A. Well, my understanding is that Emera had an ownership interest in the Labrador Island Link and it has reached an agreement with KKR to sell those ownership interests effective, as we've just learned, June 4th, but it looks like Emera will also remain, as they say actively involved in the partnership, along with Hydro, continuing to provide sustaining capital investments to support ongoing operations. So I don't know exactly what that means without looking at all the legal documents around how that separation occurred, but the ownership rights have transferred to KKR for a sum of 1.19 billion Canadian.*

*COFFEY, KC:*
*Q. Now the first, like a larger paragraph below the bullets, the last sentence of that paragraph, it reads "The transaction value is 1.19 billion Canadian made up of 957 million Canadian in cash and 235 million Canadian for assuming Emera's obligation to fund the remaining initial capital investment." And this, and Mr. Coyne, is your understanding that this is being, the income flow in relation to this investment by Emera and now by KKR, is based on the 8.5 ROE, 8.5 percent ROE that this Board sets that it currently has for Newfoundland Power?*

*MR. COYNE:*
*A. That is my understanding.*

...

*MR. COYNE:*
*A. My understanding is that KKR is paying 100 – 1.19 billion Canadian for obtaining Emera's ownership interest in LIL and as a result of that, it will have various rights and obligations, some of which Emera will retain, some of which the new owner will acquire, including the right to an income stream that's – well, I know more than what's in this paragraph because there's a statute behind this and there are contracts that are complex behind this...So, that knowledge tells me that what the Board does pertaining – under current statute and under the current contracts, what the Board does here also affects the LIL's allowed rate of return.*

...

*COFFEY, KC:*
*Q. And in relation to this though, in terms of your understanding of the contracts that exist, as you – well, you didn't allude to it, in fact you referred to your knowledge otherwise. Within the past month then, is it fair to say that KKR was prepared to put almost 1.2 billion dollars into buying an interest in the LIL, the payment return on equity of which is currently eight and a half percent?*

*MR. COYNE:*
*A. That's true. That's right here. Now, what that doesn't tell us is what their expectations are for the future around that ROE.*

...

*COFFEY, KC:*
*Q. Now, one other thing they would have known was this, wouldn't they, if they're – you know, due diligence sort of people, they would have known that – I think it was on May 16th of 2024 the rate mitigation implementation was announced. They would have known that.*

*MR. COYNE:*
*A. They would know that.*

...

*MR. COYNE:*
*A. Yeah. But they – you know, here's the issue with an investor like KKR or any investor, if they're looking at the LIL, this is a – most transmission assets are 50-year transmission facilities and this one was just completed. So, they would need to have developed a 50-year view of the economics of this transmission line and today, at eight and a half percent, and all the other conditions surrounding the LIL would have just been the starting point of the economic and financial analysis. A concern that they would have had to have considered is whether or not the Muskrat Falls Project, under the rate mitigation plan, was going to be sufficient so that the economic viability of that line would withstand the future challenges associated with rolling the full investment for Muskrat Falls into rates. So, it would have been a complex consideration of business, financial and political risks that they would have needed to have considered and not just the simple ROE today.*

*COFFEY, KC:*
*Q. Yeah, and having considered it all, they bought in apparently.*

*MR. COYNE:*
*A. They did.*[33]

In relation to the latter, Mr. Coyne testified as follows.

*COFFEY, KC:*
*Q: How then – would you agree that the actions of Newfoundland and Labrador Hydro and the Provincial Government and the Federal Government of Canada to date have shown a willingness by those three parties to ensure that rates, increases in rates for*

[33] June 18, 2024 Transcript (page 138, line 1 to line 12; page 143, line 4 to page 144, line 10; page 147, line 1 to line 11, and line 15 to line 19; page 149, line 9 to line 23; page 152, line 9 to line 17; page 157, line 11 to page 158, line 14)

*Newfoundland, for the electricity ratepayers of this province, is kept to a reasonable amount at least for the next six and a half years?*

*MR. COYNE:*
*A. I would say yes, they have collaborated to achieve that outcome.*

...

*COFFEY, KC:*
*Q. Well, with all due respect, sir, we do know now that the Federal Government has shown a willingness to support ratepayers, provide financial support. We do know that the Provincial Government has shown a willingness, correct?*

*MR. COYNE:*
*A. That's correct.*

*COFFEY, KC:*
*Q. And as you say, in the past, that was not known. That was an unknown.*

*MR. COYNE:*
*A. It was anticipated, but the magnitude of the support was unknown and remains unknown. You know, if you look at the last line of the press release, I think it says everything I said more elegantly. What that might look like beyond 2030 will be reviewed again into the future.*

*COFFEY, KC:*
*Q. Yes.*

*MR. COYNE:*
*A. And the credit rating agencies also focus on that; that it's a problem that's yet to be solved. It's an interim solution or it's a short-term solution.*

*COFFEY, KC:*
*Q. But it is certainly no worse now than it was, in terms of being an unknown, than it was in 2016, 2019 and 2022?*

*MR. COYNE:*
*A. I'd say that's right.*

*COFFEY, KC:*
*Q. And in fact, you would agree, wouldn't you, that there's at least some more certainty for the next six and a half years than there was at each of those years for the next six years?*

*MR. COYNE:*
*A. There's – yes, there's some more certainty in that rate period.*[34]

Newfoundland Power's overall risk profile reflects financial risk in the current markets and the business risk of its operations. The Board has in the past consistently determined that Newfoundland Power is, overall, an average risk utility in relation to other Canadian utilities.

In 2016, the Board felt that the risks then associated with Muskrat Falls, both in terms of supply and costs, were real and might have an impact on Newfoundland Power's business risk. The Board also accepted that the economic indicators for the province were not strong and could also have an impact on Newfoundland Power's business risk. However, the Board noted that credit-rating agencies considered Newfoundland Power's business risk as low. The Board found that Newfoundland Power continued to be an average risk utility.

In light of the certainty that increases to the power supply costs that NL Hydro can charge to Newfoundland Power are capped at 2.25% per annum at least until 2031, Newfoundland Power remains an average, if not lower than average risk Canadian electric utility.

2.5.2 Capital Structure

In explaining the practical significance of Newfoundland Power's common equity ratio, Dr. Booth wrote:

> *A firm's capital structure has a direct impact on the overall cost of capital as conventionally defined in finance, since equity costs are paid out of after-tax income, whereas debt costs are tax deductible. Hence, for example, if long term debt costs are about 5.11 % and equity costs are 8.50% as currently allowed NP, then at a 30% tax rate (similar to NP's future cost), the pre-tax costs are actually 12.143% for the common equity (.085/(1-.30)); since the ROE is after tax, it attracts a prior income tax charge compared to 5 .11 % for the debt. This means a spread between the two of 7.03%. In terms of the revenue requirement, this means that every dollar shifted from debt into equity costs the rate payers 7.03% times the percentage change in the rate base in additional revenue requirement.*[35]

Dr. Booth also testified on this subject.

> *...There's absolutely no question Newfoundland Power's 45 percent is out of line. I've been saying that ever since I've been coming here, I think, since 2009. The Board has not made any changes because it's always sort of said something like, "well, Muskrat Falls is coming along. Let's wait and see". I'm not pushing hard on 45 percent – sorry, 40 percent. What I'm saying is go back and put in the PUB's decision in '96/97 a range of 40 to 45 percent. So, the bond rating agencies know that it's 40 to 45 percent and if you want to go to 40 percent, I will recommend you go immediately. Even then I've*

[34] June 18, 2024 Transcript (page 61, line 1 to line 13; page 63, line 22 to page 65, line 12)
[35] April 2024 Written Evidence of Dr. Laurence Booth (page 105, line 3 to line 11)

*been I think quite conservative saying go slowly, a little bit over time. Add preferred shares. Don't shock the market. But recognize that 45 percent is excessive compared to the Canadian comparators...*[36]

*DR. BOOTH:*
*A. ...Any change in the common equity ratio, simply because it is perceived to be a longer-term thing, they'd look at that very seriously. Now, they've noted on numerous occasions that Newfoundland Power has a very generous common equity ratio. So, which is why I said to the Board, at least flag – you go back to '96/97 and just reaffirm that the Board believes that the common equity ratio should be between 40 and 45 percent...But I'd like it back on the record that the appropriate common equity ratio is 40 to 45 percent. And then the rating agencies will look at that and they'll say, "oh, well, could be 40 percent", the same as every other – pretty much the same as every other electric utility in Canada. That's not a shocker.*

*GREENE, KC:*
*Q. But based on your answer, wouldn't be for this particular rate case. You would want the Board to give some indication that they're going there in the future?*

*DR. BOOTH:*
*A. Absolutely. I've made this recommendation for 15 years. So, I mean, it's not – shouldn't be a surprise to the Board or the company that I think that the common equity ratio is out of line with other Canadian owned electric utility companies, and each time the Board has said not now, not now Muskrat Falls, not now other reasons, and I could understand the Board making that decision, but I think it's about time, I mean, the Board stop saying not now.*[37]

The justification for the 45% equity ratio proffered by Newfoundland Power has in the past been, and in 2024 continues to be, that a high equity component is needed to mitigate its small size and low growth potential, and that its present capital structure is viewed as a credit strength. Newfoundland Power's position is that the requested return on equity of 9.85% is fair based upon a capital structure with a target ratio of 45%. While Concentric says the current 45% common equity ratio remains the minimum appropriate, its report does acknowledge that: "*Newfoundland Power's deemed common equity ratio of 45 percent is higher than the five other Canadian investor-owned electric operating utilities*" listed in Figure 33 of its report [namely, Alberta Electric Utilities: 37.0%; FortisBC Electric: 41.0%; Ontario Electric Utilities 40.0%; Maritime Electric 40.0%; and Nova Scotia Power: 40.0%]; indeed, Concentric's Canadian Electric Average of 39.6% is even less than Dr. Booth's recommendation of 40%.[38]

Dr. Booth described the situation of utilities such as Newfoundland Power existing within holding companies such as Fortis Inc. as follows:

[36] June 19, 2024 Transcript (page 165, line 6 to line 25) June 21, 2024 page 71, line 2 to
[37] June 21, 2024 Transcript (page 77, line 2 to page 78, line 14)
[38] November 7, 2023 Concentric Cost of Capital Report (page 55, line 11 to line 16)

*...there are tax and other advantages to a company using debt. For ROE regulated utilities, the tax advantage flows through to rate payers in terms of a lower tax charge in the revenue requirement. However, for utilities owned within a holding company this situation is worse, since the parent has an incentive to finance the utility with as much equity as possible, so that the tax advantages to financing with debt are shifted to the parent. In this way it is the parent's shareholders that get the tax advantages to debt financing and not the utility rate payers. This is often called the "double leverage" problem, where the utility assets support debt at both the utility level and then again at the parent level.*[39]

As noted above, Dr. Booth recommends that Newfoundland Power's common equity ratio be reduced to 40%, which would bring it in line with, but still be slightly above, the Canadian utility average. He states that the additional above average 5-6% equity thickness is not warranted based on Newfoundland Power's business or financial risk, nor is it required to maintain its credit metrics. In response to Newfoundland Power's professed concern about the effect Dr. Booth's recommendation of a 7.7% ROE and 45% equity ratio would have on how rating agencies would view its credit metrics, Dr. Booth says the following.

*GREENE, KC:*
*Q. And you weren't here when we discussed with Ms. London, Vice President of Finance for Newfoundland Power, the Moody's reports and the impact on the credit metrics of various scenarios, but when we looked at those scenarios, and I can bring it up, which I hadn't intended to do, it would be clear that Newfoundland Power would not be able to make the 16 to 18 percent coverage for the cash flow to debt operations that Moody requires for the current rating with your recommendation. Would you like to see that?*

*DR. BOOTH:*
*A. I remember that Moody's said that it's got a temporarily there's a problem with one of the ratios but -*

*GREENE, KC:*
*Q. Right.*

*DR. BOOTH:*
*A. - you got to remember the ratios, the AUC looks at these ratios, and particularly the S&P ratios, and it uses the lowest numbers in the AUC to maintain the standard, because they don't actually use those ratios. So, if it's a temporary phenomenon, then they'll look at that and say, "well, whatever caused that change, it will disappear and it won't be a factor". So, you got to distinguish between temporary and sort of permanent factors. When you look at my data, according to the AUC use – and they use the S&P financial metrics, then their estimates for 37 percent common equity ratio and a pre-tax – and I have to emphasize, pre-tax return on equity, not the after-tax return on equity, more than satisfies the credit rating agencies. So, I checked the numbers. 7.7 percent, that would be different for an Alberta utility than for Newfoundland Power. Now why is that? Well,*

[39] April 2024 Written Evidence of Dr. Laurence Booth (page 111, line 22 to page 112, line 4)

> *I hate to tell you, you're in a high tax jurisdiction. So, along with 7.7 percent comes a higher tax burden, and the pre-tax of 7.7 percent puts you in line with the nine percent after-tax in Alberta in their schedule with the fact that Alberta, they're parallel tax rate. So, as far as the rating agencies are concerned, the more tax Newfoundland Power pays, the better it is for the bond holders. I know that sounds crazy, but that's absolutely correct, because they look at the earnings before interest and tax. So, when you look at the rating metrics, my recommendation would satisfy the – not only does it satisfy the fair return standard, it certainly satisfies an A-3 bond rating. Whether it satisfies an A-2 bond rating, which is the highest of any utility in Canada except Fortis Energy FEI, Fortis BC Energy out in BC, gas utility, and so I would not regard dropping from A-2 to A-1* (sic) *[A-3] the same as most utilities in Canada as being a shock, but I wouldn't be surprised if it is dropped from an A-2 to an A-1, but that – obviously I'm not a bond rater, but I'm just going by how they rate other Canadian utilities.*[40]

In summary, Newfoundland Power's credit metrics would not be destabilized by virtue of a modest reduction of its common equity ratio or its allowed return on equity.

## 2.6 Methodologies for Estimating Return on Equity

### 2.6.1 Approaches

In Order No. P.U. 18(2016), the Board summarized the methodologies used in that application for estimating the appropriate return on equity.

> *The appropriate return on equity to be used for utility rate setting is usually selected based on the results obtained from conventional financial models, including the Capital Asset Pricing Model (CAPM), the Discounted Cash Flow method (DCF), and others. Experts often have different opinions on which model, or combination of models, should be relied upon in any given proceeding for the determination of the fair return on equity but generally acknowledge that the prevailing financial and economic conditions at the time are important considerations affecting the methodology choice and results.*
>
> *In past proceedings cost of capital experts have canvassed multiple methodologies and resulting equity returns for the Board's consideration. Prior to 2009 the Board relied principally upon the equity risk premium test, referencing the stability of the bond market at the time. In its most recent decisions on cost of capital the Board has relied primarily on equity risk premium tests, giving more weight to CAPM and less weight to DCF results in arriving at a fair return.*
>
> *CAPM is based on the relationship between the required return for a security and the risk of the security. The model determines the required or fair return as the sum of the risk free rate plus a risk premium for the risks associated with the security. The risk free rate is generally accepted as the forecast long Canada bond yield. The risk premium for the security is comprised of the market risk premium times the security's relative risk or beta. The beta is usually derived statistically based on an analysis of historical returns*

[40] June 21, 2024 Transcript (page 82, line 8 to page 84, line 25)

*for the security and overall capital returns for the same period. The inputs to be used for CAPM are usually the subject of expert opinion during cost of capital proceedings.*

*The DCF model uses the current dividend yield of the company's shares plus expected future dividend growth rate to estimate the cost of a company's common equity. There are several forms of the DCF model depending on the assumptions for future growth. A constant growth DCF model assumes constant growth in dividends and earnings in perpetuity, at a constant annual rate, and relies on analysts' estimates of future earnings growth. A multi-stage model assumes growth to occur at different stages and is more complex; but still requires estimates of future growth. During cost of capital hearings the appropriate growth rate to be used in the DCF models is usually the subject of expert opinion.*

The Board therein decided to "*give primary consideration to the CAPM estimates in conjunction with other evidence and information in the determination of a fair return for Newfoundland Power.*"

In his written evidence, Dr. Booth says:

*The premier model that incorporates the risk return trade-off between Government of Canada default free securities and risky securities is the Capital Asset Pricing Model or CAPM. This is the model used by most boards in Canada, including this one in past decisions... Meaning that the investor's required or fair rate of return (K.) or cost of equity capital is equal to the risk-free rate (RF) plus a risk premium. The contribution of the CAPM is simply to break the risk premium into two components, which are the market risk premium (MRP) and the security's relative risk or beta coefficient ($\beta$). In this sense it is simply a refinement of more general risk premium models.*[41]

And he explains why CAPM is relied on:

*Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major "laws' of finance: the time value of money and the risk value of money. I will discuss the third law of finance, the tax value of money later, but the time value of money is captured in the long Canada bond yield as the risk-free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct, the estimate will be in the right "ballpark." Where the CAPM gets controversial is in the beta coefficient since risk is constantly changing, as are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further, it also makes testing the model incredibly difficult. However, the CAPM measures the right thing, which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory.*

*The CAPM is overwhelmingly the most important model used by a company in estimating their cost of equity capital...*

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[41] April 2024 Written Evidence of Dr. Laurence Booth (page 37, line 10 to line 19)

*In response to persistent criticism of the CAPM by some witnesses, I have started to look at alternatives to the CAPM. The most common in the academic literature are known as multi-factor models. Although not widely used to estimate the equity cost, they are popular amongst academics. The CAPM is regarded as a one-factor model because market risk through beta is the only source of risk. Instead, multi-factor models extend the CAPM to include additional risk factors that have been identified in stock market returns...*

*Despite the popularity of these multi-factor models amongst academics, and increasingly in the investment field, they have doubtful value in regulatory hearings. There are two reasons for this. First, they do not make much difference in the overall estimates, Second, they need more inputs, each of which is likely to be extremely contentious in cross examination. While the size of the market risk premium can be estimated with some degree of accuracy, that cannot be said for the size and value premiums. In fact, many believe the size premium has disappeared as coverage of small stocks has increased, while for many the value premium causes theoretical problems. I discuss the multi-factor model mainly because it is the major "competitor" to the CAPM, and while other witnesses frequently criticise the CAPM, they never discuss multi-factor models* ***and instead rely on ad hoc models and estimation techniques that have no academic credibility.***[42] [bolding in the original]

Dr. Booth's detailed and exhaustive explanation of how he conducted his CAPM estimates concludes with:

*I would judge the fair ROE based on my CAPM estimates to be in a range 7.28-8.13%, or a recommended ROE of 7.70%... My DCF analysis was used to directly estimate the overall equity market return which has informed my assessment of the appropriate market risk premium. This is extremely important because it is the basic ingredient in any risk premium approach as it indicates the market's trade-off between risk and return.*[43]

Dr. Booth describes the DCF model as follows:

*DCF stands for discounted cash flow, which is the basic method used for valuing bonds as well as companies by professional investors and corporate executives. It was extensively used in Canada to estimate utility fair rates of return before the mid 1990s when risk premium evidence became more important...* ***The upshot of this is that any DCF estimate relying on short run earnings growth to proxy for long run DPS growth is biased high****. The shorter the horizon for the average growth estimates, the bigger the bias. This is before consideration of the well-known bias involved with sell side analyst forecasts...Survey results in both the U.S. and Canada show that DCF estimate of the fair rate of return is not placed in as high a regard as the risk premium or CAPM estimate*

[42] April 2024 Written Evidence of Dr. Laurence Booth (page 37, line 20 to page 38, line 19; page 39, line 7 to line 12; page 41, line 7 to line 16))
[43] April 2024 Written Evidence of Dr. Laurence Booth (page 72, line 5 to line 6)

*for individual firms. Partly in response, I have traditionally viewed my DCF estimates as "checks" on my CAPM estimates, since in my view CAPM estimates have usually been in the right "ballpark."*[44]

2.6.2 Proxy Groups and Use of U.S. Data

As return on equity (ROE) is a market-based concept and shares in Newfoundland Power are not publicly traded, it is necessary to establish a group of companies that are publicly traded and comparable to Newfoundland Power's business and financial characteristics to serve as its "proxy" for the purpose of estimating the return on equity. Use of a proxy group (or groups) is intended to mitigate the potential effect of anomalous events associated with relying on a single proxy company.

Concentric's position is that the Board should use data drawn from U.S. proxy groups without any adjustment in setting the fair return for a Canadian utility. Concentric justifies its approach by arguing that: Canadian data is limited by the small number of publicly traded utilities; Canadian and U.S. financial markets are integrated; the regulatory regimes in Canada and the U.S. are similar; and Canadian utilities need to compete globally for capital. Concentric identified three proxy groups; six Canadian companies; ten U.S. companies; and a combined fourteen-member North American group, which companies are claimed by Concentric to be comparable to Newfoundland Power with respect to business and financial risk.

For reasons set out herein, Concentric's unadjusted usage of data for Concentric's proxy companies cannot reasonably be used for determining Newfoundland Power's fair return on equity. Members of Concentric's proxy groups, including the Canadian proxy group, include vertically integrated utilities with extensive and riskier generation and different other risk attributes than does Newfoundland Power.

To the extent the Board relies on data for these proxy groups, the Board should be consistent with its past practice, and where it utilizes U.S. data apply a 50 to 100 basis points downward adjustment to results based on U.S. data where appropriate.

As regards the choice and use of proxy groups comprised largely or entirely or of U.S. companies and the use of U.S. data, the Board in Order No. P.U. 18(2016) stated:

*The Board accepts that the limited Canadian data may require the use of U.S. data in some circumstances, and also that integration of Canadian and U.S. financial markets may support this approach. However the Board does not believe that the integration of these markets means that U.S. utilities should be considered to be the same as Canadian utilities. While the Board acknowledges that other Canadian regulatory boards have recently determined that it is not necessary to adjust the U.S. utility data, the Board continues to believe that an adjustment is appropriate. The Board believes that there are differences in risk and associated returns between Canadian and U.S. utilities and is not*

[44] April 2024 Written Evidence of Dr. Laurence Booth (page 50, line 3 to line 6; page 52, line 16 to line 19; page 53, line 22 to line 25)

*satisfied that the results from using U.S. data, in the form of a proxy group of companies, can be accepted without adjustment to account for these differences. In Order No. P.U. 13(2013) the Board accepted a downward adjustment of 50-100 basis points in relation to the U.S. utility results. Dr. Booth's evidence is that an adjustment in this range remains appropriate.*

*The Board accepts the use of U.S. data but only with adjustment, and will apply a 50-100 basis points downward adjustment to results based on U.S. data where appropriate.*

Dr. Booth says this about the use of U.S. data in Canadian regulatory proceedings to determine the cost of capital for Canadian utilities.

*Mr. Coyne and Mr. Trogonoski base their evidence heavily on returns from U.S. utility holding companies (UHCs); even their North American sample is predominantly American. I can understand this because, as Americans, their point of reference is the U.S. and not Canada. However, I continue to regard such estimates as biased high when applied to pure Canadian regulated utilities for three reasons.*

- *First, they are mainly from utility holding companies rather than the underlying operating companies. This means they are further away from the cash flow and rely on the payment of dividends to service their own debt and to make dividends. If this flow is disturbed, they may have problems servicing their own debt, which makes them riskier than the underlying operating companies.*

- *Second, U.S. financial markets exhibit more risk than the Canadian markets and have generated higher risk premia in the past where the realized market risk premium since 1926 has been 1.71 % higher in the U.S. than in Canada. This is demonstrated in my Appendix B, where I estimate the market risk premium for both countries. Moreover, much of this is due to the Ibbotson (now Kroll) data that was specifically started in 1926 to catch the run up to the 1929 stock market crash. As the Credit Suisse report shows in Schedule 14 of my Appendix B, if the data is taken back to 1900 the U.S. market risk premium drops to 4.7%. Further, the failure of "light handed" U.S. regulation has been reinforced yet again by the failure of Silicon Valley Bank and two other regional banks in March 2023.*

- *Third, although the principles of regulation are largely the same between the U.S. and Canada, as is widely recognized the implementation is different, as was demonstrated in the 2000s with the U.S. regulation of their banks and their telecom companies.*

*I have long regarded having to use proxies to estimate the fair return for a private, non-traded, regulated, Canadian utility as equivalent to looking through a "dirty window".*[45]

[45] April 2024 Written Evidence of Dr. Laurence Booth (page 75, line 3 to line 28)

Dr. Booth explained his use of the term "dirty window" by saying:

> *It is almost impossible to find a traded utility with the same characteristics as NP or any pure regulated utility, particularly in Canada. This is because as low risk, cash rich utilities they are the perfect foundation for a holding company where the cash can be used to finance other investments.. At each stage the traded company became more remote and a poorer proxy for each regulated utility...*[46]

In support of his "dirty window" analogy, Dr. Booth says:

> *...In Schedule 9 are the earned ROEs of 14 Electric UHCs that have in the past been used in comparable samples to a Canadian operating utility like NP. Over the period 2011 to 2023, NP earned an average ROE of 8.92% compared to the U.S. sample average of 9.19%. However, note two important facts. First the average U.S. UHC ROE ranges from the 6.18% of Duke Energy to the 13.38% of Nextera. I suspect that neither of these values would be accepted as a fair ROE in a Canadian jurisdiction. Second, the volatility of the ROE as measured by the standard deviation of the earned ROE has ranged from 0.56% for Allete to 6.57% for Entegy, with an average of 2.69%. In contrast, NP's ROE volatility is 0.16% lower than that of any of these U.S. UHCs...*
>
> *The fact is the holding companies that we look at to judge the risk of a Canadian operating company like NP are all considerably riskier as this Board has decided in the past. Note this is not a U.S. versus Canada comment, since the same now applies to several Canadian utilities that are fast become large multi company holding companies themselves...*
>
> *In my judgment, NP is lower risk than any sample of U.S. UHCs regardless of the screens used to create a "low risk" sample...*[47]

Dr. Booth's concern about using the constant growth DCF method to estimate fair returns are: the existence of analysts' bias; and the assumption that growth goes on in perpetuity. Dr. Booth says there is absolutely no question that analysts are biased in the sense that they tend to be optimistic. Dr. Booth says that the same issue of analysts' bias applies to the multi-stage DCF method as to the constant growth DCF method, although not to the same degree. His position is that the DCF method should be rejected as a method to estimate the fair return on equity. While Dr. Booth uses DCF analysis of the overall Canadian and U.S. stock markets and U.S. gas and electric companies to inform his judgment on the fair return on equity, he makes adjustments for analysts' bias and uses growth rates at sustainable levels. Dr. Booth summarizes his DCF conclusions thusly.

> *From the forgoing DCF estimates I draw the following conclusions:*
>
> - *The overall equity market return in Canada is in a range 8.10%-8.75% and that for the US SP500 firms slightly higher than the top of the range for Canada at 9.6%. A reasonable range is 8.75-9.6% using the top of the estimates.*

[46] April 2024 Written Evidence of Dr. Laurence Booth (page 75, line 30 to line 33; page 76, line 4 to line 5)
[47] April 2024 Written Evidence of Dr. Laurence Booth (page 77, line 8 to line 15, page 78, line 22 to line 25)

- *The individual DCF estimates for US gas companies based on analyst growth forecasts would put their equity cost at 8.84-8.90%. However, these forecasts are biased high and inaccurate estimates of their underlying DPS growth rates. Removing this bias by using sustainable growth forecasts lowers this estimate to 6.75-6.87%.*

- *Analyst earnings growth rate forecasts are optimistic (biased) estimates of dividend growth rates since earnings are much more volatile. Over long periods of time, the growth rate of earnings and dividends for S&P500 firms is approximately that of US GDP. However, simple average growth rates of earnings, which are what analysts forecast, are almost twice as high as for dividends, making them biased when used in the constant growth DCF model.*

- *SP500 utility earnings and dividend growth rates since 1967 and up till 2017 confirm that over very long periods neither have grown at close to the US GDP growth rate. This is what logic would dictate since their dividend yields are about twice that of the SP500 index, meaning that with the same forecast growth rate their equity cost is higher. Logic and actual beta estimates confirm that these U.S. UH Cs are lower risk due to the impact of regulation.*

- *My best estimate is that U.S utilities can grow at 65-68% of the growth rate of US GDP in the long run, which is the historic experience since 1967. This implies a DCF equity cost less than 7.0%. Adding a 0.50% floatation cost allowance implies a fair rate of return similar to that for Canadian UHCs of 7.5%.*[48]

Following a detailed explanation of his CAPM analysis, Dr. Booth describes his CAPM estimate for a benchmark Canadian utility.

> *With a market risk premium estimate of 5.5-6.0% and a beta range of 0.50-0.60, the range for the utility risk premium is 2.75%-3.6%. Adding these risk premiums to the 3.80% forecast for the long Canada bond and a 0.50% flotation cost allowance gives a range of 7.05%-7.90% and a mid-point of 7.45%. This would be a conventional or generic CAPM estimate for a benchmark utility prior to 2008. Why I reference 2008 is that it was the year of the financial crisis when the NEB ROE adjustment formula was still being used. These were formulae that tied the fair ROE to changes in the forecast Long Canada bond yield.*[49]

Dr. Booth summarizes his CAPM-formulated recommendation for the return on equity for Newfoundland Power.

> *For 2024, the NEB formula ROE produces a fair ROE including issue cost of 7.88% based on a forecast long Canada bond yield of 3.45%. The adjusted ROE formula produces a fair ROE of 8.18%. This is because the credit spread in October 2023 was*

[48] April 2024 Written Evidence of Dr. Laurence Booth (page 21, line 11 to page 22, line 4)
[49] April 2024 Written Evidence of Dr. Laurence Booth (page 45, line 2 to line 8)

*1.58%, and high relative to the pre-2008 average for an A credit. As a result, the credit spread adjustment increased the NEB formula ROE by 0.30%. For 2025, with a forecast LTC yield of 3 .8% and the current credit spread of 1.40%, the modified ROE formula gives a fair ROE, including issue costs, of 8.40%, which is not too dissimilar to the current allowed ROE for NP.*

*I regard the credit spread adjustment as making the standard risk premium estimate, in part using long run values, conditional on the state of the capital markets. Over the business cycle this adjustment should average out to zero, but currently with the slight slowdown I warrant the CAPM estimate as being marginally low and would add the credit risk adjustment for a conditional CAPM (CCAPM) rounded estimate of 7.70% which is slightly lower than that produced by the modified NEB formula.*

*My overall CAPM fair return estimates are, therefore, as follows:*

| | *Low* | *High* |
|---|---|---|
| *Forecast long Canada bond yield* | *3.80* | *3.80* |
| *Credit risk adjustment* | *0.23* | *0.23* |
| *Utility risk premium* | *2.75* | *3.60* |
| *Adjustment to ROE* | *0.50* | *0.50* |
| *Estimate* | *7.28* | *8.13* |

*The estimate of 7.7% is in a range from 7.28% to 8.13%, reflecting a 3.9% premium over the forecast LTC yield.*[50]

2.6.3 Concentric's Flawed Choice of Proxy Utilities for Newfoundland Power

Dr. Booth points out the flaws in Concentric's choice of comparator utilities for Newfoundland Power. Newfoundland Power is a Canadian operating utility, wholly owned by Fortis Inc. Newfoundland Power uses thermal and hydro power to generate 7% of the electricity it sells; it buys the other 93% from NL Hydro and simply resells it.

Concentric chose ten U.S. comparators. None is an operating utility. All are holding companies, with as many as seven subsidiary operating utilities. Concentric's U.S. comparators are all publicly traded. Many of their subsidiary utilities operate in multiple states, and are regulated by multiple U.S. federal and state authorities. Many of the operating subsidiaries self-generate a significant portion of the power they sell; many buy and sell significant quantities of power on spot markets, some in multiple U.S. regional grids. Some of the subsidiaries operate nuclear plants, while others rely largely on gas-powered thermal plants.

Dr. Booth's report provides brief 'Yahoo' descriptions of the ten U.S. utility holding companies used by Concentric in its U.S. Electric Utility Group as comparators to Newfoundland Power.[51] Even

[50] April 2024 Written Evidence of Dr. Laurence Booth (page 48, line 10 to page 49, line 12)
[51] April 2024 Evidence of Dr. Laurence Booth (Appendix A. Brief description of US electric utilities from Yahoo. Mr. Coyne and Mr. Trogonoski's ten companies)

these bird's eye views of Concentric's U.S. comparators makes it clear how dissimilar they and Newfoundland Power are.

1. Alliant Energy Corporation operates as a utility holding company that provides regulated electricity and natural gas services in the United States. It operates in three segments, Utility Electric Operations, Utility Gas Operations, and Utility Other. The company, through its subsidiary, Interstate Power and Light Company (IPL), primarily generates and distributes electricity, and distributes and transports natural gas to retail customers in Iowa; sells electricity to wholesale customers in Minnesota, Illinois, and Iowa: and generates and distributes steam in Cedar Rapids, Iowa. Alliant Energy Corporation, through its other subsidiary, Wisconsin Power and Light Company (WPL), generates and distributes electricity, and distributes and transports natural gas to retail customers in Wisconsin; and sells electricity to wholesale customers in Wisconsin. It serves retail customers in the farming, agriculture, Industrial manufacturing, chemical, packaging, and food industries, as well as wholesale customers comprising municipalities and rural electric cooperatives. In addition, the company owns and operates a short line rail freight service in Iowa: a Mississippi River barge, rail, and truck freight terminal In Illinois; freight brokerage services; wind turbine blade recycling services; and a rail-served warehouse in Iowa. Further it holds interest, in a natural gas-fired electric generating unit near Sheboygan Falls, Wisconsin: and a wind farm located in Oklahoma. T11e company was formerly known as Interstate Energy Corp. and changed its name to Alliant Energy Corporation in May 1999, Alliant Energy Corporation was incorporated in 1981 and Is headquartered In Madison, Wisconsin.

2. Duke Energy Corporation, together with its subsidiaries, operates as an energy company in the United States. It operates through two segments, Electric Utilities and Infrastructure (EU&I) and Gas Utilities and Infrastructure (GU&I). The EU&I segment generates, transmits, distributes, and sells electricity in the Carolinas, Florida, and the Midwest; and uses coal. hydroelectric, natural gas, oil, solar and wind sources, renewables, and nuclear fuel to generate electricity. This segment also engages in the wholesale of electricity to municipalities, electric cooperative utilities, and load-serving entities. The GU&I segment distributes natural gas to residential, commercial, industrial, and power generation natural gas customers; and invests in pipeline transmission projects, renewable natural gas projects, and natural gas storage facilities. The company was formerly known as Duke Energy Holding Corp., and changed its name to Duke Energy Corporation in April 2006. The company was founded in 1904 and is headquartered in Charlotte, North Carolina.

3. American Electric Power Company, Inc., an electric public utility holding company, engages in the generation, transmission, and distribution of electricity for sale to retail and wholesale customers in the United States. It operates through Vertically Integrated Utilities, Transmission and Distribution Utilities, AEP Transmission Holdco, and Generation & Marketing segments. The company generates electricity using coal and lignite, natural gas, renewable. nuclear, hydro. solar, wind, and other energy sources. It also supplies and markets electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities, and

other market participants. The company was incorporated in 1906 and is headquartered In Columbus, Ohio.

4. OGE Energy Corp., together with its subsidiaries, operates as an energy and energy services provider that offers physical delivery and related services in the United States. It operates through Electric Company Operations and Natural Gas Midstream segments. The company generates, transmits, distributes, and sells electric energy. In addition, it provides retail electric service to approximately 889,000 customers, which covers a service area of approximately 30,000 square miles in Oklahoma and western Arkansas; and owns and operates coal-fired, natural gas-fired, wind-powered, and solar powered generating assets. OGE Energy Corp. was founded in 1902 and is headquartered in Oklahoma City, Oklahoma.

5. Entergy Corporation, together with its subsidiaries, engages in the production and retail distribution of electricity in the United States. The company operates in two segments, Utility and Entergy Wholesale Commodities. The Utility segment generates, transmits, distributes. and sells electric power in portions of Arkansas, Louisiana, Mississippi, and Texas, including the City of New Orleans; and distributes natural gas. The Entergy Wholesale Commodities segment engages in the ownership, operation, and decommissioning of nuclear power plants; and ownership of interests in non-nuclear power plants that sell electric power to wholesale customers, as well as provides services to other nuclear power plant owners. It generates electricity through gas, nuclear, coal, hydro, and solar power sources. The company sells energy to retail power providers, utilities, electric power co-operatives, power trading organizations, and other power generation companies. The company's power plants have approximately 24,000 megawatts (MW) of electric generating capacity, which include 5,000 MW of nuclear power. It delivers electricity to 3 million utility customers in Arkansas, Louisiana, Mississippi, and Texas. Entergy Corporation was founded in 1913 and is headquartered in New Orleans, Louisiana.

6. Eversource Energy, a public utility holding company, engages in the energy delivery business, The company operates through Electric Distribution, Electric Transmission, Natural Gas Distribution, and Water Distribution segments. It is involved in the transmission and distribution of electricity; solar power facilities; and distribution of natural gas. The company operates regulated water utilities that provide water services to approximately 241,000 customers. It serves residential, commercial, industrial, municipal and fire protection, and other customers in Connecticut. Massachusetts, and New Hampshire. The company was formerly known as Northeast Utilities and changed its name to Eversource Energy in April 2015. Eversource Energy was incorporated in 1927 and is headquartered in Springfield, Massachusetts.

7. Next Era Energy, Inc., through its subsidiaries, generates, transmits. distributes, and sells electric power to retail and wholesale customers in North America. The company generates electricity through wind, solar, nuclear, natural gas. and other clean energy. It also develops, constructs, and operates long-term contracted assets that consist of clean energy solutions, such

as renewable generation facilities, battery storage projects, and electric transmission facilities; sells energy commodities; and owns, develops, constructs, manages and operates electric generation facilities in wholesale energy markets. The company had approximately 33,276 megawatts of net generating capacity; approximately 90,000 circuit miles of transmission and distribution lines, and 883 substations. It serves approximately 12 million people through approximately 5.9 million customer accounts in the east and lower west coasts of Florida. The company was formerly known as FPL Group, Inc. and changed Its name to Next Era Energy, Inc. in 2010. Next Era Energy, Inc. was founded in 1925 and is headquartered in Juno Beach, Florida.

8. Pinnacle West Capital Corporation, through its subsidiary, Arizona Public Service Company, provides retail and wholesale electric services primarily in the state of Arizona. The company engages in the generation, transmission, and distribution of electricity using coal, nuclear, gas, oil, and solar generating facilities. Its transmission facilities include overhead lines and underground lines, and distribution facilities, as well as owns and maintains transmission and distribution substations. The company was incorporated in 1985 and is headquartered in Phoenix. Arizona.

9. Portland General Electric Company, an integrated electric utility company, engages in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. It operates six thermal plants, three wind farms, and seven hydroelectric facilities. As of December 31, 2023, the company owned an electric transmission system consisting of 1,254 circuit miles, including 287 circuit miles of 500 kilovolt line, 413 circuit miles of 230 kilovolt line, and 554 miles of 115 kilovolt line; and served 934 thousand retail customers in 51 cities. It also has 28,868 circuit miles of distribution lines. Portland General Electric Company was founded in 1889 and is headquartered in Portland, Oregon.

10. Evergy, Inc., together with its subsidiaries, engages in the generation, transmission, distribution, and sale of electricity in Kansas and Missouri, the United States. The company generates electricity through coal, hydroelectric, landfill gas, uranium, and natural gas and oil sources, as well as solar, wind, [and] other renewable sources. It serves residences, commercial firms, industrials, municipalities, and other electric utilities. The company was incorporated in 2017 and is headquartered in Kansas City, Missouri.

The 2022 10-Ks for Concentric's ten US comparators contain much more detailed information than the 'Yahoo' summaries. The 10-Ks make it abundantly clear how little they and Newfoundland Power have in common. To illustrate how much more detailed the 10-K information is, attached at Attachment A is a lengthy excerpt from Duke Energy Inc.'s 10-K (Information Item #9). The Duke excerpt illustrates just how dissimilar Newfoundland Power truly is from Concentric's U.S. comparators. (e.g. Duke Energy has a subsidiary captive insurance company that insures Duke Energy's other subsidiaries.)

2.6.4 Use of American Data Without Adjustment(s)

Concentric places greater weight on its North American proxy group, and makes no adjustments to account for differences in the U.S. and Canadian markets or for differences between Newfoundland Power and companies in its proxy groups. Concentric's approach is inconsistent with Order No. P.U. 13(2013) and Order No. P.U. 18(2016), as therein the Board held that differences in the U.S. and Canadian markets do exist and justify an adjustment of 50-100 basis points. In relation to Concentric's reliance on its North American proxy group and refusal to adjust for its use of U.S. data, cross-examination by Board Hearing Counsel produced this enlightening (and telling) exchange.

> *GREENE, KC:*
> *Q. And here if we could go to line 13. So, above that you do refer to the BC decision. Actually, we should scroll up to the top of the paragraph because it deals with how US data should be considered by the Board. So, there you do say that British Columba—in the British Columbia decision we just looked at, they didn't make an adjustment for US data, line 9 to 13. So, we just saw that the regulator also said that while you can look at US data, there is still a fair amount of discretion or judgement that must be used in how you assess the results.*
>
> *MR. COYNE:*
> *A. Yes, and the judgement they applied is that the North American Proxy Group was most appropriate, which only included a couple of Canadian companies because they were deemed to be most comparable. So, it was predominantly a US proxy group, but with appropriate Canadian companies that were added, and I think there were two that satisfied the Board's criteria in that regard.*
>
> *GREENE, KC:*
> *Q. Yes, but they went on to say that in determining the appropriate ROE there was still judgment to be exercised -*
>
> *MR. COYNE:*
> *Yes, there's judgement applied by the Board.*
>
> *GREENE, KC:*
> *Q. - about how to use the US data. So, if we now to go the second –*
>
> *MR. COYNE:*
> *A. How to--which companies to include in that case is what they were talking about.*
>
> *GREENE, KC:*
> *Q. As to the weighting of the--just go back to the US decision. I mean, I'm sorry, the BC decision we had up there. I guess it's an interpretation of the Board's words. "As for the weighting of the ROE results that's among the North American Proxy Group, as between Canadian/US utilities we find that to be largely a matter of judgement that is within our discretion." So, when I read that I understood that the Board, yes, they would--how I*

*interpreted it, and perhaps we should see if you interpreted it differently, is that even though they looked at American companies to see what the information was because it was useful data, they go on to say how they weighted the results from that group, it was to be a matter of judgement that was still within their discretion.*

*MR. COYNE:*
*A. Well, I think that sentence stands on its own, and I was going on our experience before the Board and the entire discussion where they talked--they're focused on which companies to include as arriving at their decision there is how I see the big picture, but I see what you're saying about their sentence...*

*GREENE, KC:*
*Q. When I read your evidence and the answer to the RFI, and now your rebuttal evidence, I took--what I took from it was that you were using the two recent decisions from Alberta and BC to support your opinion that the North American Proxy Group is the most relevant and reliable one for the Board to consider in setting the ROE for Newfoundland Power, and that in doing so, they didn't need to make adjustment for US data, that it was no need to do that. That's how I took what--and you use those two decisions to support your opinion which you have expressed since you have been the Cost of Capital Expert for Newfoundland Power.*

*MR. COYNE:*
*A. Well, our opinion is based on much more than that. We provide substantial evidence on the integration of North American markets, integration of the industries. So, we cite those as examples of how other regulators have approached this issue, but that's not the sum basis of our evidence that that's the right thing to do.*

*GREENE, KC:*
*Q. And I didn't mean to imply that. That you are using that as additional support for your position, you have expressed and to reflect the fact that the situation in Canada is evolving, that more regulators are going towards the use of American data.*

*MR. COYNE:*
*A. Yes, I think that's a fair characterization.*

*GREENE, KC:*
*Q. Sorry. That's what I had meant from before. Okay. So, if we can go now to the Alberta decision, which also was circulated last week, and I'd like this filed as an Information Item.*

*MS. GLYNN:*
*Q. The Alberta decision will be Information number 24.*

*GREENE, KC:*
*Q. So, I'd like to go to page 22, and if we could go up to, yes, the paragraph 103. There reading from that, "While the Commission finds that the US companies have higher*

*business risks than the Alberta utilities for the purpose of establishing the comparative group, the Commission accepts the utility's evidence that it is appropriate to include US holding companies," and they go on to give the reasons for doing so, which I won't read, but then they go on in paragraph 104 and say, "After considering the evidence presented in this proceeding, the Commission acknowledges that the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in the various financial models. And then we go on down. They go on to say that, "The Alberta utilities at the low end of the range of risk presented in comparator groups, and accordingly the Commission retains the view as expressed in the 2018 generic cost of capital decision, that a significant amount of judgement must be applied by the Commission when interpreting data from representative utilities to establish the ROE required by investors in the Alberta utilities." So, again, there was-- do you agree, Mr. Coyne, that there was an acknowledgement by the regulator there that again a significant amount of judgement had to be applied in interpreting the data even though they had considered American companies, or the North American Proxy Group, for the purposes of analysis?*

*MR. COYNE:*
*A: Yes, I think that statement stands for itself...*

*GREENE, KC:*
*Q. Yes. So, the reason to refer to these decisions is the fact that even though American data was considered in the two recent decisions, there was also acknowledgement that there's still a significant amount of judgement that has to be applied to how the data is used. And, in fact, if we go through them, we may go through a couple of how Alberta considered your recommendations with respect to the market risk premium use of adjusted betas to see that they also exercised their judgement and how that was going to be applied to the proxy, proxy group that included American companies.*[52]

Any distortion(s) occasioned by the unadjusted usage of data concerning the ten companies in Concentric's U.S. proxy group would necessarily spill over into Concentric's North American proxy group because those U.S. companies comprise about 70% of the fourteen companies included by Concentric in its North American proxy group.

2.6.5 Beta and CAPM Analysis

Concentric in its Written Rebuttal takes issue with Dr. Booth's CAPM analysis, particularly with respect to beta.

*Q. What is your most important area of disagreement with Dr. Booth's CAPM analysis?*

*A. The most important area of divergence in our respective CAPM analyses is with respect to beta. This is what drives the unreasonably low return estimate that Dr. Booth uses to support his ROE recommendation for Newfoundland Power.*

[52] June 19, 2024 Transcript (page 83, line 19 to page 94, line 1)

*Q. Please explain the disagreement over beta in the CAPM analysis.*

*A. Dr. Booth uses a range of beta coefficients from 0.50 to 0.60 for regulated utilities based on his judgment that utilities are low risk companies that investors value for their stability and dividend payments during economic downturns. Although Dr. Booth has increased his range for beta in recognition that betas have increased in recent years for electric utilities, his estimated beta coefficients are not based on current market data for companies that are compatible in risk to Newfoundland Power. On the other hand, as described in our Report, Concentric uses five-year weekly betas from Bloomberg and Value Line for our Canadian and U.S. proxy group companies...*[53]

As Concentric considers Dr. Booth's use of beta the "*most important area of divergence in their respective CAPM analysis,*" a thorough review of Dr. Booth's fulsome response to Concentric's criticism is warranted.

*Relative risk beta, Mr. Coyne uses current values and in fact, one RFI asked me why don't I use current values? That's because current values are not current values. They're simply the most recent estimates generally over the past five year period. The last five-year period has been COVID, a massive Central Bank intervention. That's a valued estimate if we think there's going to be another COVID and another massive Central Bank intervention in the future. I don't think we're anticipating another COVID 19 over the test years...*

*Betas in the US versus Canada. Canada is a different market to the United States. The betas for the gas companies in the United States are quite similar to what they are in Canada. For the last 30 years betas for electric companies in the United States have been significantly higher than the Canadian companies in the utility index, to the tune of about 0.2. 0.2 times the 6 percent market risk premium means a different of 1.2 percent in the allowed ROE. I haven't seen anything to demonstrate that the betas of US utilities, electric utilities can be used in Canada without exercising judgment. What about the Canadian sample? I've been cross-examined because I used the words "forced to rely upon or use American data". I would prefer not to use American data, it's a different country with different laws, different regulations and different capital market conditions. We're forced to look at the United States. A lot of the Canadian companies simply don't exist anymore...*

*...I look at the Americans, now I like to see Mr. Coyne in the audience because I have to say he gets me really annoyed, really annoyed. He says things that are simply not true. And I say that with great trepidation because I'm sure Mr. O'Brien is going to ask me questions. He said, and it's only his rebuttal testimony if somebody wants to maybe look at that, he said Professor Booth is judgment, judgment, judgment. My beta estimates are not judgment. My beta estimates are the statistical estimates without any exercise of judgment. I present those to the Board because they can look at them to see whether they trend towards one or what the values are, and I go out and get other beta estimates that*

[53] May 28, 2024 Concentric Written Rebuttal Testimony (page 27, line 7 to page 28, line 6)

*are in the capital market. RBC, the Royal Bank of Canada, does not use my beta estimates. They produce their own beta estimates or they provide them to their clients. Yahoo, they use Compustats, Standard and Poor's, they're not my beta estimates. CFRA, it's interesting to think who they are. After the analyst scandal in the early 2000s, they were required to put money providing independent research reports and CFRA is one of those independent research reports. They're not my betas. Reuters, I have [no] influence over what Reuters whatsoever, now their betas, I don't know where they come from, but they're in the capital market. So what I do is I provide my beta estimates and I benchmark them relative to Reuters, Thomson Reuters, one of the biggest companies, RBC, biggest bank in Canada, Yahoo, one of the major providers with Standard and Poor's of data. CFRA, an independent research firm. I've benchmarked by betas against their betas and lo and behold they're pretty similar. There are differences because they used slightly different techniques, and then finally I started looking at the Global Mail. I read the Global Mail is they claim to be Canada's premier newspaper, they report on business. They produce beta estimates. Now they have beta estimates over three years, but they're there, they're not my judgment. They are the statistics, those are the numbers that are in the capital market and I really get annoyed with Mr. Coyne says, well it's Booth's judgment. It's not my judgment. These are what are in the capital market.*

*What about the US? Same organizations estimate the betas for the US and these are the current estimates for the betas for the year of the United States and they're about 0.6 and there's no question they have increased over the last couple of years, but when we look at this, had they increased over a long period of time? Well if you look at the last little blip at the end of that 2018 until now, they've increased, but they're not as high as they were in 2007. They tend to go up and down with the state of the capital market. Beta adjustment, Mr. Coyne is fond of saying that I'm the only person that uses unadjusted betas and it's standard to use adjusted betas. That is absolutely, absolutely nonsense, that is incorrect. What Marshall Blume did was he estimated the beta in time period T and then he looked at how does that compare with the beta of 5 years earlier and four years and three years, he used different time periods. And you have to go back to long periods of time to avoid using the same datapoint in both of the estimates, so you have to make sure that you don't use overlapping betas. So this is what we call a partial adjustment model. How do the current beta compare to five years ago or three years ago and is it adjusting in any way to its true value, because you can calculate the true value simply by setting beta T equal to beta T minus 5 and then solve it. And if you do that, which is what Marshall Blume did, you get .33 for the Blume adjustment and a two thirds adjustment on the past value. That's not controversial, in fact, it's a truism...*

*So the question the Board needs to ask is if they were told the beta for a utility was 0.5, do they say I know nothing about that 0.5, I know nothing about the utility, I will adjust it towards 1? Well I certainly wouldn't because I've been looking at utilities for the last 35, 38 years. I know they're low risk and I would not be surprised in the beta was equal to 0.5 or 0.4, so when you look at this, you say well how do utility betas adjust? Combola and Kahl, for a long time was—the gold standard they actually looked at US utilities and they said they don't adjust towards 1, they adjust towards their mean, which is what you might expect. If you think the beta for a utility should be 0.5 and you come up with 0.2,* *then you say, well, I don't think it's equivalent to the overall risk in the market, but I think it's low, so I'll adjust it towards what I expect it to be, around 0.5. More recently Michefielder and Theodossiou, they did the Blume adjustment for utilities in the United States. I'm not going to read the whole quote, anyone can read that quite, absolutely no evidence whatever, no matter what time periods they used, the types of betas they estimated, no statistical evidence of any utility betas adjusting towards 1. This is absolutely bulk standard. There is no empirical evidence whatsoever of utility betas moving towards 1 with a Blume adjustment. It assumes we know absolutely nothing about the utility. Now, Mr. Coyne says, well, Bloomberg betas use adjustment towards 1. That's not correct. Bloomberg is a data provider. The betas you get from Bloomberg if you estimate using their data depends upon the values you put in, what you want to estimate. If you want to estimate Blume adjusted beta, you can estimate it. If you want to estimate betas, what is called unadjusted betas, the betas that I estimate, you can estimate those as well. And in fact, on their website you can do a quick check, just enter Bloomberg betas and they will tell you Bloomberg betas and they will tell you exactly how they do their betas. On their website they report Blume adjusted betas and they report unadjusted betas. Saying that Bloomberg betas are adjusted betas is absolutely incorrect. I could just as well have reported Bloomberg's unadjusted betas and said these are Bloomberg betas. They're not. They're my choice of using the data in Bloomberg to come up with a beta. Value Line, Value Line surveys all the American stocks and they do have a one-age crib sheet which includes adjusted betas because they're looking at all the stocks in the market. They haven't done any research on utility stocks independently of their beta adjustment. They used the Blume adjustment. That is a paid subscription service that primarily looks at US...*

*DR. BOOTH:*
*A. No, I think it's the job of a witness to provide impartial, objective evidence to the Board and lay out all of the information so the Board can reasonably use that data to form an opinion and that the Board can see where the data is before the analyst exercises their judgment. We all exercise judgment, but the question is: what's the starting point? What is the data? And I don't think Mr. Coyne has done that.*

*MR. O'BRIEN:*
*Q. Okay. You have?*

*DR. BOOTH:*
*A. Absolutely. I presented not just my estimates, I presented all these other estimates from people. I presented more independent estimates of the market risk premium and betas than has Mr. Coyne, a lot more...*

*...That's something that I've tried to emphasize. And also to be fair in response to other witnesses, I estimate my betas, but I now have RBC betas, and I have all these other betas, so that the judgment component is--I mean, when I say judgment I mean the betas are the betas, are what they are. They're empirical estimates. I use the same software to develop those betas as Bloomberg or anybody else. So, that's what the data shows. I have come up from 0.45 to 0.55, to 0.5 to 0.6. So, there has been an increase in my beta*

*estimates. They're still not adjusted because I can't find any evidence whatsoever for a beta adjustment towards 1, but I still do think we should adjust beta estimates based upon judgment.*

*MR. O'BRIEN:*
*Q. Your estimates are significantly below the raw data presented by Mr. Coyne and Concentric.*

*DR. BOOTH:*
*A. That I don't understand because what Mr. Coyne is saying is not just that Booth uses judgment, which I don't, but his estimates are too low. The Royal Bank of Canada's estimates are too low. CFRA's estimates are too low. The Globe and Mail's estimates are too low, and Yahoo, S&P's estimates are too low. So, it's like everybody else is too low, but [believe] my betas.*

*Mr. Coyne hasn't provided, as far as I can see, apart from the beta, the adjusted betas, any corroborating evidence for his betas. I do note that he tends to use weekly betas, and I present evidence—and again, the only published research on this area that there's a time horizon over which you estimate the betas reduces, so instead of monthly they use weekly. then the estimates for thinly traded stocks go down, and for thickly traded stocks go up, and the reason for that is straightforward. Thinly traded stocks don't trade, and if they don't trade, the prices stay exactly the same. So, the estimate of their volatility goes down so they look less risky, where thickly traded stocks, they trade all the time, and you got all this information about what's going on.*

*So, since they have to add up to 1, it means the thickly traded stocks, the beta estimates, are over-estimated. So, that is empirical evidence. I don't use weekly betas because everybody in academia has access to the same data tapes, and for the last 30 or 40 years we've used the Center for Research and Security Prices which has monthly beta on stock prices and returns.*

*Mr. Coyne uses Bloomberg, but these series weren't available 10, 20, years ago. A lot of the data that's available now simply wasn't available when I started testifying, and he uses weekly beta, weekly beta. I mean, this has been an issue before the Alberta Utilities Commission. Why is Mr. Coyne's beta estimates so high. One is because their adjustments are regarded as inappropriate. The other is because he uses weekly betas and not monthly betas. And if you use six monthly betas, i.e. betas that are estimated over six monthly periods, they've been even lower because the frequency with which you estimate the beta has an impact on the value that you get out of them, and it's not an accident, and most of the utility witnesses have gone to weekly betas, and almost all academics continue to use monthly data….*

*DR. BOOTH:*
*A. It just looks at price changes. They don't look at dividends, and when you include dividends, as you do, for the overall rate of return, that tends to moderate the beta estimates; whereas Bloomberg I know uses price changes. It says so on their webpage.*

*But I can't understand, if that is correct, and I haven't looked at Bloomberg, and I don't have a Bloomberg, I do not understand why those estimates are so different from public market beta estimates. And as I said, you can check Bloomberg betas on the internet and you can find out how they do— estimate their betas, and they report both Bloom adjusted betas, and they report unadjusted raw betas. I cannot understand how their estimates disagree from all the other public market –...*

*DR. BOOTH:*
*A. Yeah, I don't understand that to be absolutely honest because it's not--it's not consistent with the data in the Centre for Research and Security Prices. It's not consistent with the data in the Toronto Stock Exchange database. It's not consistent with all of the betas produced by independent authorities. So, it has to be that they use weekly betas, estimated the data, and you use the short time period, and probably the short time period is you're saying that whatever happens in that short time period is going to happen in the future. So, it would have to be covering the period of the last 36--the last three years if you're using three year weekly betas, and then you must then be assuming that whatever happened in the last three years, or from--I think somewhere uses January 2020, is going to repeat in the future, which means--which means that you're COVID and the rising interest rate period over the last 18 months is going to happen again in the future.*

*MR. O'BRIEN:*
*Q. So, that's your assumption?*

*DR. BOOTH:*
*A. No, I'd say that is--that is not my assumption, that's what it is.*[54]

In summary, both Dr. Booth's approach to, and his estimate of beta are well founded.

## 2.7 Newfoundland Power's Weighted ROE

In her opening statement, Paige London explained that Newfoundland Power's ROE must be considered in conjunction with its equity ratio (i.e. a utility's weighted ROE being its ROE multiplied times its equity ratio). A Concentric graphic [55] (Figure 1 of Concentric Written Rebuttal Testimony) depicting various weighted ROEs demonstrates that Concentric's recommendation of a 9.85% ROE and 45% equity ratio would cause Newfoundland Power to become the potentially relatively most profitable Canadian electric utility, and relatively more profitable than all but one Canadian gas utility. At its current 8.5% ROE and 45% equity ratio, Newfoundland Power sits just above the profitability midrange for Canadian utilities. In that regard, Board Hearing Counsel posed questions to Ms. London.

[54] June 29, 2024 Transcript (page 17, line 24 to page 18, line 11; page 21, line 18 to page 22, line 16; page 23, line 20 to page 27, line 10; page 28, line 3 to page 30, line 18; page 58, line 7 to page 59, line 1; page 207, line 17 to page 210, line 24; page 213, line 9 to page 214, line 2; page 215, line 7 to page 216, line 12)
[55] May 28, 2024 Concentric Written Rebuttal Testimony (page 10, line 1 to line 3)

*GREENE, KC:*
*Q. And I believe in your opening statement, you said that the ROE must be considered hand in hand with the capital structure. Is that correct?*

*MS. LONDON:*
*A. Yes.*

*GREENE, KC:*
*Q. So, now I'd like to go to how overall the ROE and the capital structure of Newfoundland Power compares to other utilities in Canada, and here if we go to Dr.* (sic) *Coyne's rebuttal evidence, page ten. And when look at this Figure 1, it's very helpful because it talks about the weighted ROE for Canadian utilities and we look at the equity in the capital structure, whether it's 45 percent for you, times the approved ROE of 8.5 percent. So, if we look at the grey bar that's kind of three quarters of the way over, and we see at the bottom, Newfoundland Power. So, here we see the grey bar, the current – where you currently are, you're about 3.8 weighted ROE, which is better than Fortis Alberta, Hydro One, Nova Scotia Power, other Ontario Electric Distributors, Maritime Electric. So, right now, you're more than halfway up the pack, the group. Then we look at where your recommendation brings us, which is the green bar, Concentric's recommendation. That will put you the highest of any electrical utility in Canada. So, I would say, if your recommendation is approved, not only would you be a comparable risk, you would be probably the best electrical utility to invest in. So, in looking at this figure, which as I said I find helpful to look at another one of the requirements of the fair return standard, which is the comparable investment. Can you explain or in your opinion, the current ROE and the current 45 percent does provide Newfoundland Power with meeting the requirement that investment in Newfoundland Power be comparable to other electrical utilities of similar risk. Is that correct?*

*MS. LONDON: A. When it comes to the comparability and risk, that's something that I will have to defer to Concentric. The comment that I would make is Newfoundland Power's weighted return on equity is reflective of our risk profile and that is part and parcel of our 45 percent common equity that's been in place for a long period of time.*[56]

While Concentric produced the graphic to illustrate the comparative effect on Newfoundland Power's weighted ROE that fully implementing Dr. Booth's recommended 7.7% ROE and 40% equity ratio would have, it is readily apparent that partial implementation of Dr. Booth's recommendations could occur without Newfoundland Power's relative profitability (i.e. its weighted cost of capital) being significantly altered relative to that of other Canadian electric utilities.

Table 1 below builds on data in Figure 33 of Concentric's Cost of Capital report.[57] It shows the equity ratios and regulatory-authorized ROEs for various utilities and gives the implied weighted ROE (which is simply the ROE multiplied by the equity ratio). As shown, if Newfoundland Power's

[56] June 17, 2024 Transcript (page 139, line 17 to page 141, line 23)
[57] November 7, 2023 Concentric Cost of Capital Report (page 55, line 16)

proposed ROE were approved then its weighted ROE, at 0.04433 (or 4.433%) would be the highest among the Canadian utilities shown. It would, like all the Canadian utilities, be less than the US average but, as discussed earlier, direct comparison with the US is not appropriate.

***Table 1***
***Comparison of Allowed Equity Ratios / Authorized ROEs / Weighted Cost of Capital***
***(using data in Concentric's Figure 33)***

| Operating Utility | Deemed Equity Ratio | Authorized ROE | Weighted ROE |
|---|---|---|---|
| Newfoundland Power (current) | 45.0% | 8.50% | 0.03825 |
| Newfoundland Power (proposed) | 45.0% | 9.85% | 0.04433 |
| | | | |
| Alberta Electric Utilities | 37.0% | 8.50% | 0.03145 |
| FortisBC Electric | 41.0% | 9.65% | 0.03957 |
| Ontario Electric Utilities | 40.0% | 9.36% | 0.03744 |
| Maritime Electric | 40.0% | 9.35% | 0.03740 |
| Nova Scotia Power | 40.0% | 9.00% | 0.03600 |
| | | | |
| Canadian Electric Average | 39.6% | 9.17% | 0.03631 |
| | | | |
| US Electric Utility Average | 51.6% | 9.66% | 0.04985 |

Next, Table 2 shows how reducing Newfoundland Power's ROE, and holding its equity ratio at 45%, affects it weighted ROE. As shown, if the ROE were 8.4% , Newfoundland Power's weighted ROE would be 0.0378. That would place it second highest among the Canadian utilities in Table 1. An ROE of 8.3% would put its weighted ROE very close to those of Maritime Electric and the Ontario utilities. At a ROE of 8.07%, it would still have a weighted ROE (0.03632) equal to the Canadian average (0.0361). This suggests a choice in the range of 8.1% and 8.3% would be reasonable.

***Table 2***
***Various Scenarios Based on a Lower Authorized ROE***

| | | | |
|---|---|---|---|
| Newfoundland Power | 45.0% | 8.40% | 0.03780 |
| Newfoundland Power | 45.0% | 8.30% | 0.03735 |
| Newfoundland Power | 45.0% | 8.20% | 0.03690 |
| **Newfoundland Power** | **45.0%** | **8.10%** | **0.03645** |
| **Newfoundland Power** | **45.0%** | **8.07%** | **0.03632** |
| Newfoundland Power | 45.0% | 8.00% | 0.03600 |

While Concentric provided Figure 1 to illustrate the comparative effect on Newfoundland Power's weighted ROE that fully implementing Dr. Booth's recommended 7.7% ROE and 40% equity ratio would have, it also vividly shows that partially implementing Dr. Booth's recommended downward adjustments of the ROE and/or equity ratio would result in Newfoundland Power's weighted ROE remaining above that of other Canadian utilities.

When concluding her questioning of Dr. Booth, Board Counsel succinctly summarized the circumstances the Board routinely faces when determining the cost of capital issues.

> *GREENE, KC:*
> *Q. So I've come to my last question, you have said in your evidence and also in cross examination by Mr. O'Brien that you're somewhat frustrated in having appeared for 38 years, I believe you said, and not having your opinion understood and accepted. I was going to say I think I've been here almost as long involved in regulatory proceedings, for several years for a utility and in the last 13 as board hearing counsel and what the commissioners may and board hearing counsel may find difficult to understand or frustrating is when they're looking at these things, we see significantly different recommendations coming from experts, often using the same methodologies. I believe you have agreed that significant discretion and judgment, I'll call it discretion, it's judgment, has to be used by the experts and you can see it's also used by the regulatory boards when they are presented with what can appear to be extreme recommendations. What I mean extreme, I mean one is very, is much lower than the other and the utility cost of capital expert tends to be higher than what ends up being accepted by the regulator; whereas the Consumer Advocate expert's opinion doesn't seem to be accepted either, so what is the Board to do with that....*[58]

In deciding what "*the Board is to do with that,*" the Board should adopt a practical approach that is fair to Newfoundland Power and its customers.

The cost of capital experts here position a fair ROE as being as low as 7.70% to as high as 9.85%; the gap between the two being 215 basis points.

Unsurprisingly, Newfoundland Power urges that its longstanding 45% equity ratio – still the highest in Canada - be maintained, while Newfoundland Power also wants the Baord to increase its allowed ROE by 16% (from 8.50% to 9.85%). Acceding to that request would increase Newfoundland Power's weighted cost of capital by 16%, and also thereby its profitabilty by 16%. In the attendant circumstances, a 16% increase in Newfoundland Power's ROE and profitability would be unfair and an affront to Newfoundland Power's customers. It is time for the Board to send a message to Newfoundland Power:

"It is no longer business as usual."

In relation to dertermining the cost of capital, the Board must do so prudently, using a principled approach based on the evidence before it. The Board here can – and should - maintain an aproved equity ratio of 45% while reducing the allowed ROE to 8.10%. The rationale follows.

[58] June 21, 2024 Transcript (page 98, line 25 to page 100, line 3)

Maritime Electric, an electric utility not dissimilar to Newfoundland Power, has an approved equity ratio of 40.0%, and an allowed ROE of 9.35%, giving it a weighted cost of capital of 0.03740.

Nova Scotia Power Inc., an electric utility not quite as similar to Newfoundland Power (but far more similar than Duke Energy, et al.), has an approved equity ratio of 40.0%, and an allowed ROE of 9.00%, giving it a weighted cost of capital of 0.03600.

If Newfoundland Power were to maintain its 45% equity ratio, which is seemingly the matter of utmost importance to it, then a ROE derived from a weighted cost of capital equal to the average of the weighted costs of capital of Maritime Electric and NSPI would be 8.16% (i.e. 0.03740 + 0.03600 = 0.0367 / 0.45 = 8.15% ROE).

Analagously, a ROE derived using a 45% equity rato and Concentric's Canadian Electric Average of 0.03631 weighted cost of capital is 8.07% (i.e. 0.03631 / 0.45 = 8.07% ROE).

Not coincidenatally, these derived ROE figures of 8.15% and 8.07% are very close to the 8.13% upper end of Dr. Booth's suggested range of 7.28% to 8.13% for a fair ROE.

Also not coincidentally, Newfoundland Power's own actuary expert (Mercer (Canada) Ltd.) concurs with Dr. Booth's opinion – within a few basis points - as to the adjusted equity market return. Dr. Booth's viva voce testimony reads:

> *...How does this translate into a per share value? But basically we're looking at 7 percent plus, 8 percent, for the equity market. And as it gets more difficult to look at individual utilities, I've looked more at what constrains are judgment which is the overall expectation for the capital market. Does Newfoundland Power accept this? The answer is that they do. They have a defined benefit pension plan. In answer to an information request, I asked them to tell us what assumptions does Newfoundland Power use in their pension plan in terms of the equity rate of return and they reported 3 percent for bonds, 7.1 percent for equities, 4.1 percent risk premium and then they immediately, I think immediately, I don't know exactly the timespan, but they asked Mercer, their consultant, to convert these long run returns to a one year return, which is what we tend to use when we calculate risk premiums, and that increases the equity return from 7.1 to 8.63. That's exactly the adjustment that I made in the report to the TD Bank returns. It's a standard adjustment to convert a long-run rate of return to a short-run rate of return, a one-year rate of return.*
>
> *So, now, Newfoundland Power, their actually is exactly the same as where I am. No difference whatsoever. In fact, I've done a lot of work for some of the biggest pension plans in Canada and they have to work out exactly the same problem, what do the markets expert for the rate of return, for our pension plan and the flip of that is what does the corporation have to think about in terms of return for this cost of capital. They're two sides of the same coin. The supply and the demand for the debt.*[59]

[59] June 20, 2024 Transcript (page 16, line 7 to page 17, line 23)

> *So I've tried to go out of my way, particularly over the period since 2009 when we got, after the financial crisis to include more and more, as much data as possible on independent views of what's going on in the capital market. And of what's going on in the capital maAnd as I said, Mercer, Newfoundland Power's actuary, their estimate of the Canadian equity market return is within a few basis points, exactly the same as mine, and if Mercer and Newfoundland Power accepts Mercer's judgment that the adjusted market return from 7.1 percent to 8 point something or another to make it consistent with regulatory practice is in the 8s, if that has been accepted by Newfoundland Power, it's Mercer's judgment, it's exactly the same judgment as mine, how can you give Newfoundland Power 9 point whatever it is they're asking for, 9.85 percent when their own actuary is telling them that the long-run return on the equity market is 8 point four something or other. You now, sooner or later you'll have to listen to, not just the academic finance experts, but the actuaries and the people actually putting money behind their estimates.*[60]

## 2.8 Appropriateness of a Flotation Adjustment

Dr. Booth recommends that the Board consider questioning the advisability, and legality, of the Board routinely and automatically including a floatation adjustment of 50 basis points, when Newfoundland Power incurs no such expense.

## 2.9 Band Width

The Board's policy has been to allow a +/- 18 basis point band about the regulated rate of return on rate base. If Newfoundland Power earns a rate of return on rate base of more than 18 basis point over the regulated rate then the excess goes to the Excess Earnings Account, and the disposition of such excess earnings is determined by the Board. If the actual rate of return on rate base is greater than the regulated rate of return on rate base (and this is due to higher earnings) but less than 18 basis above it, then those earnings are retained by Newfoundland Power so its actual ROE can be higher than set by the Board. At a 45% equity ratio, if the actual ROE is 40 basis points (0.40%) above the "allowed ROE" then those extra earnings go to Newfoundland Power.

Dr. Booth's report points out that Newfoundland Power has benefitted from this arrangement. He writes:

> *The following graphs NP's allowed versus actual ROE since 1990 as provided in CA-NP-079...NP has been allowed a band around its rate of return that translates into approximately +/- 0.40% on its ROE. The graph indicates that NP has consistently earned its allowed ROE with an average "excess" of 0.25% over this very long period. However, between 1990 and 1995 it underearned in five years mainly due to severe weather and a reassessment by CRA. Since then, NP has not under earned in a single year, and since 1995 its over earning has averaged 0.43% with the CRA reassessment in the early 2000's accounting for a significant amount of the overearning in those years.*

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[60] June 21, 2024 Transcript (page 105, line 12 to page 106, line 13)

> *Excluding those years, since 2003 NP has still over earned by 0.30%, or near the top of the 0.40% band.*[61]

In summary, the evidence establishes that: in every single one of the 26 consecutive years from 1998 to 2023, Newfoundland Power earned a higher rate of return on equity than its approved rate; and since 2003 Newfoundland Power has over earned by 0.30% (i.e. near the top of the +/- 0.40% band) For the longer period, Dr Booth puts the excess at 0.25%. It is worth emphasizing that a 0.25% excess does not lead to any of the extra going to the excess earnings account, which would be potentially available to benefit consumers.

A tightening of the band around the regulated rate of return on rate base is needed. Otherwise, given the long history of extra earnings, the existing band may continue to allow a de facto rate of return on equity than set by the Board.

Reducing the band from +/-18 basis points to 6 would be reasonable. It would give the utility the incentive to try to earn more (through cost cutting), but the extra, in terms of ROE, would be 0.133%.[62] There is a risk, however, that the other component of the rate of return on rate base, namely the debt cost, could be the cause of its increase. Therefore, in fairness, any required contributions to the Excess Earnings Account could be limited so that the contributions would not reduce the ROE to less than the approved rate.

## 2.10 Automatic Adjustment Formula

While the parties agreed to a continuation of the suspension of the automatic adjustment formula, questions about the subject were nevertheless posed during the viva voce hearing. Dr. Booth offers this perspective.

> *DR. BOOTH:*
> *A. Do I recommend the Board put in an automatic adjustment formula? To be honest, I'm indifferent. If your decision is to have three-year GRAs, the first two years of that three-year period are done. So, we're talking about putting in an automatic adjustment formula for the third year. I don't see great benefit from that. If you want to reap economic efficiencies in regulating Newfoundland Power, you have to say we're going to put in a formula and we don't want to hear ROE testimony in three years time or four years time or five years time. It's indefinite, the way the NEB formula was... I agreed with Newfoundland Power to suspend the ROE formula. I don't think the Capital Asset Pricing model has worked without the application of judgment since 2009 and I agree with Mr. Coyne on that. We are getting close. The decision on automatic ROE formula depends upon whether the Board makes a decision for regulator efficiency and not have ROE hearings and then rely upon NP to come -- Newfoundland Power to come back and say the results aren't satisfactory...So, I have no objection to you putting Newfoundland Power back on an automatic adjustment formula. It's a question the Board has to deal with that is the regulatory efficiency worth it for one year in the third of a test year, if it*

[61] April 2024 Evidence of Dr. Laurence Booth (page 97, line 7 to page 97, line 2)
[62] 6 basis points divided by a 45% equity ratio gives 13.33 basis points

> *plans to have a GRA for Newfoundland Power in three years time. And that's not a thing that I can answer. All I've done in m Appendix E is lay out the history so it's got the guidance and the understanding as to how we got to this date and why the automatic ROE adjustment models were suspended.*[63]

Dr. Booth comprehensively and cogently discusses where the relevant captal markets and national economies have been and presently are. He also discusses the simiarities and differences between regulated utilities in Canada and the U.S., and compellingly demonstrates why U.S. data, when utilized by Canadian utility regulators, should be applied with appropriate modiification(s) based on the exercise of skilled judgment.

### 2.11 Recommendations on Cost of Capital

The following recommendations reflect the preceding assessment. They would be fair to the consumer and Newfoundland Power.

***Recommendation: If the Board decides to allow Newfoundland Power to maintain an equity ratio of 45% then the allowed ROE should be set at 8.15%. A higher allowed ROE should entail a lower equity ratio.***

***Recommendation: The band around the regulated rate of return on rate base should be set at +/- 6 basis points but with any contributions to the Excess Earnings Account capped at the point where further contributions would cause Newfoundland Power's ROE to be less than the allowed rate.***

## 3. OPERATING EXPENSES

### 3.1 Recent Trends

The GRA's revenue requirements for 2025 and 2026 include proposed operating expenses of $81.903 million and $84.940 million, respectively; (see GRA, Exhibit 7 where these are listed as "operating costs.")

Operating expenses are closely related to "gross operating costs." Operating expenses equals gross operating costs plus "amortization cost of CDM programs," minus "GEC" (general expenses capitalized). Detailed breakdowns of gross operating costs are given in the GRA's Exhibits 1 and 2.

Table 3 gives the trend in operating expenses from 2023 to 2026.

***Table 3***
***Operating Expenses 2023 to 2026 (millions)***

| | Operating Expenses[64] | Year over Year Increase |
|---|---|---|

[63] June 20, 2024 Transcript (page 49, line 17 to page 50, line 6; page 50, line 21 to page 52, line 7; page 52, line 25 to page 53, line 12)

[64] Sources: For "Forecast," see NLH-NP-039 Table 1. For "Proposed" for 2025 and 2026, see GRA Volume I, Exhibit 7.

| | | |
|---|---|---|
| 2023 Actual | $73.913 | 7.3% |
| 2024 Forecast | $78.775 | 6.6% |
| 2025 Proposed | $81.903 | 4.0% |
| 2026 Proposed | $84.940 | 3.7% |

The figures in Table 3 show that Newfoundland Power's proposed 2025 and 2026 operating expenses lead to a 4.0% increase and a further 3.7% for those years, respectively. Those increases come after large increases in 2023 (7.3%) and 2024 (6.6%).

Also, it is worth looking back on Newfoundland Power's actual spending relative to test-year amounts. Table 4 provides that comparison for 2022 and 2023. In each year, actual spending exceeded the test-year by a significant proportion.

***Table 4***
***Operating Expenses (millions): Test Year vs. Actual***[65]

| | Test Year | Actual | Excess of Actual over Test Year |
|---|---|---|---|
| 2022 | $64.996 | $68.869 | 6.0% |
| 2023 | $70.725 | $73.913 | 4.5% |

That prior record and now the proposed increases are not favourable to customers and is suggestive of weak cost control. Action is needed to restrain the growth in operating expenses.

### 3.2 Cost Growth

Table 5 compares that expenditure growth to inflation, as measured by Canada's Consumer Price Index (CPI) as well as by the GDP deflator. It shows that in each year from 2023 to 2026, Newfoundland Power's operating expenses growing by more than the forecasts for each of the two measures of inflation. Over the full period, operating expenses' cumulative growth is 23.4% whereas cumulative inflation (11% as measured by the CPI, and 8.8% according to the GDP deflator) is less than half that.

***Table 5***
***Growth in Operating Expenses compared to Inflation***[66]

| | Growth in Operating Expenses | Inflation (CPI) | Inflation (GDP Deflator) |
|---|---|---|---|
| 2023A | 7.3% | 3.9% | 1.5% |
| 2024F | 6.6% | 2.5% | 2.7% |
| 2025F | 4.0% | 2.2% | 2.2% |

[65] NLH-NP-039, Table 1

[66] Annual growth rates for operating expenses are from Table 3. Inflation forecast are from TD Economics. TD Economics, Latest Forecast Tables, June 2024; https://economics.td.com/ca-forecast-tables#lt-ca. The inflation forecasts are consistent with the Bank of Canada's targeting of a 2% inflation rate, and they are very similar to forecasts given in the federal government Budget 2024, see Annex 1:Details of Economic and Fiscal Projections, Table A1.9.

| | | | |
|---|---|---|---|
| 2026F | 3.7% | 2.0% | 2.1% |
| Cumulative | 23.4% | 11.0% | 8.8% |

The GRA is for 2025 and 2026, and in those years, the growth in operating expenses is not only higher than inflation but builds on a 6.6% increase in 2024, preceded by 7.3% in 2023. Yet, there is no evidence in the GRA that the cost pressures on Newfoundland Power are any greater than those faced by other enterprises and by consumers.

If operating expense is expressed on a per-customer basis, the story is much the same, as shown in Table 6. In each year, the growth in operating expenses per customer is substantially higher in each year than the inflation rate (as given in Table 5).

***Table 6***
***Growth in Operating Expenses per Customer: 2023-2026F***

| | Operating Expenses (millions) | Number of Customers[67] (thousands) | Operating Expenses per Customer | Growth Rate |
|---|---|---|---|---|
| 2023A | $73.913 | 275.5 | $268 | 6.7%[68] |
| 2024F | $78.775 | 276.4 | $285 | 6.2% |
| 2025F | $81.903 | 277.5 | $295 | 3.6% |
| 2026F | $84.940 | 278.4 | $305 | 3.4% |

In its GRA and various responses to RFIs, Newfoundland Power's has pointed to productivity improvements and efficiencies that it has undertaken. Clearly, those efforts have failed to limit increases in operating expenses to something less than the overall rate of inflation in the economy. Newfoundland Power has its own company inflation rate so the most that can be said is that without the claimed efficiencies, the growth in operating expenses would have exceeded the general rate of inflation by an even great margin than illustrated in Table 5. That is not nearly good enough. There is no evidence that Newfoundland Power faces greater inflationary pressures than consumers and other businesses. Action is needed to incentivize the company to aggressively reduce the growth in its operating expenses. The proposed operating expenses should not be approved. Newfoundland Power should at least keep cumulative growth in per-customer operating expenses in line with cumulative inflation.

The forecast for CPI inflation gives a cumulative rate from 2024 to 2026 of 6.9% and for the GDP deflator the cumulative rate is 7.2%.[69] So, 7% is a reasonable proxy for cumulative inflation for 2024-2026. Accepting the 6.2% figure for 2024 growth in operating expenses, and with 7% as the cumulative target, implies that expense growth for 2025 and 2026 should be 0.4% each year; i.e., 6.2% followed by 0.4% and another 0.4% gives a cumulative rate of 7%.

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[67] Source: NLH-NP-011, Table 1.
[68] The 2023 growth rate is calculated based on 2022 per-customer operating expenses of $252, which is calculated by dividing $68.869 million in operating expenses by 273.8 thousand customers.
[69] For the CPI cumulative calculation: (1.025)*(1.022)*(1.02) – 1 = 0.069. Calculation of the cumulative inflation based on the forecast inflation for the GDP deflator follows the same procedure.

Based on the forecast (from Table 5) of $285 operating expense per customer in 2024, those 0.4% growth rates imply operating expenses per customer should be held to $286 for 2025, and $287 for 2026. Multiplying $286 and $287 by the respective forecast number of customers gives $79.4 million for 2025 and $79.9 million for 2026. This means reducing the proposed operating expenses, as given in the GRA's Exhibit 7, by $2.5 million in 2025 and $5 million in 2026[70].

***Recommendation. For 2025 and 2026, proposed operating expenses should be reduced by $2.5 million and $5 million, respectively.***

In addition to the preceding recommendation, two specific components of operating expenses arose in the GRA process. These are executive compensation and insurance costs. Recommendations on each follow.

### 3.3 Executive Compensation

Compensation for Newfoundland Power's four executive officers consists of four components. They are: base salaries, short-term incentives (STI), long-term incentives (LTI) and other benefits.[71] STI payments are bonuses that depend on achievement of corporate targets and individual performance. LTI payments are additional bonus payments that are tied to the price of Fortis shares and involve payouts to executives in terms of cash and/or Fortis shares, with the requirement that the executives own a specified minimum number of Fortis shares.[72] Other Benefits is the "*estimated value of the sum of the employer provided benefit, perquisite, and retirement programs*."[73]

Table 7 below summarizes these payments and shows the total and main components of compensation as well as the portions borne by customers and Fortis. Note that the figures for the STI are based on the assumption that corporate targets are achieved but actual STI payments could be higher if outcomes are beyond the targets.[74] Also, the last line of the table provides the average compensation for the four executives. This table serves as starting point for discussion of two issues: the overall level of compensation and the portion paid by customers.

***Table 7***
***Projected Executive Compensation 2024[75]***

| | Paid by Customers | Paid by Fortis | Total |
|---|---|---|---|
| Actual Salaries | $1,471,000 | $0 | $1,471,000 |
| STI (Target) | $493,812 | $95,288 | $589,100 |
| LTI | $0 | $835,900 | $835,900 |

[70] $81.9 million - $79.4 million = $2.5 million, and $84.9 million - $79.9 million = $5 million.
[71] Based on the Korn Ferry, Executive Compensation Review, page 7, the figure for other benefits "is the estimated value of the sum of the employer provided benefit, perquisite, and retirement programs."
[72] Newfoundland Power, Annual Information Form for the year ended December 31, 2023, page 17.
[73] Korn Ferry, Executive Compensation Review, April 11, 2024, page 8.
[74] According to NLH-NP-114, payouts were higher than the target 50% of salary of the president/CEO and the 35% of salary for the other three executives in both 2022 and 2023. For instance, in 2023, the president received an STI payment equal to 57.4% of salary.
[75] Based on data contained in Korn Ferry, Executive Compensation Review, April 11, 2024, Tables 2 and 3.

| | | | |
|---|---|---|---|
| Other Benefits | $0 | $482,571 | $482,571 |
| Total | $1,964,812 | $1,413,759 | $3,378,571 |
| Average | $491,203 | $353,440 | $844,643 |

As shown (last column's last line), average annual compensation of Newfoundland Power's executives is approximately $845,000. In support of these compensation levels, Newfoundland Power submitted an "Executive Compensation Review," a report prepared for it by Korn Ferry. That consultant provided a comparator group of 390 commercial industrial organizations operating across Canada, which was used to gauge Newfoundland Power's executive compensation; see Appendix C of its report. Korn Ferry reports that Newfoundland Power sets its pay standards relative to the median of executive salaries of the comparator group. With respect to the organizations in the comparator group, Korn Ferry (page 7) states:

> *The organizations are comparably classified as "private sector commercial industrial" and NFP competes for its executive resources with organizations across the breadth and depth of business sectors across Canada.*

That statement is not convincing at all.

Newfoundland Power would be an outlier in that group. It is a regulated public utility with a monopoly in a specific geographic area. No such entity is in the comparator group so while those in the group may well be "comparably classified" to one another, Newfoundland Power would not be. In fact, when asked to "identify all electrical utilities in Canada included as participants" listed in its comparator group the response gave only three "electric utilities"; (PUB-NP-173). They are EDP Renewables, Franklin Electric and Pattern Energy Group Inc. Even those three companies are quite different from traditional public utilities like Newfoundland Power. They are innovative energy companies. Brief descriptions of the three follow.

- EDP Renewables is an international business that focuses on wind and solar energy https://www.edpr.com/en/edpr/what-we-do.

- Franklin Energy describes itself as follows: "*The way we use energy is changing, and Franklin Energy is at the forefront of this monumental transition. From electric vehicles and building decarbonization to the advent of smart, grid-interactive homes, to an accelerating focus on sustainable energy affordability and equitable access, we are witnessing the most significant energy transformation in generations—for our utility clients, our state energy office clients, and more.*"
  https://www.franklinenergy.com.

- Pattern Energy Group Inc. is a renewable energy business. Its website states "*We develop, construct, own, and operate high-quality wind, solar, transmission, and energy storage projects across North America.*" https://patternenergy.com/about. Pattern does have a project in Newfoundland but it is not a public utility project. "*Argentia Renewables is a renewable energy powered green hydrogen and ammonia production and export facility. The project will*

*utilize Newfoundland & Labrador's outstanding wind resource to produce cost-competitive, green fuels readily available for export to global markets.*"
https://patternenergy.com/projects/argentia-renewables.

More generally, the types of businesses in the comparator group face very different challenges than a traditional regulated monopoly like Newfoundland Power. As such, the pressures on executives, despite similar job titles and roles, can be far more demanding. Consider a few examples from the comparator group.

- Jaguar Land Rover. In 2019 that automotive company was in difficulty and announced thousands of jobs layoffs; www.bbc.com/news/business-46822706. From 2018/19 to 2022/23, profit was negative until recovery in 2023/24:
  https://en.wikipedia.org/wiki/Jaguar_Land_Rover.

- Bell Canada. In early 2024 Bell announced large revenue losses and 1,300 layoffs; https://ca.billboard.com/fyi/massive-bell-losses-result-massive-cutbacks-media-company. The Financial Post reported that Bell would be cutting 4,800 jobs and selling 45 radio stations. https://financialpost.com/news/bce-cutting-4800-jobs-selling-45-radio-stations.

- First Quantum Minerals. In 2023, this copper producer, one of the world's largest, incurred a loss of almost $1.5 billion. According to its CEO, "*2023 closed with the Company facing one of its biggest challenges in recent history. However, I am confident in the resilience of First Quantum and the determination of our teams to work through these challenges. The Company continues to take a proactive approach to managing its balance sheet and addressing its liquidity in a fulsome and disciplined manne*r."
  https://s24.q4cdn.com/821689673/files/doc_financials/2023/q4/FQM-News-Release-2023-Q4-FINAL.pdf.

The challenges faced by these businesses simply do not happen with Newfoundland Power. Under existing legislation, the company is assured a reasonable return and there are various regulatory mechanisms that protect the utility's finances. The fact that Newfoundland Power has similarly titled executive positions that involve similar tasks does not mean that the work in terms of time, pressure, creative thinking, and stress is the same there as with commercial organizations operating in dynamic, volatile and competitive markets.

Reference to comparator group from Korn Ferry's dataset is unhelpful as an objective mechanism for setting executive compensation at Newfoundland Power. In this particular case, the "Streetlight Effect" is in play. That effect describes the tendency to look for answers in the easiest place rather than the right place. It is often expressed by the story of someone at night looking under a streetlight for his lost keys rather than looking where he most likely dropped them; when asked why, he replies "because the light is better there." Thus, looking under the streetlight (using the selected comparator group) is an impediment for finding the keys (the appropriate compensation).

PUB-NP-172 asked Korn Ferry what comparator other than the Canadian Commercial Industrial Market could be appropriate to evaluate Newfoundland Power's executive compensation. The response was:

> "*It would also be appropriate to include Canadian electrical utility sector organizations that share a similar operating and regulatory environment for evaluating Newfoundland Power's executive compensation. However, due to the different ownership structures and business models, compensation comparability could be a challenge. Ideally, private sector electrical utility organizations would be appropriate if the number of organizations is sufficient and stable. However, Korn Ferry's database does not have enough comparable utility organizations from the private sector to conduct a full analysis.*"

That answer is another example of choosing to look under the streetlight while the keys are elsewhere.

Not only does Newfoundland Power's public utility characteristic make it distinct from the comparator group but there is no evidence presented by Korn Ferry that "*NFP competes for its executive resources with organizations across the breadth and depth of business sectors across Canada.*" In the public hearings, Mr. Simmons questioned Mr. Ma, of Korn Ferry, about that statement in light of the fact that Newfoundland Power's executives "*all came up through the Newfoundland Power or Fortis organization and did not come from other business organizations in Canada.*"[76] When pressed on the question of whether the statement was a fact or assumption, Mr. Ma conceded that it was an assumption.

In fact, all Newfoundland Power's current executives are originally from Newfoundland and Labrador, are graduates of Memorial University, and have spent most of their careers at Newfoundland Power and/or Fortis companies.[77] They were not hired from any organizations in the comparator group. It seems that Newfoundland Power's general practice is, and has been, to fill executive positions by selecting individuals with many years of progressive experience in non-executive positions within the company. This succession-planning-from-within enables the company to get to know the strengths of individuals hired into technical and middle management positions. As those individuals gain many years of experience working within the regulated electric utility and become highly knowledgeable of the workings of the company, they form a talent pool from which executives can be selected. Whether, after many years with the company, their skillsets would be sought after by organizations that are not public utilities, or related to public utilities, is questionable.

With Newfoundland Power hiring executives in-house and not competing with the comparator group, what point of reference for executive compensation would be appropriate? One approach is to look at compensation paid by other electric utilities. For illustration, Table 8 gives the

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[76] Testimony of June 25, Pages 101-102.
[77] See https://www.newfoundlandpower.com/About/Who-We-Are/Our-Leaders.

compensation of the Presidents/CEOs at three eastern Canadian electric utilities and at Newfoundland Power[78].

***Table 8***
***President/CEO Compensation***

| | |
|---|---|
| NL Hydro (2023) | $399,800 |
| New Brunswick Energy (2023) | $374,999[79] |
| Hydro-Quebec (2023) | $751,215 |
| Newfoundland Power (2024) | $1,359,451 |

The CEO of Newfoundland Power is much more highly paid than the CEOs of the three other utilities. Yet, those other utilities are larger and more complex organizations. Compensation for Newfoundland Power's chief executive is clearly out of line with the others.

Newfoundland Power, New Brunswick Energy, NL Hydro and Hydro-Quebec are similar in many ways. Their core business involves some combination of generation, transmission and distribution of electricity and they are all subject to utility regulation in accordance with legislation in their respective provinces. One difference is that the three other electric utilities are owned by provincial governments whereas Newfoundland Power, like organizations in the comparator group, is not. However, it is difficult to accept that this one difference more than offsets all Newfoundland Power's commonalities with provincial government owned regulated electric utilities operating in this province and nearby provinces.

Newfoundland Power's executive compensation cannot be credibly defended by reference to the selected comparator group. The compensation is excessive and consumers should not be compelled to pay for the excess. Customer rates should include reasonable compensation only. That is what happens in Nova Scotia.

Nova Scotia Power Inc. (NSPI) is a privately owned regulated electric utility and with a single shareholder, Emera. Under Nova Scotia's Public Utilities Act:

- "*Nova Scotia Power Incorporated shall not recover from any rate, charge or fee approved by the Board (a) any bonus or incentive compensation; or (b) any other remuneration, except remuneration that is prescribed by the regulations, paid to an executive employee of Nova Scotia Power Incorporated as identified in an approved report or determined by the Board.*"[80]

and

[78] Respectively, www.gov.nl.ca/exec/tbs/files/Newfoundland-and-Labrador-Hydro-and-Affiliates-Compensation-Disclosure.pdf; gnb.socrata.com/Public-Accounts/2023-Employee-Salaries-Traitements-des-employ-s/8m35-292e/data_preview; www.hydroquebec.com/data/documents-donnees/pdf/annual-report-2023-hydro-quebec.pdf; and Korn Ferry, Executive Compensation Review, April 11, 2024.
[79] Payment may be less. Only a pay scale is reported; it is $350,000 to $374,999.
[80] Nova Scotia Public Utilities Act, Section 64B(8).

- *"The Governor in Council may make regulations (a) prescribing the remuneration of an executive employee of Nova Scotia Power Incorporated that Nova Scotia Power Incorporated may recover from a rate, charge or fee approved by the Board, which remuneration must be derived from the pay plan, as established from time to time, used for deputy ministers in the public service of the Province."*[81]

These provisions mean that NSPI consumers pay for NSPI executive salaries only, and those salaries are set in line with those paid to provincial government deputy ministers. However, total compensation of NSPI executives are much higher than their salaries because its parent, Emera, provides additional benefits based on various incentive mechanisms, which are tied to the price of Emera shares. For example, the President/CEO of NPSI received a salary of $323,205 in 2023, which was paid by customer rates, but that person was paid additional benefits of $1.4 million through incentives paid for by Emera.[82] Thus, NSPI consumers paid about 19% (= $323,205/$1,730,000) of the total remuneration for the CEO in that year.

Referring back to Table 7, the total compensation for Newfoundland Power executives is $3,378,571 and customers paid $1,964,812 of it. Thus, the majority, approximately 58% (i.e., $1,964,812/$3,378,571), comes from customer rates. As also shown in the table, consumers do not pay for the LTI and Other Benefits but pay all of the base salaries of $1,471,000, which are not capped like in Nova Scotia.

However, customer rates pay for most of the STI; $493,812 out of $589,100, which is approximately 84%. The magnitude of the STI payments depends on performance evaluations, which are assessed according to the extent to which corporate and individual performance targets are achieved.[83] Under the Nova Scotia arrangements none of the STI bonuses would be supported by customer rates. The shareholder pays them. This makes sense because the shareholder is the beneficiary.

PUB-NP-147 asked "*explain what benefits do customers experience from the operation of Newfoundland Power's short-term incentive plan and explain why customers should bear any costs of the short-term incentive plan, particularly now given the significant increase in operating costs from 2023TY to 2026 forecast TY.*" The core component of the response is:

- *"Corporate performance targets for reliability, customer satisfaction and controllable operating costs per customer have direct customer benefits. Achieving reliability targets relates to the effectiveness of the Company's response to outage events, with a focus on maintaining overall reliability for customers. Achieving customer satisfaction targets is a direct measure of the level of satisfaction customers have in the service Newfoundland Power provides. Management of controllable operating costs also directly benefits customers.*

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[81] Nova Scotia Public Utilities Act, Section 118(1)(a).
[82] https://www.halifaxexaminer.ca/economy/energy/nova-scotia-power-president-peter-greg-gets-a-65-raise-now-makes-1-73-million/
[83] Under P.U. 19(2003), STI payouts in excess of 100% of target are not regulated expenses.

*Safety performance targets include all injury frequency rate and quality leading indicators. These aim to protect the health and safety of the Company's employees, indirectly contributing to the reliable provision of service to customers.*

*Finally, financial and regulatory performance targets also benefit customers. Sound financial and regulatory performance, including earning the Company's allowed return, maintains Newfoundland Power's financial integrity and contributes to a sound credit rating. This translates into lower costs for customers and is consistent with the Company's least-cost delivery of service to customers.*"

That response is unconvincing. The incentive scheme is not designed to target customer benefits. Further, the incentive scheme is set by the board of directors of Newfoundland Power; customers have no role in its design. Targets for reliability, customer satisfaction and controllable operating costs are well and good but reliability and customer satisfaction are part of the responsibility of the utility, not things that require a bonus. Targets for controllable operating costs sounds appealing but that ignores other costs. For example, there are no targets for depreciation costs per customer yet, with a time lag, such costs are controllable. They can be reduced or their growth reduced by adjusting capital expenditures, the growth of which the Consumer Advocate has repeatedly criticized. Similarly, there is no consideration in the targets for finance costs per customer. Growth in that cost is largely driven by capital spending, which Newfoundland Power determines. By including operating costs but not the others, the scheme creates an incentive for more capital expenditure, and the resulting higher depreciation and finance costs may offset any improvements in operating costs. A bias to capital spending is not in the customer's interest.

As for reliability, that is a fundamental outcome that Newfoundland Power is required to provide at a reasonable level, not something that warrants a bonus. In this regard, the Consumer Advocate has repeatedly expressed concern that Newfoundland Power's targeting of reliability levels much higher than that of other utilities has been costly to customers. The customer satisfaction surveys, which Newfoundland Power commissions, does not ask customers about the trade-off between increased reliability and increased cost, nor do they investigate customers' willingness to pay for the substantially above-the-norm reliability statistics.

Safety of employees and the general public for that matter is, of course, desirable but it is more than that. Safety is a responsibility. All businesses are required to meet occupational health and safety standards and other safety laws and regulations. Moreover, Newfoundland Power management and its unionized employees can work together to ensure workplace safety. Yes, there are indirect benefits to customers but they should happen anyway, and not require a bonus payment to executives.

No one disputes that it is desirable for Newfoundland Power to have financial integrity and a sound credit rating. That is provided for in legislation and the regulatory process is supportive of that objective. It is made possible by the rates that customers pay. Does maintaining a sound financial position really require a bonus payment, largely financed by the customers, to executives every year?[84] Surely, the executives' base annual salaries, which in 2024 average approximately $368 thousand, are for something.[85]

Customers have no part in the design of the STI plan and should not be required to pay for any of it. The STI plan is designed to incentivize the executives to do what is best for Newfoundland Power's shareholder, not its customers. Newfoundland Power admits exactly that in its Annual Information Form:[86]

> "*A significant portion of total annual executive compensation is at risk due to the use of short-term and long-term incentive components. For 2023, approximately 60% of the President & Chief Executive Officer's total annual compensation was designed to be at risk. Approximately 45% of other executive officers' total annual compensation was designed to be at risk. Total annual compensation includes both the cash compensation paid to the executive officers in the year and the estimated compensation for the long-term incentive components.*
>
> *This approach is intended to best serve the interests of shareholders by ensuring that executive officers are compensated in a manner that advances both the short-term and long-term interests of shareholders.*"

The last sentence of the quote is very clear. It's about the shareholder interest. The consumer is not mentioned.

While having an incentive plan for executives is reasonable for the utility, it is not reasonable or fair that customers pay for it when its stated purpose is to serve the interests of the shareholder.

***Recommendation: Beginning January 1, 2025, all future payments associated with Newfoundland Power's short-term incentive plan for executives should be paid by the shareholder.***

That leaves the question of executives' base salaries. In Nova Scotia, they are determined according to legislation. That is not the case in this province but they could be set by the regulatory process. That could be an overreach for the Board because doing so would limit management's scope to decide what it considers as the appropriate compensation for its executives.

However, given the very generous overall compensation received by the executives, it would be fairer to consumers if they did not have to support the entire cost of executives' base salaries. Some contribution from the shareholder would be fair. That would not interfere with Newfoundland Power's freedom to set remuneration levels and, at the same time, would relieve the consumer of

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[84] In testimony the President of Newfoundland Power indicated that he was not aware of any executive not receiving incentive payments in any years since he joined the executive in 2014; Testimony of June 13, 2024, page 122.
[85] Based on data in Korn Ferry, Executive Compensation Review, Table 2. Salaries of the four executives are given as $495,000, $345,000, $345,000 and $286,000.
[86] Newfoundland Power Inc., Annual Information Form, for the year ended December 31, 2023, page 13.

some more of the very high cost of the utility's executive compensation. A reasonable portion is 20%.[87]

***Recommendation: Beginning January 1, 2025, 20% of Newfoundland Power's executives' base salaries should be paid by the shareholder.***

The estimated cost savings to customers due to this recommendation and the one relating to the STI are given in Table 9.

***Table 9***
***Cost Saving to Customers from Proposed Contribution from Shareholder***

| | 2025 | 2026 |
|---|---|---|
| 100% of Executive STI[88] | $519,000 | $542,000 |
| 20% of Executive base salary[89] | $298,400 | $311,800 |
| Total | $717,400 | $853,800 |

These payments should be designated as non-regulated costs and accordingly should be removed from proposed 2025 and 2026 operating expenses.

### 3.4 Insurance Cost

Exhibit 2 from the GRA shows insurance costs in 2022 at $2.2 million increasing to $2.9 million in the 2026 test year. For example, in the June 17, 2024 Transcript, pages 6 to 10, Mr. Fitzgerald cross-examined Ms. London about how Newfoundland Power procures insurance. Ms. London explained (pages 6 to 9) that insurance is an expense of Newfoundland Power, but Fortis does the negotiating for the insurance program on behalf of Newfoundland Power. Ms. London further explains (pages 8 and 9) that Fortis negotiates insurance on behalf of all Fortis subsidiaries including Newfoundland Power. Mr. Fitzgerald asked Ms. London (page 10) "*So I take it then the answer is that there is no intention for Newfoundland Power to exert its own control over the insurance, it's satisfied currently to be under the Fortis umbrella of insurance coverage, if I could put it that way*?" Ms. London responded "*Yes, we are satisfied with our current coverage.*"

Although Newfoundland Power suggests that the utility and its customers benefit from having Fortis negotiating insurance on its behalf, it is not at all clear that this is the case. It appears that Fortis, rather than Newfoundland Power's customers, benefit. In a rate proceeding relating to Maritime Electric, a blanket order denies Maritime Electric recovery of all Fortis-related costs.[90] Order UE09-02 states:

[87] NL Hydro's president's base salary (2023) was $397,400 while Newfoundland Power's president's salary (2024) is $495,000. If the shareholder paid 20% of latter's base salary, then the cost of Newfoundland Power's president's salary to customers would be approximately the same as the salary of the Hydro president.
[88] Source: PUB-NP-029, Table 4.
[89] The response to PUB-NP-031, Table 1, provides the average base salary for executives as $372,962 and $389,745 for 2025 and 2026, respectively. Multiplying each by 4, the number of executives, gives the total for each year, which is then multiplied by 20% to obtain the recommended shareholder contribution.
[90] Order UE09-02 (https://irac.pe.ca/Orders/Electric/2009/UE09-02.htm)

> *[50] The Commission reviewed the schedule of these costs, which are general and administrative, such as insurance, directors' fees, audit and professional fees, etc. Based on the evidence before us, the Commission considers these costs to be more in the nature of the cost of running Fortis Inc. The Commission believes that the approved return on average common equity provides fair and reasonable return to Fortis Inc. to cover the payment of these expenditures. Therefore, the Commission will deny inclusion of these expenditures (approximately $300,000) in the revenue requirement for Maritime Electric.*

That order is reasonable and should be applied in regard to Newfoundland Power's forecast insurance cost of $2.773 million for 2025 and $2.932 million for 2026. Insurance cost should not be included in the revenue requirement until the Board is satisfied that meaningful efforts have been made to obtain the required insurance at lowest cost and until such time that Newfoundland Power shows that insurance costs are not a cost of running Fortis Inc.

***Recommendation: The $2.773 million cost of insurance proposed for inclusion in Newfoundland Power's revenue requirement for 2025 and $2.935 million in 2026 should be disallowed.***

4. ISSUES RELATING TO RECOVERY OF REVENUE REQUIREMENT

4.1 Wholesale Rate

On page 19 of Newfoundland Power's Rebuttal Evidence it is stated "*Mr. Bowman's recommendation for Newfoundland Power and Hydro to re-design the wholesale rate as part of the Company's ongoing 2025/2026 GRA is not practical or achievable.*" However, the parties signed a Settlement Agreement on June 12, 2024 stating that the wholesale rate would indeed be re-designed and submitted to the Board for approval with implementation on January 1, 2025. Rates in the 2025-2026 GRA would be re-based accordingly.

The Consumer Advocate continues to support the modified wholesale rate on the basis that it reflects marginal costs, so sends a more efficient price signal and is consistent with the least cost provision of service. It is also consistent with government net-zero emissions efforts. However, we wish to clarify the following:

1. The wholesale rate applies only to Newfoundland Power. Newfoundland Power indicates that the re-designed wholesale rate will reduce volatility in rates. As noted by Mr. Bowman in his direct evidence (June 28, 2024 Transcript, pages 13 to 52), this may well be the case next year, but not necessarily in subsequent years. Under proposed rates for Newfoundland Power's largest customer class, the Domestic class will pay an energy charge of about 14 cents/kWh. The current tail-block charge in the wholesale rate is about 18 cents/kWh. This is a difference of 4 cents/kWh. More specifically, when Newfoundland Power sells 1 kWh more than forecast, it costs them 18 cents/kWh to purchase the power from NL Hydro, but this is offset in part by a 14 cents/kWh gain in revenues.

   Under the revised rate, an additional kWh in sales above forecast will cost Newfoundland Power about 6.8 cents/kWh (averaged over the year), but its revenues will increase by 14 cents/kWh. This is difference of about 7 cents/kWh, but in this case, rather than losing about 4 cents/kWh on each kWh sold above forecast, Newfoundland Power will gain about 7 cents/kWh on each kWh sold above forecast. More specifically, under the re-designed wholesale rate, Newfoundland Power over-collects revenue, so instead of increasing rates on July 1 to recover its losses, Newfoundland Power would reduce rates on July 1 to refund the over-collected amount of revenue.

If rate volatility is to be reduced, tail-block energy charges in retail rates must likewise reflect marginal costs. Therefore, the tail-block energy charges for Newfoundland Power's retail rates should likewise be changed to better reflect marginal energy costs, not only to reduce rate volatility, but also to: 1) promote more efficient energy consumption decisions by retail customers, 2) ensure consistency with government environmental initiatives, and 3) to ensure delivery of power in a least cost manner.

2. By approving the wholesale rate framework and allowing flow-through of the cost difference late in 2024, it is possible that the Board will have two pending rate adjustments – one for the flow-through application and one for this GRA, assuming an order has not yet been issued on the GRA. While somewhat unusual, it is important to note that there are currently two outstanding requests for rate increases before the Board, including the 2024 Rate of Return on Rate Base Application and this GRA. So, while it is unusual to have two pending rate adjustments, it is not extraordinary.

***Recommendation: A new wholesale rate consistent with the Settlement Agreement dated June 12, 2024 should be implemented by January 1, 2025. Rates should be re-based according to the new wholesale rate as part of this GRA.***

4.2 Load Research Study

Three winters have passed since the settlement agreement on the 2022-2023 GRA was signed committing Newfoundland Power to undertake a load research study, but there has not yet been a single data point collected. Regardless of supply chain issues associated with meter procurement, this study should have been well underway by now. Delays of this type in the Load Research Study are inexcusable given that it is expected to take three winter seasons to accumulate the necessary data.

According to Undertaking U-08, Newfoundland Power ordered the load research meters on September 14, 2023, 8.5 months after Newfoundland Power filed its Load Research and Rate Design Framework with the Board (December 30, 2022). According to Undertaking U-11, Newfoundland Power has still not received the meters, anticipating that delivery will commence in September of this year. It is not clear that Newfoundland Power has given this program the priority it deserves. This delay is at least in part the fault of Newfoundland Power. Such delays make it far less likely that the parties will come to negotiated settlements in the future.

Yet, supply chain issues do not appear to have hindered Newfoundland Power's "New Meters" and "Replacement Meters" programs in its recent capital budgets. Further, if Newfoundland Power had smart meters installed at customer sites, there would be no supply chain issues associated with the load research study because smart meters are capable of providing the load research data necessary to undertake the study.

***Recommendation: The Board should direct Newfoundland Power to give high priority to the load research study that was agreed to by the parties at the 2022-2023 GRA.***

4.3 Connection Assets

Adjustments are needed to Newfoundland Power's Capital in Aid of Construction (CIAC) policy, its Schedule of Rates, Rules and Regulations and its cost of service study relating to the treatment of customer connection facilities, and more specifically, the connections for Memorial University via the LPD and MUN Substations, and the two mines served by the RFD and LCV Substations. This issue was raised at the MUN-T2 Transformer Replacement Supplemental Capital Budget Application and the 2024 Capital Budget Application, specifically the MUN Substation Refurbishment and Modernization project.

As pointed out in Mr. Bowman's direct evidence (June 28, 2024 Transcript, pages 13 to 52), there is a significant disparity between the cost to supply a customer from the 66kV transmission system and the cost to supply a customer from the lower voltage-rated distribution system. According to CA-NP-255, Attachment A, the BIG Substation is rated at 12.5kV and supplies 1,334 customers via the BIG-T1 transformer. It is understood that one of the 1,334 customers supplied from the BIG Substation is a Rate 2.4 customer. In CA-NP-167c it is stated "*Comparing capital costs associated with the Memorial ("MUN") Substation with Big Pond ("BIG") Substation on a per customer basis is illogical and impractical.*" In fact, it is neither illogical nor impractical. In a cost of service study, the costs of each asset are assigned to the customers that benefit from the asset. This is consistent with the fairness principle. In the case of the BIG Substation, its costs should be assigned to the 1334 customers served by the substation. Similarly, the costs of the LPD and MUN Substations should be assigned to the one customer served by the substations, Memorial University.

The Long Pond Substation was recently built by Newfoundland Power at a cost of $4.6 million, so for the sake of argument, assume the cost of the BIG Substation to be allocated to the 1334 customers served by the substation is $4 million. Therefore, the cost of the BIG Substation assigned to each customer served by the substation would average about $3000. Depending on the size of their load, some customers would be assigned more and some customers less, but the average cost assignment would be $3000/customer.

Consider Memorial University which is served by two substations, LPD and MUN. Again, for the sake of argument, assume that the cost of the LPD Substation is $4 million and the MUN Substation is $5 million (because the MUN Substation has two transformers rather than one). Therefore, in the cost of service study $9 million should be allocated to the one customer served by the Substation, Memorial University, for an average cost of $9 million/customer.

Clearly, it costs far less on a per customer basis to connect a customer to a distribution substation which serves somewhere between 621 and 10,791 customers (CA-NP-255, Attachment A) than it does to connect a single customer to the transmission system (3 orders of magnitude less). This is why it is common practice in the industry to charge the cost of facilities that benefit only one customer directly to the benefitting customer. ***It is not unusual*** to socialize connection costs among the customers within a customer class when connection costs are of the same order of magnitude (i.e., $3000/customer), because cross-subsidization is relatively minor. ***It is unusual*** to socialize the cost of a connection that benefits only one customer because it entails socializing millions rather than thousands of dollars to customers who receive no benefit from the facilities. Socializing the cost of the MUN and LPD Substations that benefit only Memorial University is contrary to the legislative requirement in the province that rates be fair and non-discriminatory. Under the current regime, the other customers in the Rate 2.4 class are paying a huge subsidy to Memorial University because the connection cost for the University is 3 orders of magnitude greater than the typical connection cost of other Rate 2.4 customers.

As noted in Mr. Bowman's direct evidence (June 28, 2024 Transcript, pages 13 to 52), in the past 3 or 4 years, Newfoundland Power has spent $4.6 million developing the LPD Substation, $3.3 million upgrading/expanding the LPD Substation, $1.6 million on the MUN-T2 transformer replacement and $4.4 million on the MUN Substation refurbishment and modernization project. This is a total of $13.9 million spent on connection assets that benefit only one customer, Memorial University, and equates to $13,900,000 per customer. If Newfoundland Power had spent $13,900,000 on the BIG Substation, the cost would equate to $10,400/customer. This is a cost difference of $13,889,000/customer, or 133,554%. Clearly, socializing the costs of the University's connection assets across the customers in the Rate 2.4 customer class is exceedingly unfair.

Put another way, in the 2024 Capital Budget Application, Newfoundland Power proposed four substation refurbishment and modernization projects, including:

- MUN Substation serving one customer, Memorial University, at a cost of $4.4 million
- GAM Substation serving 4870 customers at a cost of $5.3 million
- OPL Substation serving 1770 customers at a cost of $3.4 million
- ISL Substation serving 2820 customers at a cost of $5.0 million

Therefore, the GAM, OPL and ISL Substations are being refurbished at a total cost of about $13.7 million. This equates to about $1,450/customer ($13.7 million/9460 customers). This compares to $4,400,000/customer in the case of the MUN Substation refurbishment. This is a cost difference of $4,398,550/customer, or 303,348%. Again, socializing the costs of the University's connection assets across the customers in the Rate 2.4 customer class is exceedingly unfair.

Finally, as noted in Mr. Bowman's direct evidence (June 28, 2024 Transcript, pages 13 to 52), a properly designed transmission tariff ensures open and equal access to the transmission system in a competitive electricity market. When developing a transmission tariff, it is first necessary to define the assets that make up the transmission system (e.g., all transport facilities rated 66kV and above). Once the transmission assets have been defined, it is necessary to identify which assets are network facilities, referred to as common facilities in this jurisdiction, and which assets are radial facilities, referred to as connection facilities, or specifically-assigned assets in this jurisdiction. Only network facilities are included in the transmission tariff because these facilities benefit all, or most, customers. Connection facilities benefit only one, or a few, customers, so the costs of these assets are allocated directly to the customers that benefit and are excluded from the calculation of the transmission tariff.

According to CA-NP-301, the MUN Substation was originally constructed in 1966 to supply the University. Portions of Transmission Line 12L, which now connects the Kings Bridge Substation to the MUN Substation, and 14L, which now connects the Stamps Lane Substation to the MUN Substation, were constructed prior to 1966, and were connected to MUN Substation at the time of its construction.

In 1966 (and perhaps earlier), the University would have requested to be connected to Newfoundland Power's system. Owing to the very large size of the load, Newfoundland Power would have been required to build the brand new MUN Substation – it was impractical to simply run a line to an existing substation because the load was too great. Lines 12L and 14L existed at the time, and were in the vicinity of the new substation, so were extended and terminated at the MUN Substation to supply the substation and the University. It is likely that lines 12L and 14L required upgrading to carry the additional load of the University.

Therefore, the MUN Substation was built for the sole purpose of supplying Memorial University. This is referred to in the industry as a "shallow connection" – the minimum facilities necessary to connect the customer to the system. However, Newfoundland Power also had to upgrade and terminate each of lines 12L and 14L at the substation in order to supply the University. The requirement to upgrade and terminate these lines is referred to in the industry as "deep connection" facilities. There is little debate in the industry that shallow connection facilities should be paid by the benefitting customer. Newfoundland Power has provided no evidence of any other jurisdiction that does not charge the cost of shallow connection facilities directly to the benefitting customer. Even in this jurisdiction, NL Hydro charges shallow connection costs directly to the benefitting customer via a specifically-assigned charge.

However, as Mr. Bowman indicated in his direct evidence (June 28, 2024 Transcript, pages 13 to 52), there is intense debate in the industry about whether a customer should be required to pay deep connection costs. In the case of 12L and 14L, the lines were necessary to connect the University. But they also provide benefits to other customers as they close the loop around the city of St. John's enabling back-feeding when a line out of either Stamps Lane or Kings Bridge Substations is forced out of service. NL Hydro is dealing with the issue of deep connection facilities in Labrador with the data centers. There is little debate that these customers should pay the costs to connect to the system, but intense debate over who pays when the connections require upgrades to the grid at significant cost.

In the case of the University, Mr. Bowman recommends in his direct evidence (June 28, 2024 Transcript, pages 13 to 52) that the University pay all costs associated with the MUN and Long Pond Substations, but not the costs of lines 12L and 14L because these lines were built during a time when load growth was presumably much higher than it is today, meaning it is possible that Newfoundland Power would have connected and upgraded the capacity of these lines in the absence of the University. This argument does not hold for the MUN and LPD Substations because these substations benefit only the University and no other customer on the system.

Further relating to the connection issue, consider that the RFD and LCV Substations each serve a single Rate 2.4 customer. It is understood that these are mining customers. In each case the mines served by the RFD and LCV Substations have already paid in full for their connections. By assigning all costs of connections that serve Rate 2.4 customers to the Rate 2.4 class, the two mines are paying a share of the connection costs of all other customers in the Rate 2.4 customer class, including the very high cost of the connection of Memorial University, even though the mines have already paid for their own connections. This is blatantly unfair to the mines, but making matters worse, Newfoundland Power is also allocating costs of distribution facilities to the mines, and for that matter, Memorial University, even though distribution facilities are not used in their supply.

As discussed in Mr. Bowman's Pre-filed Evidence, CA-NP-272d states "*Distribution facilities are not used to supply the customers served by the RFD and LCV Substations since those customers are served at 66 kV transmission voltage. Memorial University is served by distribution facilities owned by Newfoundland Power at the Memorial ("MUN") Substati*on." However, as shown in CA-NP-255 Attachment A, Memorial University is served from the 66kV MUN and Long Pond Substations. Just because Newfoundland Power chooses to own the substations and meter at the low-voltage side of the transformers does not mean that the University is supplied by the distribution system. Second, as stated in CA-NP-272c "*Approximately $3.8 million of Newfoundland Power's annual distribution costs are allocated to the General Service Rate #2.4 customer rate class.*" Therefore, the Rate 2.4 customers served from the RFD and LCV Substations, and Memorial University are paying for distribution facilities that are not used in their supply.

It is for this reason that customer classes are often differentiated by voltage supply level to ensure customers pay only for those facilities used in their supply. For example, "*Manitoba Hydro has three distinct prices for customers who are classified as large. All three are flat rates and the energy price is differentiated by customer kV service level.*"[91] Because Newfoundland Power does not have a separate class for customers supplied at the 66kV transmission voltage, the two mines and the University are paying a rate that is higher than it should be. Rates to these customers should not include the cost of connection facilities and distribution facilities. By recovering such costs in rates for these customers Newfoundland Power is violating legislation requiring that rates be fair and non-discriminatory. As recommended by Mr. Bowman in his Pre-filed Evidence (Recommendation # 11), the only logical way to resolve this issue is to hive off these three customers from the Rate 2.4 class and put them in a class of their own with their own rate that excludes the costs of connection and distribution facilities.

In summary, Newfoundland Power's policies and cost of service study require revision to ensure that customers connected to the 66kV transmission system are responsible for the cost of their connections. The connection costs and recovery should be between the party requesting the connection and Newfoundland Power, and the costs should ***not*** be included in rate base. This change has to be addressed in this GRA. The problem exists now, and there are no studies underway or proposed that will change this fact. Delaying action would likely carry the discrepancy forward by another 3 years until the next GRA, and possibly longer if Newfoundland Power chooses to continue to ignore the issue as it has in this GRA. There is always new information coming in – the world is in a state of constant transition. Waiting on new information is a poor excuse for doing nothing.

[91] CA Energy Consulting report dated April 1, 2024 entitled Rate Design Review: Phase 1 (page 61).

A final word on this issue. Changing Newfoundland Power's policies and cost of service does not fully address the problem. The Board also needs to issue an Order clarifying how connections will be addressed in the future. Every Order issued by the Board sets regulatory precedent. While changing Newfoundland Power's policies addresses the issue for Newfoundland Power, it does not address the precedent set by the Board respecting connections to NL Hydro's customers. The previous Board Orders must be clarified so all parties regulated by the Board are playing by the same set of rules.

***Recommendation: The Board should direct Newfoundland Power to work with the Consumer Advocate to*:**

***a. Form a new General Service customer class (e.g., Rate 2.5) including customers served directly from the transmission system. This would include the two mines served from the RFD and LCV Substations, and Memorial University. The new class would be responsible for payment of their own connection costs and would not be responsible for paying distribution costs that are not used in their supply.***

***b. Make adjustments to the cost of service for General Service Rate 2.4 customers to account for the transfer of demand and costs to the new Rate 2.5 customer class.***

***c. Re-draft Newfoundland Power policies (Rates, Rules and Regulations and CIAC policy for General Service customers) to account for the new General Service customer class, and clarify that customers served directly from the transmission system will be directly responsible for payment of the costs of their connections.***

***This issue should be addressed now so it can be included as part of the Board's Order on this GRA.***

4.4 Street and Area Lighting

Street and Area Lighting customers have benefitted from the LED Street Lighting Replacement Program through a significant reduction in electricity costs. No other customer class has received benefits that come close to the magnitude of savings realized by Street and Area Lighting customers. While it is acceptable to have benefit to cost ratios stemming from the cost of service study that are within a range of 90% to 110%, there is no reason why a customer class that has received a significant cost reduction that other customers have not received, should not pay 100% of the cost of supply. A benefit to cost ratio that is less than 100% implies that a subsidy is being allotted to a customer class that is already realizing a significant cost reduction that other classes are not receiving.

***Recommendation: Rates for Street and Area Lighting class should be increased to 100% of the cost of supply. Use the resulting increase in revenues to reduce the proposed rate increase for other customer classes that are paying close to 110% of the cost of supply.***

## 4.5 Current Retail Rates

Mr. Bowman recommends (Pre-filed Evidence, Recommendation #7) that the Board order Newfoundland Power to cooperate with Hydro and the Consumer Advocate to modify retail rates to better reflect the marginal cost of energy in tail-block energy charges. This does not necessarily translate to changes in rate designs, but rather changes to the charges in the components of existing rates to bring them more in line with marginal costs. This is a similar proposal to that agreed to by the parties with respect to the wholesale rate.

It is important to reflect trends in marginal costs, and Newfoundland Power should take advantage of the opportunity to reflect such trends in this GRA. In Newfoundland Power's Rebuttal Evidence (page 20) it is stated "*Completing a comprehensive review is necessary to ensure any new rate designs appropriately meet established regulatory principles, are acceptable to customers, and do not result in unintended consequences.*" However, it is not necessary to undertake a comprehensive review when changes are only being made to the charges within existing rate designs. Newfoundland Power did not undertake a comprehensive review that led to its proposal to increase each component of each retail rate by the proposed 5.5% rate increase, to the extent possible. The only concern is that you must be mindful of making changes that cause excessive rate impacts on customers. That is why it is important to make changes gradually to minimize rate impacts over time. Rate design is a balancing act. There is no perfect rate. On the other hand, rate designs can always be improved. When opportunities arise such as that presented in this GRA, it is best to take advantage.

Newfoundland Power suggests that it is concerned about changes to rate designs owing to potentially adverse customer rate impacts. While adverse customer rate impacts are clearly a concern of consumers, it is not so clear that it is a concern of Newfoundland Power given that it is proposing a 7% rate increase in the 2024 Rate of Return on Rate Base Application and this GRA. Further, as noted earlier, rates are expected to increase 23% over the year beginning July 1, 2024 and ending July 1, 2025. When asked by NL Hydro if Newfoundland Power considered smoothing rate impacts for customers (NLH-NP-001 pertaining to July 1, 2024 Customer Rate Application), Newfoundland Power responded that it "*has been actively working towards potential solutions to smooth customer rates. These efforts are focused on smoothing customer rates between 2025 and 2026.*" More specifically, in the opinion of Newfoundland Power, customers are stuck with the proposed 9.3% rate increase effective July 1, 2024. Newfoundland Power's "concern" about rate volatility only goes so far, and ends when its revenues are threatened.

It is very difficult to design rates through testimony as there is a need to check different rate combinations versus customer rate impacts. As noted, rate design is a balancing act. For this reason, the Consumer Advocate has in the past worked with Newfoundland Power rate design specialists to design rates. Mr. Bowman has in fact worked with rate design specialists at both Newfoundland Power and Nova Scotia Power to develop rates that turned out to be much better than had either party developed the rates on its own.

Reflecting marginal costs in rates is accepted practice in Canada and the United States. CA Energy Consulting, Newfoundland Power's current rate design consultant, makes a number of comments in this regard in its April 1, 2024 report. On page 55 they state that Newfoundland Power seems well positioned with its current rate designs for the General Service classes that are structured to provide marginal cost-based price signals. In fact, CA Energy Consulting recommends that Newfoundland Power leave current rate designs in place and adjust customer, demand and energy charges to collect the revenue requirement and more adequately reflect changes in Hydro's marginal costs. It is important to note that CA Energy Consulting is not only recommending that existing rate designs be modified to reflect marginal costs, but also recommends that rates be modified to reflect Hydro's marginal costs, meaning that it is not necessary to first modify the wholesale rate before making changes to the charges in existing retail rate designs. CA Energy Consulting states (page 55) that Newfoundland Power might also consider adjustments to the General Service demand charges to send customers "*stronger and more cost-based price signals about winter marginal capacity costs*". CA Energy Consulting's recommendations are entirely consistent with those of Mr. Bowman.

Before leaving the CA Energy Consulting's report, in Appendix A it is stated "*Efficient prices provide market signals about the present and future cost of providing energy service, which encourages customers to use electricity economically and utilities to build the minimum system necessary to meet the demands of customers. This is known as allocative efficiency.*" In other words, reflecting marginal costs in rates is least cost, a term used extensively by Newfoundland Power in this GRA and its Capital Budget Applications. Ironically, adjusting the components of existing retail rate designs to better reflect marginal cost is likely the lowest cost program available to Newfoundland Power that is consistent with the provision of least cost power. Perhaps the fact that such rate adjustments would not add to rate base is what is holding Newfoundland Power back from pursuing this least cost program.

***Recommendation: The Board should direct Newfoundland Power rate specialists to work with the Consumer Advocate to alter the charges in current rate structures to better reflect marginal costs. The revised rates should be included in the Board's decision on this GRA.***

### 4.6 Optional Rates

Mr. Bowman recommends that existing rate options be updated to reflect marginal costs. Again, Mr. Bowman is not recommending changes to existing rate designs at this time, but rather changes to charges in existing rate designs to better reflect marginal costs. A rate design consultant is not needed to tell you that marginal costs are no longer 18 cents/kWh so changes should be made to reflect updated marginal costs.

***Recommendation: The Board should direct Newfoundland Power rate specialists to work with the Consumer Advocate to alter the charges in current optional rates to better reflect marginal costs. The revised optional rates should be included in the Board's decision on this GRA.***

## 5. OTHER ISSUES

### 5.1 Advanced Metering Infrastructure

Mr. Bowman recommends that Newfoundland Power conduct a study on the costs and benefits of Advanced Metering Infrastructure (AMI, or smart meters) by year-end 2024. The conduct of such a study is straightforward as there are numerous templates around upon which to base the study. In the June 26, 2024 transcript (page 135-136) Mr. Chubbs states with respect to smart meters "*So we've studied it a number of times, right, to see whether it's least cost or not and what came out of* *the Dunsky study was that it could become least cost within the next decade, right, and with a big shift in technology like that and a five-year implementation, so we're talking now it could be five years from implementing, right, so we're continually looking and evaluating*." However, there is no study on the record that assesses ***all*** benefits of smart meters. Mr. Comerford, the Director, Rates and Supply and a direct report to Mr. Chubbs, was asked by Mr. Fitzgerald with respect to a smart meter study undertaken by Newfoundland Power (June 27, 2024 Transcript, page 118) "*So is there a hard document at Newfoundland Power that actually concludes after a review of smart meters that it does not meet least cost criteria at this point*?" Mr. Comerford responded "*Not that I'm aware of, but as I indicated, that's not really in my area of responsibility.*" How could the Director, Rates and Supply be unaware of such a study that is tied directly to retail rates and the ongoing rate design study unless such study does not exist? In CA-NP-034 Newfoundland Power states that it is "*preparing to model the costs and benefits associated with implementing AMI technology.*" This means that they have not undertaken such a study. Given that smart meters require a 5-year implementation plan, and that 94% of Canadian households and businesses are forecast to have smart meters in the next two years, what is Newfoundland Power waiting for?

In the June 26, 2024 transcript (pages 136-137) Mr. Chubbs states with respect to smart meters "*And we're also looking at, you know, the other potential benefits here, they are small, but when I look at Nova Scotia and New Brunswick, you know, they layered on a lot of benefits to kind of get to the, to reach that, I think for New Brunswick Power it was 123 million dollar, 120 million dollar investment, but they had a lot of benefits layered in there, right, smaller ones*." This is precisely what is needed – a study that assesses all benefits of smart meters to Newfoundland Power's customers, not only the benefits relating to load shifting. It is forecast that two years from now, 94% of Canadian households and businesses will have smart meters (PUB-CA-026i). The Board needs to know why so many other jurisdictions are embarking on smart meter programs when Newfoundland Power has not undertaken a study backing its claim that smart meters are not currently least cost.

As pointed out in Mr. Bowman's response to PUB-CA-026, load shifting is but one of numerous benefits provided by smart meters:

1. The ability to remotely read meters;
2. Automatic outage detection and management;
3. The ability to remotely connect or disconnect service to customers;
4. Monitoring power quality;
5. Implementation of demand response programs such as Time-Of-Use ("TOU") rates;
6. Enablement of distributed energy generation;
7. The ability to provide customers personalized energy-saving tips and recommendations.
8. The ability to provide outage and power restoration notifications; and
9. Quicker notification of outages which could reduce response time."

It would appear that the only benefit that Newfoundland Power has attempted to quantify is demand response, identified as number 5 in the above list, and has failed to quantify the other eight benefits of smart meters. An additional benefit of smart meters is that they would provide essential information on customer consumption characteristics, negating the need to install special metering for future load research studies. It would avoid the embarrassing supply chain issues now being experienced by Newfoundland Power with its load research study. If Newfoundland Power believes that smart meters are not the metering system of choice in the industry, then why has it not provided a list of utilities that are now embarking on an AMR metering program like the one Newfoundland Power now has in place?

As stated in Mr. Bowman's response to PUB-CA-026ii, Narragansett Electric Company in Rhode Island indicates that its smart meter program has a benefit to cost ratio of 3.9. The cost of the program is expected to result in a total bill increase over the first five years of $2.46. This equates to about 5.6 cents Canadian per month over the first 5 years of the program. After that, bills would decrease. The potential benefits of smart meters are too good to ignore.

***Recommendation: The Board should direct Newfoundland Power to undertake a study on smart meters that assesses the costs and all benefits of smart meters so the Board and the parties are in a position to decide if smart meters are least cost compared to continuing with the "New Meters" and "Replacement Meters" capital programs that may lead to stranded investment. The study should be completed and filed with the Board by year-end 2024.***

5.2 Distribution Planning

As noted in his direct evidence (June 28, 2024 Transcript, pages 13 to 52), Mr. Bowman modified the Republic of Georgia's Distribution Code about 7 or 8 years ago. The distribution code covers in one document distribution Planning, Operations, Metering and Connections. By including all components of distribution in a single document transparency is significantly improved, as is the ability of the Board and the parties to understand and comment on these key areas relating to the provision of distribution service.

Newfoundland Power states in its Rebuttal Evidence (page 45) "*Newfoundland Power's current distribution planning processes adequately address all objectives that Mr. Bowman suggests are required to be met for a "distribution planning guideline." The 3 following documents satisfy a number of Mr. Bowman's stated objectives: the Distribution Planning Guidelines, which outline technical criteria and principles for planning the distribution system, including net metering, and the Service and Metering Guide, which outlines the Company's policies and procedures as well as technical requirements for establishing electrical service connection and metering to the system.*" Clearly they do not. The key component of the planning guide is the development of a 5-year distribution expansion plan. Mr. Bowman indicates that he reviewed Georgia's Distribution Code 7 or 8 years ago, but the Georgian distribution companies were developing 5-year distribution expansion plans long before Mr. Bowman conducted his review.

Ms. Greene asked Mr. Chubbs (June 28, 2024 Transcript, pages 19-20) "*Another topic like that, before we move on to operating costs, is electrification and again you mentioned it earlier as one of the challenges that is facing all utilities, what the impact of the grid will be of increasing customer demand because of the switch to electrification. Again, how is Newfoundland Power planning to address the impact of electrification growth on your system?*" Mr. Chubbs' response covered four pages, and none of the topics referenced Newfoundland Power's 5-year distribution expansion plan because it does not have one. If Newfoundland Power had a 5-year distribution expansion plan, the information would be readily available and Ms. Greene would not have had to ask the question.

An example of the value provided by a five-year distribution expansion plan is the Long Pond Substation. Newfoundland Power built the substation at a cost of $4.7 million in 2021, and charged the full amount to the University. Two years later, Newfoundland Power came in with another application seeking $3.3 million for a substation upgrade. The original $4.7 million cost was paid by the University because the new substation was considered a duplicate supply - all of the load could have been supplied by the existing MUN Substation making the LPD Substation superfluous, or redundant (at the request of the University). But two years later, the substation upgrade was needed because of an increase in load, presumably brought on by the electrification of the boilers. This raises two questions:

1. Should the decision to require the University to pay the full cost of the $4.6 million LPD substation be revisited since the LPD Substation is not a duplicate supply? Not all of the University load can be supplied from the MUN Substation. Should Newfoundland Power refund the $4.6 million back to the University because it was gained under false pretenses?

2. Given that the potential electrification of the boilers at the University has been known for some time, if Newfoundland Power had developed a 5-year distribution expansion plan, would the Long Pond Substation construction and expansion have been handled more efficiently and at a cost less than the $7.9 million expended?

A 5-year distribution expansion plan would have either answered, or avoided the need for, these questions. As stated in Mr. Bowman's Pre-filed Evidence (page 12) "Section 6 of the Electrical Power Control Act, 1994, chapter E-5.1 states with respect to Planning of future power supply:

1. The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.

2. The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe.

3. For the purpose of this section, the public utilities board may adopt those rules and procedures that it considers necessary or advisable to give effect to the subsection.

In the absence of a 5-year distribution expansion plan, the Board is unable to meet this responsibility.

***Recommendation: The Board should direct Newfoundland Power to develop a distribution planning guideline and 5-year distribution expansion plan that gives full consideration to costs, quantification of project risks and service improvements, the environment and government net-zero emissions efforts, the value customers place on service improvements, behind-the-meter alternatives and the potential for stranding of hard infrastructure alternatives. The Guideline should be developed by year-end 2024.***

## 5.3 Reliability

Mr. Chubbs "***feels***" that targeting a level of reliability that is 40% better than the Canadian average is least cost (June 26, 2024 Transcript, pages 95-96). He states "*the reliability of the electricity system is least cost for our customers.*" However, he offers no evidence to support the statement. Does the rest of the industry know that the optimum reliability level versus cost is a level that is 40% better than the Canadian average? In the July 27, 2024 Transcript (page 120) Mr. Comerford states "*I'm not aware of any detailed studies on that particular topic.*" Clearly, Newfoundland Power does not know what level of reliability meets the least cost criterion. Further, Newfoundland Power provides no evidence that other utilities are targeting a level of reliability that is 40% better than the Canadian average because it is least cost. Is the Board comfortable approving a reliability target that is 40% better than the Canadian average on the basis of an individual's feelings, or does it require evidence?

The Board should direct Newfoundland Power to quantify the cost incurred on behalf of its customers to improve reliability to a level that is 40% better than the Canadian average. This will help the Board decide if a target reliability level that is 0%, 20%, 40%, or 80% better than the Canadian average is least cost.

As pointed out in Mr. Bowman's Pre-filed Evidence (page 50) "*In the past, battery storage as a backup source of supply was prohibitively expensive. However, with the advent of electric vehicles, many electricity customers will have a battery storage device sitting in their driveways or garages. PUB-NP-054 forecasts a total of 6,197 cumulative EVs on the Island by 2028. With the addition of an inverter and an extension cord, a significant number of customers will have a source of backup supply during outages.*" Clearly, the value customers place on reliability of electricity service will be reduced with the availability of battery storage devices on site in the form of an electric vehicle.

To summarize, although customers have incurred a cost for reliability that is 40% better than the Canadian average, there is no evidence on the record that they place a value on this increased reliability commensurate with the increased cost. The benefit of Newfoundland Power's SAIDI performance that is 40% better than the Canadian average is likely worth very little to customers. In any event, Newfoundland Power has not provided convincing evidence that it is, particularly in light of the expected increase in the number of electric vehicles with battery storage. New facilities that are justified on the basis of reliability improvements may very well become stranded. The Consumer Advocate takes no exception to this scenario if Newfoundland Power and its shareholder cover all costs of stranded assets.

Finally, in Newfoundland Power's Rebuttal Evidence (page 40) it is stated "*Since the frequency of Newfoundland Power's customer outages is consistent with the Canadian average, Mr. Bowman's recommendation implies that the Company should slow its response to customer outages.*" There is no such implication. The Consumer Advocate and Mr. Bowman do ***not*** expect Newfoundland Power's senior management to react foolishly to a change in the target reliability. They should be expected to react appropriately, like all good utility managers. Since Newfoundland Power believes there is no incremental cost associated with maintaining current levels of reliability that are 40% better than the Canadian average, the Board should reduce Newfoundland Power's operating budget and its capital programs relating to technology and automation. Given that there is no incremental cost, reducing these budget items would not be expected to have a detrimental impact on reliability.

***Recommendation: The Board should direct Newfoundland Power to target a reliability level that is consistent with the Canadian average or otherwise submit evidence that a target reliability level that is 40% better than the Canadian average is consistent with the provision of least cost service. This report should be completed by year-end 2024.***

5.4 Is Memorial University a Public Utility?

Newfoundland Power's Rules and Regulations, paragraph 2(d) state "*The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part, except that the Customer may include the cost of Service in charges for the lease of space, or as part of the cost of other services provided by the Customer.*" Newfoundland Power was asked (CA-NP-123) "*Does Memorial University resell the service in whole or in part? Please explain.*" The response states "*Newfoundland Power is not aware of whether Memorial University resells the service.*" This response prompts the following questions:

1. Who is responsible for enforcing Newfoundland Power's Rules and Regulations? and,

2. Does Memorial University qualify as a public utility under the Public Utilities Act, Section 2(h) which defines a public utility as "*a person that owns, operates, manages or controls structures, equipment or facilities in the province for the production, generation, storage, transmission, delivery or provision of electric power, energy, water or heat, directly or indirectly, to or for the public or a corporation for compensation*"?

As noted in Mr. Bowman's Pre-filed Evidence (pages 35 and 36) "*It is understood that the Health Sciences Center at Memorial University is an acute care facility serving the people of the entire province, and that it is connected and shares services with the Janeway Children's Health and Rehabilitation Centre and the Dr. H. Bliss Murphy Cancer Centre. Given that various medical facilities are served by Memorial University that are important not only to the people of St. John's, but to all people in the province, might the hospital facilities be better represented if the University were categorized as a public utility and subjected to the same regulatory oversight as other public utilities in the province?*"

It is not clear who would be responsible if: 1) there were an outage affecting the medical facilities served by the University and people being treated at the medical facilities were injured as a result, and 2) there were a prolonged outage rendering the medical facilities inoperative for an extended period of time.

Further, it is understood that the University supplies numerous "businesses" within the complex besides the medical and academic facilities such as the "*Queen Elizabeth II Library, Bruneau Centre for Research and Innovation, Paton College and Macpherson College residence complexes, Burton's Pond Apartments, Campus Childcare Centre, and The Works recreation complex, comprising the Aquarena, Field House and other sports and recreation facilities.*"[92] The University appears to own and operate facilities that deliver power to commercial entities for compensation, at

[92] https://www.mun.ca/university-calendar/st-johns-campus/

least in the case of the residence complexes, the apartments and the childcare centre.

It is not clear who is responsible for deciding if the University is a public utility under current legislation, whether that be the Board, Newfoundland Power or the provincial government, but the issue should be given consideration as it is not clear who is responsible when things go wrong (e.g., reliability, power quality), and if the various entities within the University complex are receiving appropriate value in return for payment. Board oversight is needed if this is to be assured.

***Recommendation: The Board should direct Newfoundland Power to undertake a study to determine if Memorial University qualifies as a public utility under the Public Utilities Act.***

## 6. CONCLUSION AND RECOMMENDATIONS

The GRA is nothing more than an effort by Newfoundland Power to increase the profits of its shareholder while failing to bring its cost growth below the inflation rate and addressing other issues identified in the preceding. It is unfairly generous to the utility.

This submissions' recommendations, reproduced below, provide a basis for a balanced and fair treatment of consumers and the utility.

1. ***If the Board decides to allow Newfoundland Power to maintain an equity ratio of 45% then the allowed ROE should be set at 8.15%. A higher allowed ROE should entail a lower equity ratio.***

2. ***The band around the regulated rate of return on rate base should be set at +/- 6 basis points but with any contributions to the Excess Earnings Account capped at the point where further contributions would cause Newfoundland Power's ROE to be less than the allowed ROE.***

3. ***For 2025 and 2026, proposed operating expenses should be reduced by $2.5 million and $5 million, respectively.***

4. ***Beginning January 1, 2025, all future payments associated with Newfoundland Power's short-term incentive plan for executives should be paid by the shareholder.***

5. ***Beginning January 1, 2025, 20% of Newfoundland Power's executives' base salaries should be paid by the shareholder.***

6. ***The $2.773 million cost of insurance proposed for inclusion in Newfoundland Power's revenue requirement for 2025 and $2.935 million in 2026 should be disallowed.***

7. ***A new wholesale rate consistent with the Settlement Agreement dated June 12, 2024 should be implemented by January 1, 2025. Rates should be re-based according to the new wholesale rate as part of this GRA.***

8. ***The Board should direct Newfoundland Power to give high priority to the load research study that was agreed to by the parties at the 2022-2023 GRA.***

9. ***The Board should direct Newfoundland Power to work with the Consumer Advocate to:***
   a. ***Form a new General Service customer class (e.g., Rate 2.5) including customers served directly from the transmission system. This would include the two mines served from the RFD and LCV Substations, and Memorial University. The new class would be responsible for payment of their own connection costs and would not be responsible for paying distribution costs that are not used in their supply.***

   b. ***Make adjustments to the cost of service for General Service Rate 2.4 customers to account for the transfer of demand and costs to the new Rate 2.5 customer class.***

   c. ***Re-draft Newfoundland Power policies (Rates, Rules and Regulations and CIAC policy for General Service customers) to account for the new General Service customer class, and clarify that customers served directly from the transmission system will be directly responsible for payment of the costs of their connections.***

   ***This issue should be addressed now so it can be included as part of the Board's Order on this GRA.***

10. ***Rates for Street and Area Lighting class should be increased to 100% of the cost of supply. Use the resulting increase in revenues to reduce the proposed rate increase for other customer classes that are paying close to 110% of the cost of supply.***

11. ***The Board should direct Newfoundland Power rate specialists to work with the Consumer Advocate to alter the charges in current rate structures to better reflect marginal costs. The revised rates should be included in the Board's decision on this GRA.***

12. ***The Board should direct Newfoundland Power rate specialists to work with the Consumer Advocate to alter the charges in current optional rates to better reflect marginal costs. The revised optional rates should be included in the Board's decision on this GRA.***

13. ***The Board should direct Newfoundland Power to undertake a study on smart meters that assesses the costs and <u>all</u> benefits of smart meters so the Board and the parties are in a position to decide if smart meters are least cost compared to continuing with the "New Meters" and "Replacement Meters" capital programs that may lead to stranded investment. The study should be completed and filed with the Board by year-end 2024.***

14. ***The Board should direct Newfoundland Power to develop a distribution planning guideline and 5-year distribution expansion plan that gives full consideration to costs, quantification of project risks and service improvements, the environment and government net-zero emissions efforts, the value customers place on service improvements, behind-the-meter***

*alternatives and the potential for stranding of hard infrastructure alternatives. The Guideline should be developed by year-end 2024.*

***15. The Board should direct Newfoundland Power to target a reliability level that is consistent with the Canadian average or otherwise submit evidence that a target reliability level that is 40% better than the Canadian average is consistent with the provision of least cost service. This report should be completed by year-end 2024.***

***16. The Board should direct Newfoundland Power to undertake a study to determine if Memorial University qualifies as a public utility under the Public Utilities Act.***

Please contact the undersigned if you have any questions on this submission.

Yours truly,

**Dennis Browne, KC**
**Consumer Advocate**

Encl.
/jm

cc

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## ATTACHMENT A

## EXCERPTS FROM DUKE ENERGY'S 2022 10-K

Duke Energy was incorporated on May 3, 2005, and is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the FERC and other regulatory agencies listed below. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also Subsidiary Registrants, including Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont. When discussing Duke Energy's consolidated financial information, it necessarily includes the results of its separate Subsidiary Registrants, which along with Duke Energy, are collectively referred to as the Duke Energy Registrants.

The Duke Energy Registrants electronically file reports with the SEC, including Annual Reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to such reports...

The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at sec.gov. Additionally, information about the Duke Energy Registrants, including reports filed with the SEC, is available through Duke Energy's website...

Duke Energy's segment structure includes two reportable business segments: Electric Utilities and Infrastructure (EU&I) and Gas Utilities and Infrastructure (GU&I). The remainder of Duke Energy's operations is presented as Other. Commercial Renewables is reported as discontinued operations and is no longer a reportable segment beginning in the fourth quarter of 2022...

### ELECTRIC UTILITIES AND INFRASTRUCTURE

EU&I conducts operations primarily through the regulated public utilities of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana and Duke Energy Ohio. EU&I provides retail electric service through the generation, transmission, distribution and sale of electricity to approximately 8.2 million customers within the Southeast and Midwest regions of the U.S. The service territory is approximately 92,000 square miles across six states with a total estimated population of 26 million. The operations include electricity sold wholesale to municipalities, electric cooperative utilities and other load-serving entities.

During 2021, Duke Energy executed an agreement providing for an investment by an affiliate of GIC in Duke Energy Indiana in exchange for a 19.9% minority interest issued by Duke Energy Indiana Holdco, LLC, the holding company for Duke Energy Indiana. The transaction was completed following two closings. Additionally, in November 2022, Duke Energy committed to a plan to sell the Commercial Renewables business segment, excluding the offshore wind contract for Carolina Long Bay, which was moved to EU&I. See Note 2 to the Consolidated Financial Statements, "Dispositions," for additional information.

EU&I is also a joint owner in certain electric transmission projects. EU&I has a 50% ownership interest in DATC, a partnership with American Transmission Company, formed to design, build and operate transmission infrastructure. DATC owns 72% of the transmission service rights to Path 15, an 84-mile transmission line in central California. EU&I also has a 50% ownership interest in Pioneer, which builds, owns and operates electric transmission facilities in North America...

The electric operations and investments in projects are subject to the rules and regulations of the FERC, the NRC, the NCUC, the PSCSC, the FPSC, the IURC, the PUCO and the KPSC...

**Competition**

***Retail***

EU&I's businesses operate as the sole supplier of electricity within their service territories, with the exception of Ohio, which has a competitive electricity supply market for generation service. EU&I owns and operates facilities necessary to generate, transmit, distribute and sell electricity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable electricity at fair prices.

In Ohio, EU&I conducts competitive auctions for electricity supply. The cost of energy purchased through these auctions is recovered from retail customers. EU&I earns retail margin in Ohio on the transmission and distribution of electricity, but not on the cost of the underlying energy.

Competition in the regulated electric distribution business is primarily from the development and deployment of alternative energy sources including on-site generation from industrial customers and distributed generation, such as private solar, at residential, general service and/or industrial customer sites.

***Wholesale***

Duke Energy competes with other utilities and merchant generators for bulk power sales, sales to municipalities and cooperatives and wholesale transactions under primarily cost-based contracts approved by FERC. The principal factors in competing for these sales are availability of capacity and power, reliability of service and price. Prices are influenced primarily by market conditions and fuel costs.

Increased competition in the wholesale electric utility industry and the availability of transmission access could affect EU&I's load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of EU&I to attract new customers and to retain existing customers.

## Energy Capacity and Resources

EU&I owns approximately 49,870 MW of generation capacity...

Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Factors that could cause EU&I to purchase power for its customers may include, but are not limited to, generating plant outages, extreme weather conditions, generation reliability, demand growth and price. EU&I has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy and reliability of power supply.

EU&I's generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve retail customers. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements.

## Sources of Electricity

EU&I relies principally on natural gas, nuclear fuel and coal for its generation of electricity...

### *Natural Gas and Fuel Oil*

Natural gas and fuel oil supply, transportation and storage for EU&I's generation fleet is purchased under standard industry agreements from various suppliers, including Piedmont. Natural gas supply agreements typically provide for a percentage of forecasted burns being procured over time, with varied expiration dates. Electric Utilities and Infrastructure believes it has access to an adequate supply of natural gas and fuel oil for the reasonably foreseeable future.

EU&I has certain dual-fuel generating facilities that can operate utilizing both natural gas and fuel oil. The cost of EU&I's natural gas and fuel oil is fixed price or determined by published market prices as reported in certain industry publications, plus any transportation and freight costs. Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana use derivative instruments to manage a portion of their exposure to price fluctuations for natural gas. Duke Energy Florida has temporarily agreed to not hedge natural gas prices, but retains an ability to propose hedging again in annual fuel docket filings.

EU&I has firm interstate and intrastate natural gas transportation agreements and storage agreements in place to support generation needed for load requirements. EU&I may purchase additional shorter-term natural gas transportation and utilize natural gas interruptible transportation agreements to support generation needed for load requirements. The EU&I natural gas plants are served by various supply zones and multiple pipelines.

***Nuclear***

The industrial processes for producing nuclear generating fuel generally involve the mining and milling of uranium ore to produce uranium concentrates and services to convert, enrich and fabricate fuel assemblies.

EU&I has contracted for uranium materials and services to fuel its nuclear reactors. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. EU&I staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements in the near term and decreasing portions of its fuel requirements over time thereafter. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases. Due to the technical complexities of changing suppliers of fuel fabrication services, EU&I generally source these services to a single domestic supplier on a plant-by-plant basis using multiyear contracts.

EU&I has entered into fuel contracts that cover 100% of its uranium concentrates through at least 2024, 100% of its conversion services through at least 2026, 100% of its enrichment services through at least 2026, and 100% of its fabrication services requirements for these plants through at least 2027. For future requirements not already covered under long-term contracts, EU&I believes it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services.

***Coal***

EU&I meets its coal demand through a portfolio of long-term purchase contracts and short-term spot market purchase agreements. Large amounts of coal are purchased under long-term contracts with mining operators who mine both underground and at the surface. EU&I uses spot market purchases to meet coal requirements not met by long-term contracts. Expiration dates for its long-term contracts, which may have various price adjustment provisions and market reopeners, range from 2023 to 2027 for Duke Energy Carolinas and Duke Energy Indiana, 2023 to 2024 for Duke Energy Progress and 2023 to 2025 for Duke Energy Florida and Duke Energy Ohio. EU&I expects to renew these contracts or enter into similar contracts with other suppliers as existing contracts expire, though prices will fluctuate over time as coal markets change. EU&I has an adequate supply of coal under contract to meet its risk management guidelines regarding projected future consumption. As a result of volatility in natural gas prices and the associated impacts on coal-fired dispatch within the generation fleet, coal inventories will continue to fluctuate. EU&I continues to actively manage its portfolio and has worked with suppliers to obtain increased flexibility in its coal contracts.

Coal purchased for the Carolinas is primarily produced from mines in Central Appalachia, Northern Appalachia and the Illinois Basin. Coal purchased for Florida is primarily produced from mines in the Illinois Basin. Coal purchased for Kentucky is produced from mines along the Ohio River in Illinois, Ohio, West Virginia and Pennsylvania. Coal purchased for Indiana is primarily produced in Indiana and Illinois. There are adequate domestic coal reserves to serve EU&I's coal generation needs through end of life. The current average sulfur content of coal purchased by Electric Utilities and Infrastructure is between 0.5% and 3.5% for Duke Energy Carolinas and Duke Energy Progress, and between 0.5% and 4% for Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana. EU&I's environmental controls, in combination with the use of sulfur dioxide (SO2) emission allowances, enable EU&I to satisfy current SO2 emission limitations for its existing facilities.

***Purchased Power***

EU&I purchases a portion of its capacity and system requirements through purchase obligations, leases and purchase capacity contracts. EU&I believes it can obtain adequate purchased power capacity to meet future system load needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected...

**Inventory**

EU&I must maintain an adequate stock of fuel and materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2022, the inventory balance for EU&I was approximately $3.4 billion...

**Ash Basin Management**

During 2015, EPA issued regulations related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the Resource Conservation and Recovery Act (RCRA) and apply to electric generating sites with new and existing landfills and new and existing surface impoundments and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments (ash basins or impoundments) will continue to be regulated by existing state laws, regulations and permits, such as the North Carolina Coal Ash Management Act of 2014 (Coal Ash Act).

EU&I has and will periodically submit to applicable authorities required site-specific coal ash impoundment remediation or closure plans. Closure plans must be approved and all associated permits issued before any work can begin. Closure activities have begun in all of Duke Energy's jurisdictions. Excavation began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to appropriate engineered off-site or on-site lined landfills or for reuse in an approved beneficial application. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites where CCR management is required, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced.

The EPA CCR rule and the Coal Ash Act leave the decision on cost recovery determinations related to closure of coal ash surface impoundments to the normal ratemaking processes before utility regulatory commissions. Duke Energy's electric utilities have included compliance costs associated with federal and state requirements in their respective rate proceedings. During 2017, Duke Energy Carolinas' and Duke Energy Progress' wholesale contracts were amended to include the recovery of expenditures related to AROs for the closure of coal ash basins. The amended contracts have retail disallowance parity or provisions limiting challenges to CCR cost recovery actions at FERC. FERC approved the amended wholesale rate schedules in 2017...

**Nuclear Matters**

Duke Energy owns, wholly or partially, 11 operating nuclear reactors located at six operating stations. The Crystal River Unit 3 permanently ceased operation in February 2013. Nuclear insurance includes: nuclear liability coverage; property damage coverage; nuclear accident decontamination and premature decommissioning coverage; and accidental outage coverage for losses in the event of a major accidental outage. Joint owners reimburse Duke Energy for certain expenses associated with nuclear insurance in accordance with joint owner agreements. The Price-Anderson Act requires plant owners to provide for public nuclear liability claims resulting from nuclear incidents to the maximum total financial protection liability, which is approximately $13.7 billion...

Duke Energy has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate each plant safely. The NCUC, PSCSC and FPSC require Duke Energy to update their cost estimates for decommissioning their nuclear plants every five years.

The following table summarizes the fair value of NDTF investments and the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2018 or 2019 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination...

The NCUC, PSCSC, FPSC and FERC have allowed EU&I to recover estimated decommissioning costs through retail and wholesale rates over the expected remaining service periods of their nuclear stations. EU&I believes the decommissioning costs being recovered through rates, when coupled with the existing fund balances and expected fund earnings, will be sufficient to provide for the cost of future decommissioning. For additional information, see Note 10 to the Consolidated Financial Statements, "Asset Retirement Obligations."

The Nuclear Waste Policy Act of 1982 (as amended) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The government has not yet developed a storage facility or disposal capacity, so EU&I will continue to store spent fuel on its reactor sites.

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE terminated the project to license and develop a geologic repository at Yucca Mountain, Nevada in 2010, and is currently taking no action to fulfill its responsibilities to dispose of spent fuel.

Until the DOE begins to accept the spent nuclear fuel, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida will continue to safely manage their spent nuclear fuel. Under current regulatory guidelines, Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license. With certain modifications and approvals by the NRC to expand the on-site dry cask storage facilities, spent nuclear fuel dry storage facilities will be sufficient to provide storage space of spent fuel through the expiration of the operating licenses, including any license renewals, for Brunswick, Catawba, McGuire, Oconee and Robinson. Crystal River Unit 3 ceased operation in 2013 and was placed in a SAFSTOR condition in January 2018. As of January 2018, all spent fuel at Crystal River Unit 3 has been transferred from the spent fuel pool to dry storage at an on-site independent spent fuel storage installation. During 2020, the NRC and the FPSC approved an agreement to transfer ownership of spent fuel for Crystal River Unit 3 to a third party...

The nuclear power industry faces uncertainties with respect to the cost and long-term availability of disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, capital outlays for modifications and new plant construction.

EU&I is subject to the jurisdiction of the NRC for the design, construction and operation of its nuclear generating facilities. The following table includes the current year of expiration of nuclear operating licenses for nuclear stations in operation. In June 2021, Duke Energy Carolinas filed a subsequent license renewal application for the Oconee Nuclear Station (ONS) with the U.S. Nuclear Regulatory Commission to renew ONS's operating license for an additional 20 years. Duke Energy has announced its intention to seek 20-year operating license renewals for each of the reactors it operates in Duke Energy Carolinas and Duke Energy Progress...

The NRC has acknowledged permanent cessation of operation and permanent removal of fuel from the reactor vessel at Crystal River Unit 3. Therefore, the license no longer authorizes operation of the reactor. For additional information on nuclear decommissioning activity, see Notes 4 and 10 to the Consolidated Financial Statements, "Regulatory Matters" and "Asset Retirement Obligations," respectively.

## Regulation

### *State*

The state electric utility commissions approve rates for Duke Energy's retail electric service within their respective states. The state electric utility commissions, to varying degrees, have authority over the construction and operation of EU&I's generating facilities. CPCNs issued by the state electric utility commissions, as applicable, authorize EU&I to construct and operate its electric facilities and to sell electricity to retail and wholesale customers. Prior approval from the relevant state electric utility commission is required for the entities within EU&I to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus earn a reasonable rate of return on its invested capital, including equity.

In addition to rates approved in base rate cases, each of the state electric utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over or under-recovered costs, are prudent.

Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by EU&I. EU&I uses coal, hydroelectric, natural gas, oil, renewable generation and nuclear fuel to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of EU&I, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from customers can adversely impact the timing of cash flows of EU&I...

Additionally, in January 2021, Duke Energy Florida filed a settlement agreement with the FPSC that will allow annual increases to its base rates, an agreed upon return on equity ("ROE") and includes a base rate stay-out provision through 2024, among other provisions. The FPSC approved the 2021 Settlement on May 4, 2021, issuing an order on June 4, 2021. Revised customer rates became effective January 1, 2022, with subsequent base rate increases effective January 1, 2023, and January 1, 2024...

***Federal***

The FERC approves EU&I's cost-based rates for electric sales to certain power and transmission wholesale customers. Regulations of FERC and the state electric utility commissions govern access to regulated electric and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with EU&I.

***RTOs***

PJM and MISO are the ISOs and FERC-approved RTOs for the regions in which Duke Energy Ohio and Duke Energy Indiana operate. PJM and MISO operate energy, capacity and other markets, and control the day-to-day operations of bulk power systems through central dispatch.

Duke Energy Ohio is a member of PJM and Duke Energy Indiana is a member of MISO. Transmission owners in these RTOs have turned over control of their transmission facilities and their transmission systems are currently under the dispatch control of the RTOs. Transmission service is provided on a regionwide, open-access basis using the transmission facilities of the RTO members at rates based on the costs of transmission service.

### *Environmental*

EU&I is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see "Environmental Matters" in this section. See the "Other Matters" section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energy's operations.

## GAS UTILITIES AND INFRASTRUCTURE

GU&I conducts natural gas operations primarily through the regulated public utilities of Piedmont, Duke Energy Ohio and Duke Energy Kentucky. The natural gas operations are subject to the rules and regulations of the NCUC, PSCSC, PUCO, KPSC, TPUC, PHMSA and the FERC. GU&I serves residential, commercial, industrial and power generation natural gas customers, including customers served by municipalities who are wholesale customers. GU&I has over 1.6 million total customers, including 1.1 million customers located in North Carolina, South Carolina and Tennessee, and an additional 550,000 customers located within southwestern Ohio and northern Kentucky. In the Carolinas, Ohio and Kentucky, the service areas are comprised of numerous cities, towns and communities. In Tennessee, the service area is the metropolitan area of Nashville. The following map shows the service territory and investments in operating pipelines for GU&I as of December 31, 2022...

The number of residential, commercial and industrial customers within the GU&I service territory is expected to increase over time. Average usage per residential customer is expected to remain flat or decline for the foreseeable future; however, decoupled rates in North Carolina and various rate design mechanisms in other jurisdictions partially mitigate the impact of the declining usage per customer on overall profitability.

GU&I also has investments in various pipeline transmission projects, renewable natural gas projects and natural gas storage facilities.

### Natural Gas for Retail Distribution

GU&I is responsible for the distribution of natural gas to retail customers in its North Carolina, South Carolina, Tennessee, Ohio and Kentucky service territories. GU&I's natural gas procurement strategy is to contract primarily with major and independent producers and marketers for natural gas supply. It also purchases a diverse portfolio of transportation and storage service from interstate pipelines. This strategy allows GU&I to assure reliable natural gas supply and transportation for its firm customers during peak winter conditions. When firm pipeline services or contracted natural gas supplies are temporarily not needed due to market demand fluctuations, GU&I may release these services and supplies in the secondary market under FERC-approved capacity release provisions or make wholesale secondary market sales. In 2022, firm supply purchase commitment agreements provided 100% of the natural gas supply for both Piedmont and Duke Energy Ohio. Approximately 90% of forecasted demand was under contract prior to the winter heating season, with firm daily spot purchases making up the balance.

**Impact of Weather**

GU&I revenues are generally protected from the impact of weather fluctuations due to the regulatory mechanisms that are available in most service territories. In North Carolina, margin decoupling provides protection from both weather and other usage variations like conservation for residential and small and medium general service customers. Margin decoupling provides a set margin per customer independent of actual usage. In South Carolina, Tennessee and Kentucky, weather normalization adjusts revenues either up or down depending on how much warmer or colder than normal a given month has been. Weather normalization adjustments occur from November through March in South Carolina, from October through April in Tennessee and from November through April in Kentucky. Duke Energy Ohio collects most of its non-fuel revenue through a fixed monthly charge that is not impacted by usage fluctuations that result from weather changes or conservation.

**Competition**

GU&I's businesses operate as the sole provider of natural gas service within their retail service territories. GU&I owns and operates facilities necessary to transport and distribute natural gas. GU&I earns retail margin on the transmission and distribution of natural gas and not on the cost of the underlying commodity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable natural gas service at fair prices.

In residential, commercial and industrial customer markets, natural gas distribution operations compete with other companies that supply energy, primarily electric companies, propane and fuel oil dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. A significant competitive factor is price. GU&I's primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas or decreases in the price of other energy sources could negatively impact competitive position by decreasing the price benefits of natural gas to the consumer. In the case of industrial customers, such as manufacturing plants, adverse economic or market conditions, including higher natural gas costs, could cause these customers to suspend business operations or to use alternative sources of energy in favor of energy sources with lower per-unit costs.

Higher natural gas costs or decreases in the price of other energy sources may allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety and other non-price factors. Technological improvements in other energy sources and events that impair the public perception of the non-price attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business, adversely affecting our earnings.

**Natural Gas Investments**

Duke Energy, through its GU&I segment, has a 7.5% equity ownership interest in Sabal Trail. Sabal Trail is a joint venture that owns the Sabal Trail Natural Gas Pipeline (Sabal Trail pipeline) to transport natural gas to Florida, regulated by FERC. The Sabal Trail Phase I mainline was placed into service in July 2017 and traverses Alabama, Georgia and Florida. The remaining lateral line to the Duke Energy Florida's Citrus County CC was placed into service in March 2018. Phase II of Sabal Trail went into service in May 2020, adding approximately 200,000 Dth of capacity to the Sabal Trail pipeline.

Duke Energy, through its GU&I segment, has a 47% equity ownership interest in ACP, which planned to build the ACP pipeline, an approximately 600-mile interstate natural gas pipeline. The ACP pipeline was intended to transport diverse natural gas supplies into southeastern markets and would be regulated by FERC. Dominion Energy owns 53% of ACP and was contracted to construct and operate the ACP pipeline upon completion. On July 5, 2020, Dominion announced a sale of substantially all of its natural gas transmission and storage segment assets, which were critical to the ACP pipeline. Further, permitting delays and legal challenges had materially affected the timing and cost of the pipeline. As a result, Duke Energy determined that they would no longer invest in the construction of the ACP pipeline.

Duke Energy, also through its GU&I segment, has investments in various renewable natural gas joint ventures.

GU&I has a 21.49% equity ownership interest in Cardinal, an intrastate pipeline located in North Carolina regulated by the NCUC, a 45% equity ownership in Pine Needle, an interstate liquefied natural gas storage facility located in North Carolina and a 50% equity ownership interest in Hardy Storage, an underground interstate natural gas storage facility located in Hardy and Hampshire counties in West Virginia. Pine Needle and Hardy Storage are regulated by FERC.

KO Transmission Company (KO Transmission), a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value...

**Inventory**

GU&I must maintain adequate natural gas inventory in order to provide reliable delivery to customers. As of December 31, 2022, the inventory balance for GU&I was $185 million...

**Regulation**

***State***

The state gas utility commissions approve rates for Duke Energy's retail natural gas service within their respective states. The state gas utility commissions, to varying degrees, have authority over the construction and operation of GU&I's natural gas distribution facilities. CPCNs issued by the state gas utility commissions or other government agencies, as applicable, authorize GU&I to construct and operate its natural gas distribution facilities and to sell natural gas to retail and wholesale customers. Prior approval from the relevant state gas utility commission is required for GU&I to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its invested capital, including equity.

In addition to amounts collected from customers through approved base rates, each of the state gas utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over- or under-recovered costs, are prudent.

Natural gas costs are eligible for recovery by GU&I. Due to the associated regulatory treatment and the method allowed for recovery, changes in natural gas costs from year to year have no material impact on operating results of GU&I, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for natural gas and recovery from customers can adversely impact the timing of cash flows of GU&I...

GU&I has an IMR mechanism in North Carolina designed to separately track and recover certain costs associated with capital investments incurred to comply with federal pipeline safety and integrity programs. Piedmont has withdrawn from the Tennessee IMR mechanism subsequent to the authorization of the Tennessee Annual Review Mechanism effective January 2022...

In Ohio, GU&I has a Capital Expenditure Program Rider (CEP Rider) designed to recover costs between rate cases on PUCO approved capital expenditures. Duke Energy Ohio submits a filing each year for incremental investments to increase the revenue requirement up to the cap of approximately $7 million. The cumulative investment under the CEP Rider is $359 million with total annual revenue requirement of $70 million...

### *Federal*

GU&I is subject to various federal regulations, including regulations that are particular to the natural gas industry. These federal regulations include but are not limited to the following:

- Regulations of the FERC affect the certification and siting of new interstate natural gas pipeline projects, the purchase and sale of, the prices paid for, and the terms and conditions of service for the interstate transportation and storage of natural gas.
- Regulations of the PHMSA affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems.
- Regulations of the EPA relate to the environment including proposed air emissions regulations that would expand to include emissions of methane.

Regulations of the FERC and the state gas utility commissions govern access to regulated natural gas and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with Gas Utilities and Infrastructure.

### *Environmental*

GU&I is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see "Environmental Matters" in this section. See "Other Matters" section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energy's operations.

## OTHER

The remainder of Duke Energy's operations is presented as Other. While it is not a business segment, Other primarily includes interest expense on holding company debt, unallocated corporate costs, amounts related to certain companywide initiatives and contributions made to the Duke Energy Foundation. Other also includes Bison and an investment in NMC.

The Duke Energy Foundation is a nonprofit organization funded by Duke Energy shareholders that makes charitable contributions to selected nonprofits and government subdivisions.

Bison, a wholly owned subsidiary of Duke Energy, is a captive insurance company with the principal activity of providing Duke Energy subsidiaries with indemnification for financial losses primarily related to property, workers' compensation and general liability.

Duke Energy owns a 17.5% equity interest in NMC. The joint venture company has production facilities in Jubail, Saudi Arabia, where it manufactures certain petrochemicals and plastics. The company annually produces approximately 1 million metric tons each of MTBE and methanol and has the capacity to produce 50,000 metric tons of polyacetal. The main feedstocks to produce these products are natural gas and butane. Duke Energy records the investment activity of NMC using the equity method of accounting and retains 25% of NMC's board of directors' representation and voting rights...

**DUKE ENERGY CAROLINAS**

Duke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas' service area covers approximately 24,000 square miles and supplies electric service to 2.8 million residential, commercial and industrial customers...Duke Energy Carolinas is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Substantially all of Duke Energy Carolinas' operations are regulated and qualify for regulatory accounting. Duke Energy Carolinas operates one reportable business segment, EU&I...

**PROGRESS ENERGY**

Progress Energy is a public utility holding company primarily engaged in the regulated electric utility business and is subject to regulation by the FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. When discussing Progress Energy's financial information, it necessarily includes the results of Duke Energy Progress and Duke Energy Florida.

Substantially all of Progress Energy's operations are regulated and qualify for regulatory accounting. Progress Energy operates one reportable business segment, EU&I...

**DUKE ENERGY PROGRESS**

Duke Energy Progress is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Progress' service area covers approximately 29,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers...Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Substantially all of Duke Energy Progress' operations are regulated and qualify for regulatory accounting. Duke Energy Progress operates one reportable business segment, EU&I...

**DUKE ENERGY FLORIDA**

Duke Energy Florida is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Florida's service area covers approximately 13,000 square miles and supplies electric service to approximately 1.9 million residential, commercial and industrial customers...Duke Energy Florida is subject to the regulatory provisions of the FPSC, NRC and FERC.

Substantially all of Duke Energy Florida's operations are regulated and qualify for regulatory accounting. Duke Energy Florida operates one reportable business segment, EU&I...

**DUKE ENERGY OHIO**

Duke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, in the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio also conducts competitive auctions for retail electricity supply in Ohio whereby recovery of the energy price is from retail customers. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky. References herein to Duke Energy Ohio include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, KPSC, PHMSA and FERC.

Duke Energy Ohio's service area covers approximately 3,000 square miles and supplies electric service to approximately 900,000 residential, commercial and industrial customers and provides transmission and distribution services for natural gas to approximately 550,000 customers...

KO Transmission, a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value.

Substantially all of Duke Energy Ohio's operations are regulated and qualify for regulatory accounting. Duke Energy Ohio has two reportable segments, EU&I and GU&I...

**DUKE ENERGY INDIANA**

Duke Energy Indiana is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Indiana. Duke Energy Indiana's service area covers 23,000 square miles and supplies electric service to 890,000 residential, commercial and industrial customers...Duke Energy Indiana is subject to the regulatory provisions of the IURC and FERC.

In 2021, Duke Energy executed an agreement providing for an investment in Duke Energy Indiana by GIC. The transaction was completed following two closings. For additional information, see Note 2 to the Consolidated Financial Statements, "Dispositions."

Substantially all of Duke Energy Indiana's operations are regulated and qualify for regulatory accounting. Duke Energy Indiana operates one reportable business segment, EU&I...

**PIEDMONT**

Piedmont is a regulated public utility primarily engaged in the distribution of natural gas to over 1.1 million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including customers served by municipalities who are wholesale customers...Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, TPUC, PHMSA and FERC.

Substantially all of Piedmont's operations are regulated and qualify for regulatory accounting. Piedmont operates one reportable business segment, GU&I...

**ITEM 1A. RISK FACTORS**

In addition to other disclosures within this Form 10-K, including "Management's Discussion and Analysis of Financial Condition and Results of Operations – Matters Impacting Future Results" for each registrant in Item 7, and other documents filed with the SEC from time to time, the following factors should be considered in evaluating Duke Energy and its subsidiaries. Such factors could affect actual results of operations and cause results to differ substantially from those currently expected or sought. Unless otherwise indicated, risk factors discussed below generally relate to risks associated with all of the Duke Energy Registrants. Risks identified at the Subsidiary Registrant level are generally applicable to Duke Energy.

**BUSINESS STRATEGY RISKS**

**Duke Energy's future results could be adversely affected if it is unable to implement its business strategy including achieving its carbon emissions reduction goals.**

Duke Energy's results of operations depend, in significant part, on the extent to which it can implement its business strategy successfully. Duke Energy's clean energy transition, which includes achieving net-zero carbon emissions from electricity generation by 2050, modernizing the regulatory construct, transforming the customer experience, and digital transformation, is subject to business, policy, regulatory, technology, economic and competitive uncertainties and contingencies, many of which are beyond its control and may make those goals difficult to achieve.

Federal or state policies could be enacted that restrict the availability of fuels or generation technologies, such as natural gas or nuclear power, that enable Duke Energy to reduce its carbon emissions. Supportive policies may be needed to facilitate the siting and cost recovery of transmission and distribution upgrades needed to accommodate the build out of large volumes of renewables and energy storage. Further, the approval of our state regulators will be necessary for the company to continue to retire existing carbon emitting assets or make investments in new generating capacity. The company may be constrained by the ability to procure resources or labor needed to build new generation at a reasonable price as well as to construct projects on time. In addition, new technologies that are not yet commercially available or are unproven at utility scale will likely be needed including new resources capable of following electric load over long durations such as advanced nuclear, hydrogen and long-duration storage, If these technologies are not developed or are not available at reasonable prices, or if we invest in early stage technologies that are then supplanted by technological breakthroughs, Duke Energy's ability to achieve a net-zero target by 2050 at a cost-effective price could be at risk.

Achieving our carbon reduction goals will require continued operation of our existing carbon-free technologies including nuclear and renewables. The rapid transition to and expansion of certain low-carbon resources, such as renewables without cost-effective storage, may challenge our ability to meet customer expectations of reliability in a carbon constrained environment. Our nuclear fleet is central to our ability to meet these objectives and customer expectations. We are continuing to seek to renew the operating licenses of the 11 reactors we operate at six nuclear stations for an additional 20 years, extending their operating lives to and beyond midcentury. Failure to receive approval from the NRC for the relicensing of any of these reactors could affect our ability to achieve a net-zero target by 2050.

As a consequence, Duke Energy may not be able to fully implement or realize the anticipated results of its energy transition strategy, which may have an adverse effect on its financial condition.

## REGULATORY, LEGISLATIVE AND LEGAL RISKS

**The Duke Energy Registrants' regulated utility revenues, earnings and results of operations are dependent on state legislation and regulation that affect electric generation, electric and natural gas transmission, distribution and related activities, which may limit their ability to recover costs.**

The Duke Energy Registrants' regulated electric and natural gas utility businesses are regulated on a cost-of-service/rate-of-return basis subject to statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Florida, Ohio, Tennessee, Indiana and Kentucky. If the Duke Energy Registrants' regulated utility earnings exceed the returns established by the state utility commissions, retail electric and natural gas rates may be subject to review and possible reduction by the commissions, which may decrease the Duke Energy Registrants' earnings. Additionally, if regulatory or legislative bodies do not allow recovery of costs incurred in providing service, or do not do so on a timely basis, the Duke Energy Registrants' earnings could be negatively impacted. Differences in regulation between jurisdictions with concurrent operations, such as North Carolina and South Carolina in Duke Energy Carolinas' and Duke Energy Progress' service territory, may also result in failure to recover costs.

If legislative and regulatory structures were to evolve in such a way that the Duke Energy Registrants' exclusive rights to serve their regulated customers were eroded, their earnings could be negatively impacted. Federal and state regulations, laws, commercialization and reduction of costs and other efforts designed to promote and expand the use of EE measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could reduce recovery of fixed costs in Duke Energy service territories or result in customers leaving the electric distribution system and an increase in customer net energy metering, which allows customers with private solar to receive bill credits for surplus power at the full retail amount. Over time, customer adoption of these technologies could result in Duke Energy not being able to fully recover the costs and investment in generation.

State regulators have approved various mechanisms to stabilize natural gas utility margins, including margin decoupling in North Carolina and rate stabilization in South Carolina. State regulators have approved other margin stabilizing mechanisms that, for example, allow for recovery of margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may otherwise directly access natural gas supply through their own connection to an interstate pipeline. If regulators decided to discontinue the Duke Energy Registrants' use of tariff mechanisms, it would negatively impact results of operations, financial position and cash flows. In addition, regulatory authorities also review whether natural gas costs are prudently incurred and can disallow the recovery of a portion of natural gas costs that the Duke Energy Registrants seek to recover from customers, which would adversely impact earnings.

**The rates that the Duke Energy Registrants' regulated utility businesses are allowed to charge are established by state utility commissions in rate case proceedings, which may limit their ability to recover costs and earn an appropriate return on investment.**

The rates that the Duke Energy Registrants' regulated utility businesses are allowed to charge significantly influences the results of operations, financial position and cash flows of the Duke Energy Registrants. The regulation of the rates that the regulated utility businesses charge customers is determined, in large part, by state utility commissions in rate case proceedings. Negative decisions made by these regulators, or by any court on appeal of a rate case proceeding, have, and in the future could have, a material adverse effect on the Duke Energy Registrants' results of operations, financial position or cash flows and affect the ability of the Duke Energy Registrants to recover costs and an appropriate return on the significant infrastructure investments being made.

**Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect the Duke Energy Registrants' results of operations, financial position or cash flows and their utility businesses.**

Increased competition resulting from deregulation or restructuring legislation could have a significant adverse impact on the Duke Energy Registrants' results of operations, financial position or cash flows and their utility businesses. If the retail jurisdictions served by the Duke Energy Registrants become subject to deregulation, the impairment of assets, loss of retail customers, lower profit margins or increased costs of capital, and recovery of stranded costs could have a significant adverse financial impact on the Duke Energy Registrants. Stranded costs primarily include the generation assets of the Duke Energy Registrants whose value in a competitive marketplace may be less than their current book value, as well as above-market purchased power commitments from QFs from whom the Duke Energy Registrants are legally obligated to purchase energy at an avoided cost rate under PURPA. The Duke Energy Registrants cannot predict the extent and timing of entry by additional competitors into the electric markets. The Duke Energy Registrants cannot predict if or when they will be subject to changes in legislation or regulation, nor can they predict the impact of these changes on their results of operations, financial position or cash flows.

**The Duke Energy Registrants' businesses are subject to extensive federal regulation and a wide variety of laws and governmental policies, including taxes and environmental regulations, that may change over time in ways that affect operations and costs.**

The Duke Energy Registrants are subject to regulations under a wide variety of U.S. federal and state regulations and policies, including by FERC, NRC, EPA and various other federal agencies as well as the North American Electric Reliability Corporation. Regulation affects almost every aspect of the Duke Energy Registrants' businesses, including, among other things, their ability to: take fundamental business management actions; determine the terms and rates of transmission and distribution services; make acquisitions; issue equity or debt securities; engage in transactions with other subsidiaries and affiliates; and pay dividends upstream to the Duke Energy Registrants. Changes to federal regulations are continuous and ongoing. There can be no assurance that laws, regulations and policies will not be changed in ways that result in material modifications of business models and objectives or affect returns on investment by restricting activities and products, subjecting them to escalating costs, causing delays, or prohibiting them outright.

**The Duke Energy Registrants are subject to numerous environmental laws and regulations requiring significant capital expenditures that can increase the cost of operations, and which may impact or limit business plans, or cause exposure to environmental liabilities.**

The Duke Energy Registrants are subject to numerous environmental laws and regulations affecting many aspects of their present and future operations, including CCRs, air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require the Duke Energy Registrants to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps the Duke Energy Registrants could be required to take to ensure their facilities are in compliance could be prohibitively expensive. As a result, the Duke Energy Registrants may be required to shut down or alter the operation of their facilities, which may cause the Duke Energy Registrants to incur losses. Further, the Duke Energy Registrants may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and their contracts with customers. Also, the Duke Energy Registrants may not be able to obtain or maintain from time to time all required environmental regulatory approvals for their operating assets or development projects. Delays in obtaining any required environmental regulatory approvals, failure to obtain and comply with them or changes in environmental laws or regulations to more stringent compliance levels could result in additional costs of operation for existing facilities or development of new facilities being prevented, delayed or subject to additional costs. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the Duke Energy Registrants' results of operations, financial position and cash flows due to regulatory cost recovery, the Duke Energy Registrants are at risk that the costs of complying with environmental regulations in the future will have such an effect.

The EPA has enacted or proposed federal regulations governing the management of cooling water intake structures, wastewater and CO2 emissions. New state legislation could impose carbon reduction goals that are more aggressive than the company's plans. These regulations may require the Duke Energy Registrants to make additional capital expenditures and increase operating and maintenance costs.

**The Duke Energy Registrants' operations, capital expenditures and financial results may be affected by regulatory changes related to the impacts of global climate change.**

There is continued concern, and increasing activism, both nationally and internationally, about climate change. The EPA and state regulators have, and may adopt and implement, additional regulations to restrict emissions of GHGs to address global climate change. Certain local and state jurisdictions have also enacted laws to restrict or prevent new natural gas infrastructure. Increased regulation of GHG emissions could impose significant additional costs on the Duke Energy Registrants' electric and natural gas operations, their suppliers and customers and affect demand for energy conservation and renewable products, which could impact both our electric and natural gas businesses. Regulatory changes could also result in generation facilities to be retired earlier than planned to meet our net-zero 2050 goal. Though we would plan to seek cost recovery for investments related to GHG emissions reductions through regulatory rate structures, changes in the regulatory climate could result in the delay in or failure to fully recover such costs and investment in generation.

**OPERATIONAL RISKS**

**The Duke Energy Registrants' results of operations may be negatively affected by overall market, economic and other conditions that are beyond their control.**

Sustained downturns or sluggishness in the economy generally affect the markets in which the Duke Energy Registrants operate and negatively influence operations. Declines in demand for electricity or natural gas as a result of economic downturns in the Duke Energy Registrants' regulated service territories will reduce overall sales and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and the use of natural gas. Although the Duke Energy Registrants' regulated electric and natural gas businesses are subject to regulated allowable rates of return and recovery of certain costs, such as fuel and purchased natural gas costs, under periodic adjustment clauses, overall declines in electricity or natural gas sold as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations.

A continuation of adverse economic conditions including economic downturn or high commodity prices could also negatively impact the financial stability of certain of our customers and result in their inability to pay for electric and natural gas services. This could lead to increased bad debt expense and higher allowance for doubtful account reserves for the Duke Energy Registrants and result in delayed or unrecovered operating costs and lower financial results. Additionally, prolonged economic downturns that negatively impact the Duke Energy Registrants' results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets, including goodwill, to their respective fair values. The Duke Energy Registrants also monitor the impacts of inflation on the procurement of goods and services and seek to minimize its effects in future periods through pricing strategies, productivity improvements, and cost reductions. Rapidly rising prices as a result of inflation or other factors may impact the ability of the company to recover costs timely or execute on its business strategy including the achievement of growth objectives.

The Duke Energy Registrants sell electricity into the spot market or other competitive power markets on a contractual basis. With respect to such transactions, the Duke Energy Registrants are not guaranteed any rate of return on their capital investments through mandated rates, and revenues and results of operations are likely to depend, in large part, upon prevailing market prices. These market prices may fluctuate substantially over relatively short periods of time and could negatively impact the company's ability to accurately forecast the financial impact or reduce the Duke Energy Registrants' revenues and margins, thereby diminishing results of operations.

Factors that could impact sales volumes, generation of electricity and market prices at which the Duke Energy Registrants are able to sell electricity and natural gas are as follows:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy or natural gas usage for heating or cooling purposes, as applicable, and periods of low rainfall that decrease the ability to operate facilities in an economical manner;
- supply of and demand for energy commodities;
- transmission or transportation constraints or inefficiencies that impact nonregulated energy operations;
- availability of purchased power;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or natural gas plants, and customer usage of energy-efficient equipment that reduces energy demand;
- natural gas, crude oil and refined products production levels and prices;
- ability to procure satisfactory levels of inventory, including materials, supplies, and fuel such as coal, natural gas and uranium; and
- capacity and transmission service into, or out of, the Duke Energy Registrants' markets.

**Natural disasters or operational accidents may adversely affect the Duke Energy Registrants' operating results.**

Natural disasters or operational accidents within the company or industry (such as forest fires, earthquakes, hurricanes or natural gas transmission pipeline explosions) could have direct or indirect impacts to the Duke Energy Registrants or to key contractors and suppliers. Further, the generation of electricity and the transportation and storage of natural gas involve inherent operating risks that may result in accidents involving serious injury or loss of life, environmental damage or property damage. Such events could impact the Duke Energy Registrants through changes to policies, laws and regulations whose compliance costs have a significant impact on the Duke Energy Registrants' results of operations, financial position and cash flows. In addition, if a serious operational accident were to occur, existing insurance policies may not cover all of the potential exposures or the actual amount of loss incurred, including potential litigation awards. Any losses not covered by insurance, or any increases in the cost of applicable insurance as a result of such accident, could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants.

**The reputation and financial condition of the Duke Energy Registrants could be negatively impacted due to their obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, remediation, disposal and monitoring relating to CCR, the high costs and new rate impacts associated with implementing these new CCR-related requirements and the strategies and methods necessary to implement these requirements in compliance with these legal obligations.**

As a result of electricity produced for decades at coal-fired power plants, the Duke Energy Registrants manage large amounts of CCR that are primarily stored in dry storage within landfills or combined with water in surface impoundments, all in compliance with applicable regulatory requirements. A CCR- related operational incident could have a material adverse impact on the reputation and results of operations, financial position and cash flows of the Duke Energy Registrants.

During 2015, EPA regulations were enacted related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the RCRA and apply to electric generating sites with new and existing landfills and, new and existing surface impoundments, and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future, such as the settlement reached with the NCDEQ to excavate seven of the nine remaining coal ash basins in North Carolina, and partially excavate the remaining two, and the EPA's January 11, 2022, issuance of a letter interpreting the CCR Rule, including its applicability and closure provisions. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, including increased operating and maintenance costs, which could affect the results of operations, financial position and cash flows of the Duke Energy Registrants. The Duke Energy Registrants will continue to seek full cost recovery for expenditures through the normal ratemaking process with state and federal utility commissions, who permit recovery in rates of necessary and prudently incurred costs associated with the Duke Energy Registrants' regulated operations, and through other wholesale contracts with terms that contemplate recovery of such costs, although there is no guarantee of full cost recovery. In addition, the timing for and amount of recovery of such costs could have a material adverse impact on Duke Energy's cash flows.

The Duke Energy Registrants have recognized significant AROs related to these CCR-related requirements. Closure activities began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to off-site locations for use as structural fill, to appropriately engineered off-site or on-site lined landfills or conversion of the ash for beneficial use. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than estimates and could, therefore, materially increase compliance expenditures and rate impacts.

**The Duke Energy Registrants' results of operations, financial position and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand or number of customers.**

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and natural gas and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by several factors outside the control of the Duke Energy Registrants, such as mandated EE measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as inflation and interest rate volatility, population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

In addition, certain regulatory and legislative bodies have passed legislation implementing the extension of certain tax credits to be used toward the costs of residential solar installation or have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates in response to concerns related to climate change. Additionally, technological advances driven by federal laws mandating new levels of EE in end-use electric and natural gas devices or other improvements in or applications of technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production utilized by the Duke Energy Registrants. In addition, the electrification of buildings and appliances currently relying on natural gas could reduce the number of customers in our natural gas distribution business.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or number of customers and may cause the failure of the Duke Energy Registrants to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on their results of operations, financial position and cash flows.

Furthermore, the Duke Energy Registrants currently have EE riders in place to recover the cost of EE programs in North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. Should the Duke Energy Registrants be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact.

**The Duke Energy Registrants future results of operations may be impacted by changing expectations and demands including heightened emphasis on environmental, social and governance concerns.**

Duke Energy's ability to execute its strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and stakeholders. Those expectations are based in part on the core fundamentals of reliability and affordability but are also increasingly focused on our ability to meet rapidly changing demands for new and varied products, services and offerings. Additionally, the risks of global climate change continues to shape our customers' sustainability goals and energy needs as well as the investment and financing criteria of investors. Failure to meet these increasing expectations or to adequately address the risks and external pressures from regulators, customers, investors and other stakeholders may impact Duke Energy's reputation and affect its ability to achieve favorable outcomes in future rate cases and the results of operations for the Duke Energy Registrants. Furthermore, the increasing use of social media may accelerate and increase the potential scope of negative publicity we might receive and could increase the negative impact on our reputation, business, results of operations, and financial condition.

As it relates to electric generation, a diversified fleet with increasingly clean generation resources may facilitate more efficient financing and lower costs. Conversely, jurisdictions utilizing more carbon-intensive generation such as coal may experience difficulty attracting certain investors and obtaining the most economical financing terms available. Furthermore, with this heightened emphasis on environmental, social, and governance concerns, and climate change in particular, there is an increased risk of litigation, activism, and legislation from groups both in support of and opposed to various environmental, social and governance initiatives, which could cause delays and increase the costs of our clean energy transition.

**The Duke Energy Registrants' operating results may fluctuate on a seasonal and quarterly basis and can be negatively affected by changes in weather conditions and severe weather, including extreme weather conditions and changes in weather patterns from climate change.**

Electric power generation and natural gas distribution are generally seasonal businesses. In most parts of the U.S., the demand for power peaks during the warmer summer months, with market prices also typically peaking at that time. In other areas, demand for power peaks during the winter. Demand for natural gas peaks during the winter months. Further, changing frequency or magnitude of extreme weather conditions such as hurricanes, droughts, heat waves, winter storms and severe weather, including from climate change, could cause these seasonal fluctuations to be more pronounced. As a result, the overall operating results of the Duke Energy Registrants' businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period-to-period comparison less relevant.

Sustained severe drought conditions could impact generation by hydroelectric plants, as well as fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, flooding, tornadoes, severe thunderstorms, snow and ice storms, including from climate change, can result in lost operating revenues due to outages, property damage, including downed transmission and distribution lines, and additional and unexpected expenses to mitigate storm damage. The cost of storm restoration efforts may not be fully recoverable through the regulatory process.

**The Duke Energy Registrants' sales may decrease if they are unable to gain adequate, reliable and affordable access to transmission assets.**

The Duke Energy Registrants depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver electricity sold to the wholesale market. In addition, the growth of renewables and energy storage will put strains on existing transmission assets and require transmission and distribution upgrades. The FERC's power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, the Duke Energy Registrants' ability to sell and deliver products may be hindered.
The different regional power markets have changing regulatory structures, which could affect growth and performance in these regions. In addition, the ISOs who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of the Duke Energy Registrants' wholesale power marketing business.

**The availability of adequate interstate pipeline transportation capacity and natural gas supply may decrease.**

The Duke Energy Registrants purchase almost all of their natural gas supply from interstate sources that must be transported to the applicable service territories. Interstate pipeline companies transport the natural gas to the Duke Energy Registrants' systems under firm service agreements that are designed to meet the requirements of their core markets. A significant disruption to interstate pipelines capacity or reduction in natural gas supply due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyberattacks or other acts of war or legislative or regulatory actions or requirements, including remediation related to integrity inspections or regulations and laws enacted to address climate change, could reduce the normal interstate supply of natural gas and thereby reduce earnings. Moreover, if additional natural gas infrastructure, including, but not limited to, exploration and drilling rigs and platforms, processing and gathering systems, offshore pipelines, interstate pipelines and storage, cannot be built at a pace that meets demand, then growth opportunities could be limited.

**Fluctuations in commodity prices or availability may adversely affect various aspects of the Duke Energy Registrants' operations as well as their results of operations, financial position and cash flows.**

The Duke Energy Registrants are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, nuclear fuel, electricity and other energy-related commodities as a result of their ownership of energy-related assets. Fuel costs are recovered primarily through cost recovery clauses, subject to the approval of state utility commissions.

Additionally, the Duke Energy Registrants are exposed to risk that counterparties will not be able to fulfill their obligations. Disruption in the delivery of fuel, including disruptions as a result of, among other things, bankruptcies, transportation delays, weather, labor relations, force majeure events or environmental regulations affecting any of these fuel suppliers, could limit the Duke Energy Registrants' ability to operate their facilities. Should counterparties fail to perform, the Duke Energy Registrants might be forced to replace the underlying commitment at prevailing market prices possibly resulting in losses in addition to the amounts, if any, already paid to the counterparties.

Certain of the Duke Energy Registrants' hedge agreements may result in the receipt of, or posting of, collateral with counterparties, depending on the daily market-based calculation of financial exposure of the derivative positions. Fluctuations in commodity prices that lead to the return of collateral received and/or the posting of collateral with counterparties could negatively impact liquidity. Downgrades in the Duke Energy Registrants' credit ratings could lead to additional collateral posting requirements. The Duke Energy Registrants continually monitor derivative positions in relation to market price activity.

**Cyberattacks and data security breaches could adversely affect the Duke Energy Registrants' businesses.**

Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyberattacks and data security breaches. Duke Energy relies on the continued operation of sophisticated digital information technology systems and network infrastructure, which are part of an interconnected regional grid. Additionally, connectivity to the internet continues to increase through grid modernization and other operational excellence initiatives. Because of the critical nature of the infrastructure, increased connectivity to the internet and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism or other types of data security breaches, the Duke Energy Registrants face a heightened risk of cyberattack from foreign or domestic sources and have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to information and/or information systems or to disrupt utility operations through computer viruses and phishing attempts either directly or indirectly through its material vendors or related third parties. In the event of a significant cybersecurity breach on either the Duke Energy Registrants or with one of our material vendors or related third parties, the Duke Energy Registrants could (i) have business operations disrupted, including the disruption of the operation of our natural gas and electric assets and the power grid, theft of confidential company, employee, retiree, shareholder, vendor or customer information, and general business systems and process interruption or compromise, including preventing the Duke Energy Registrants from servicing customers, collecting revenues or the recording, processing and/or reporting financial information correctly, (ii) experience substantial loss of revenues, repair and restoration costs, penalties and costs for lack of compliance with relevant regulations, implementation costs for additional security measures to avert future cyberattacks and other financial loss and (iii) be subject to increased regulation, litigation and reputational damage. While Duke Energy maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures.

The Duke Energy Registrants are subject to standards enacted by the North American Electric Reliability Corporation and enforced by FERC regarding protection of the physical and cybersecurity of critical infrastructure assets required for operating North America's bulk electric system. The Duke Energy Registrants are also subject to regulations set by the Nuclear Regulatory Commission regarding the protection of digital computer and communication systems and networks required for the operation of nuclear power plants. The Duke Energy Registrants that operate designated critical pipelines that transport natural gas are also subject to security directives issued by the Department of Homeland Security's Transportation Security Administration (TSA) requiring such registrants to implement specific cybersecurity mitigation measures. While the Duke Energy Registrants believe they are in compliance with, or, in the case of recent TSA security directives, are in the process of implementing such standards and regulations, the Duke Energy Registrants have from time to time been, and may in the future be, found to be in violation of such standards and regulations. In addition, compliance with or changes in the applicable standards and regulations may subject the Duke Energy Registrants to higher operating costs and/or increased capital expenditures as well as substantial fines for non-compliance.

**The Duke Energy Registrants' operations have been and may be affected by pandemic health events, including COVID-19, in ways listed below and in ways the Duke Energy Registrants cannot predict at this time.**

The COVID-19 pandemic and efforts to respond to it have resulted in widespread adverse consequences on the global economy and on the Duke Energy Registrants' customers, third-party vendors, and other parties with whom we do business. If the COVID-19 pandemic or other health epidemics and outbreaks that may occur are significantly prolonged, it could impact the Duke Energy Registrants' business strategy, results of operations, financial position and cash flows in the future as a result of delays in rate cases or other legal proceedings, an inability to obtain labor or equipment necessary for the construction of large capital projects, an inability to procure satisfactory levels of fuels or other necessary equipment for the continued production of electricity and delivery of natural gas, and the health and availability of our critical personnel and their ability to perform business functions.

**Duke Energy Ohio's and Duke Energy Indiana's membership in an RTO presents risks that could have a material adverse effect on their results of operations, financial position and cash flows.**

The rules governing the various regional power markets may change, which could affect Duke Energy Ohio's and Duke Energy Indiana's costs and/or revenues. To the degree Duke Energy Ohio and Duke Energy Indiana incur significant additional fees and increased costs to participate in an RTO, their results of operations may be impacted. Duke Energy Ohio and Duke Energy Indiana may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Duke Energy Ohio and Duke Energy Indiana may be required to expand their transmission system according to decisions made by an RTO rather than their own internal planning process. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on the results of operations, financial position and cash flows of Duke Energy Ohio and Duke Energy Indiana.

As members of an RTO, Duke Energy Ohio and Duke Energy Indiana are subject to certain additional risks, including those associated with the allocation among RTO members, of losses caused by unreimbursed defaults of other participants in the RTO markets and those associated with complaint cases filed against an RTO that may seek refunds of revenues previously earned by RTO members.

**The Duke Energy Registrants may not recover costs incurred to begin construction on projects that are canceled.**

Duke Energy's long-term strategy requires the construction of new projects, either wholly owned or partially owned, which involve a number of risks, including construction delays, delays in or failure to receive required regulatory approvals and/or sitting or environmental permits, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, the Duke Energy Registrants enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled.

**The Duke Energy Registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.**

The financial condition of some insurance companies, actual or threatened physical or cyberattacks, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the Duke Energy Registrants and their respective competitors typically insure against may decrease, and the insurance that the Duke Energy Registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred. Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, financial position or cash flows of the affected Duke Energy Registrant.

**Our business could be negatively affected as a result of actions of activist shareholders.**

While we strive to maintain constructive communications with our shareholders, activist shareholders may, from time to time, engage in proxy solicitations or advance shareholder proposals, or otherwise attempt to affect changes and assert influence on our Board and management. Perceived uncertainties as to the future direction or governance of the company may cause concern to our current or potential regulators, vendors or strategic partners, or make it more difficult to execute on our strategy or to attract and retain qualified personnel, which may have a material impact on our business and operating results.

In addition, actions such as those described above could cause fluctuations in the trading price of our common stock, based on temporary or speculative market perceptions or other factors that do not necessarily reflect the underlying fundamentals and prospects of our business.

## NUCLEAR GENERATION RISKS

**Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida may incur substantial costs and liabilities due to their ownership and operation of nuclear generating facilities.**

Ownership interests in and operation of nuclear stations by Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida subject them to various risks. These risks include, among other things: the potential harmful effects on the environment and human health resulting from the current or past operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

Ownership and operation of nuclear generation facilities requires compliance with licensing and safety-related requirements imposed by the NRC. In the event of non-compliance, the NRC may increase regulatory oversight, impose fines or shut down a unit depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside of the control of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, such as a serious nuclear incident at a facility owned by a third party, could necessitate substantial capital and other expenditures, as well as assessments to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants.

## LIQUIDITY, CAPITAL REQUIREMENTS AND COMMON STOCK RISKS

**The Duke Energy Registrants rely on access to short-term borrowings and longer-term debt and equity markets to finance their capital requirements and support their liquidity needs. Access to those markets can be adversely affected by a number of conditions, many of which are beyond the Duke Energy Registrants' control.**

The Duke Energy Registrants' businesses are significantly financed through issuances of debt and equity. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from their assets. Accordingly, as a source of liquidity for capital requirements not satisfied by the cash flows from their operations and to fund investments originally financed through debt instruments with disparate maturities, the Duke Energy Registrants rely on access to short-term money markets as well as longer-term capital markets. The Subsidiary Registrants also rely on access to short-term intercompany borrowings. If the Duke Energy Registrants are not able to access debt or equity at competitive rates or at all, the ability to finance their operations and implement their strategy and business plan as scheduled could be adversely affected. An inability to access debt and equity may limit the Duke Energy Registrants' ability to pursue improvements or acquisitions that they may otherwise rely on for future growth.

Market disruptions may increase the cost of borrowing or adversely affect the ability to access one or more financial markets. Such disruptions could include: economic downturns, unfavorable capital market conditions, market prices for natural gas and coal, geopolitical risks, actual or threatened terrorist attacks, or the overall health of the energy industry. Additionally, rapidly rising interest rates could impact the ability to affordably finance the capital plan or increase rates to customers and could have an impact on our ability to execute on our clean energy transition. The availability of credit under Duke Energy's Master Credit Facility depends upon the ability of the banks providing commitments under the facility to provide funds when their obligations to do so arise. Systemic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the facility agreement.

Duke Energy maintains a revolving credit facility to provide backup for its commercial paper program and letters of credit to support variable rate demand tax- exempt bonds that may be put to the Duke Energy Registrant issuer at the option of the holder. The facility includes borrowing sublimits for the Duke Energy Registrants, each of whom is a party to the credit facility, and financial covenants that limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude Duke Energy from issuing commercial paper or the Duke Energy Registrants from issuing letters of credit or borrowing under the Master Credit Facility.

**The Duke Energy Registrants must meet credit quality standards and there is no assurance they will maintain investment grade credit ratings. If the Duke Energy Registrants are unable to maintain investment grade credit ratings, they would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect their liquidity.**

Each of the Duke Energy Registrants' senior long-term debt issuances is currently rated investment grade by various rating agencies. The Duke Energy Registrants cannot ensure their senior long-term debt will be rated investment grade in the future.

If the rating agencies were to rate the Duke Energy Registrants below investment grade, borrowing costs would increase, perhaps significantly. In addition, the potential pool of investors and funding sources would likely decrease. Further, if the short-term debt rating were to fall, access to the commercial paper market could be significantly limited.

A downgrade below investment grade could also require the posting of additional collateral in the form of letters of credit or cash under various credit, commodity and capacity agreements and trigger termination clauses in some interest rate derivative agreements, which would require cash payments. All of these events would likely reduce the Duke Energy Registrants' liquidity and profitability and could have a material effect on their results of operations, financial position and cash flows.

**Non-compliance with debt covenants or conditions could adversely affect the Duke Energy Registrants' ability to execute future borrowings.**

The Duke Energy Registrants' debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements.

**Market performance and other changes may decrease the value of the NDTF investments of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, which then could require significant additional funding.**

Ownership and operation of nuclear generation facilities also requires the maintenance of funded trusts that are intended to pay for the decommissioning costs of the respective nuclear power plants. The performance of the capital markets affects the values of the assets held in trust to satisfy these future obligations. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida have significant obligations in this area and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected rates of return. Although a number of factors impact funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning nuclear plants. If Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are unable to successfully manage their NDTF assets, their results of operations, financial position and cash flows could be negatively affected.

**Poor investment performance of the Duke Energy pension plan holdings and other factors impacting pension plan costs could unfavorably impact the Duke Energy Registrants' liquidity and results of operations.**

The costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and required or voluntary contributions made to the plans. The Subsidiary Registrants are allocated their proportionate share of the cost and obligations related to these plans. Without sustained growth in the pension investments over time to increase the value of plan assets and, depending upon the other factors impacting costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations, and the Subsidiary Registrants' proportionate share of such cash funding obligations, could have a material adverse impact on the Duke Energy Registrants' results of operations, financial position and cash flows.

**Duke Energy is a holding company and depends on the cash flows from its subsidiaries to meet its financial obligations.**

Because Duke Energy is a holding company with no operations or cash flows of its own, its ability to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on its common stock, is primarily dependent on the net income and cash flows of its subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Duke Energy, its subsidiaries have regulatory restrictions and financial obligations that must be satisfied. These subsidiaries are separate legal entities and have no obligation to provide Duke Energy with funds. In addition, Duke Energy may provide capital contributions or debt financing to its subsidiaries under certain circumstances, which would reduce the funds available to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on Duke Energy's common stock.

**GENERAL RISKS**

**The failure of Duke Energy information technology systems, or the failure to enhance existing information technology systems and implement new technology, could adversely affect the Duke Energy Registrants' businesses.**

Duke Energy's operations are dependent upon the proper functioning of its internal systems, including the information technology systems that support our underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of our operations. In the ordinary course of business, we rely on information technology systems, including the internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) proprietary business information, (iii) personally identifiable information of our customers, employees, retirees and shareholders and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. Our information technology systems are dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers' systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, break-ins and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially affect the results of operations, financial position and cash flows of the Duke Energy Registrants.

In addition to maintaining our current information technology systems, Duke Energy believes the digital transformation of its business is key to driving internal efficiencies as well as providing additional capabilities to customers. Duke Energy's information technology systems are critical to cost-effective, reliable daily operations and our ability to effectively serve our customers. We expect our customers to continue to demand more sophisticated technology-driven solutions and we must enhance or replace our information technology systems in response. This involves significant development and implementation costs to keep pace with changing technologies and customer demand. If we fail to successfully implement critical technology, or if it does not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect our business strategy as well as impact the results of operations, financial position and cash flows of the Duke Energy Registrants.

**Potential terrorist activities, or military or other actions, could adversely affect the Duke Energy Registrants' businesses.**

The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil, which may have material adverse effects in ways the Duke Energy Registrants cannot predict at this time. In addition, future acts of terrorism and possible reprisals as a consequence of action by the U.S. and its allies could be directed against companies operating in the U.S. Information technology systems, transportation systems for our fuel sources including natural gas pipelines, transmission and distribution and generation facilities such as nuclear plants could be potential targets of terrorist activities or harmful activities by individuals or groups that could have a material adverse effect on Duke Energy Registrants' businesses. In particular, the Duke Energy Registrants may experience increased capital and operating costs to implement increased security for their information technology systems, transmission and distribution and generation facilities, including nuclear power plants under the NRC's design basis threat requirements. These increased costs could include additional physical plant security and security personnel or additional capability following a terrorist incident.

**Failure to attract and retain an appropriately qualified workforce could unfavorably impact the Duke Energy Registrants' results of operations.**

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may increase. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the business, especially considering the workforce needs associated with nuclear generation facilities and new skills required to operate a modernized, technology-enabled power grid. If the Duke Energy Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations, financial position and cash flows could be negatively affected.

Coyne orally testified that: "We also have Eversource in there, for example that's just a pure transmission and distribution utility." While it is a holding company with operating subsidiaries that distribute natural gas, electricity and water, in 2022 Eversource Energy also owned an "offshore wind business, which includes a 50 percent ownership interest in offshore wind projects that are being developed and constructed through a joint and equal partnership with Ørsted." An excerpt from Eversource Energy's 2022 10-K reads:

Eversource's offshore wind business includes a 50 percent ownership interest in North East Offshore, which holds power purchase agreements (PPAs) and contracts for the Revolution Wind, South Fork Wind and Sunrise Wind projects, as well as an undeveloped offshore lease area. Our offshore wind projects are being developed and constructed through a joint and equal partnership with Ørsted.

The offshore leases include a 257 square-mile ocean lease off the coasts of Massachusetts and Rhode Island and a separate, adjacent 300 square- mile ocean lease located approximately 25 miles south of the coast of Massachusetts. In aggregate, these ocean lease sites jointly-owned by Eversource and Ørsted could eventually develop at least 4,000 MW of clean, renewable offshore wind energy.

Revolution Wind is a 704 MW offshore wind power project located approximately 15 miles south of the Rhode Island coast, and South Fork Wind is a 130 MW offshore wind power project located approximately 35 miles east of Long Island. Sunrise Wind is a 924 MW offshore wind facility, which will be developed 35 miles east of Montauk Point, Long Island. The completion dates for these projects are subject to federal permitting through BOEM, engineering, state siting and permitting in New York, Rhode Island and Massachusetts and construction schedules. We have initiated a strategic review of our offshore wind investment portfolio. As part of that review, we are exploring strategic alternatives that could result in a potential sale of all, or part, of our 50 percent interest in our offshore wind partnership with Ørsted...