<u>M12282- Evidence of P. Bowman, on behalf of IG</u>

The previously submitted Evidence of P. Bowman, on behalf of IG has been withdrawn and replaced with exhibit E-14.

PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO EFFICIENCY ONE ("E1")
BENEFIT-COST ANALYSIS TEST ("BCA")

Submitted to:

The Nova Scotia Energy Board

on behalf of

The Industrial Group

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INTRODUCTION

This Pre-filed Testimony has been prepared by Mr. Patrick Bowman of Bowman Economic Consulting Inc., retained by the Industrial Group ("IG") of Nova Scotia. This testimony reviews and assesses the 2025 EfficiencyOne ("E1") Application ("Application") to implement a New Benefit-Cost Analysis Test ("BCA") for Evaluating Demand Side Management ("DSM") Plans. The Application was filed with the Nova Scotia Energy Board ("Board") on May 16, 2025.

With respect to the testimony contained herein, Mr. Bowman notes the following:

- Mr. Bowman is an independent witness, and his Resume is provided in Appendix A.
- Mr. Bowman's scope on this assignment was to review and assess the Application taking into account relevant regulatory principles for electric utilities and DSM delivery utilities.
- Mr. Bowman acknowledges his role is to provide opinion evidence to the Board that is fair, objective and non-partisan.
- Mr. Bowman has endeavoured to ensure all factual assumptions and specific information relied upon are expressly cited in the testimony that follows.

This is the first E1 proceeding in which Mr. Bowman has participated.

As set out in Appendix A, Mr. Bowman has been involved in electric utility regulation, planning, energy efficiency and cost allocation matters since 1998, and has prepared expert evidence and testified on the subjects on multiple occasions across most jurisdictions in Canada. Mr. Bowman's regulatory and rate-setting experience includes work for each of utilities, large industrial customers, small commercial and residential customers, wholesale customers, and regulators. Mr. Bowman holds a Masters degree in Natural Resource Management, focused on areas of natural resource and environmental economics, and served as scholar for the International Institute for Sustainable Development ("IISD") during completion of graduate work.

TERMINOLOGY

In assessing DSM (both energy efficiency and strategic electrification), it is necessary to assess cost-effectiveness, and to utilize a metric to compare benefits and costs. Broadly, this process is termed **Benefit-Cost Analysis or BCA**, and defines a process of calculation of comparison metrics. There are multiple potential BCA perspectives, which leads to different sets of inputs being included in the BCA – for example, participant-related inputs, utility-related inputs, customer-related inputs, or societal-related inputs, and various combinations thereof. An example of a BCA perspective is the Total Resource Cost ("TRC").

One or more BCA perspectives can be considered by a jurisdiction to determine which DSM to pursue – broadly termed a "test". The selection of one or more BCA perspectives by an individual regulator is known as a **Jurisdiction-Specific Test ("JST")**.

E1 has proposed a Nova Scotia-specific JST, which is a BCA that includes specific fixed items in each of the Benefits portion of the inputs, and the Costs portion of the inputs. In this submission, the E1 proposal is termed the **"Proposed BCA"**. Because the E1 Proposed BCA does not precisely accord with any single traditional BCA, it is best termed simply the Proposed BCA. For comparison to other jurisdictions, the Proposed BCA is most similar to the Societal Cost Test, or "SCT".

The inputs to any BCA can operate a various levels of granularity, which are known as DSM **Measures** or **Activities** at a more granular level, which are consolidated into **Programs** at a somewhat less granular level, and ultimately the least granular or most consolidated level, known as a **Plan** or **Portfolio.**

BACKGROUND AND CONTEXT

This evidence relies on the following context for E1, and the broad understanding of the regulation of E1 and the role of the Board.

E1 is the current franchise holder for development and delivery of DSM plans and programs in Nova Scotia. The DSM activities of E1 must be approved by the Board, as outlined in the *Public Utilities Act* s.79A to s.79W, and in particular s.79G, s.79H, s.79I, s.79L, and s.79M.

The *Act* is based around two overlapping concepts. First, a DSM *operation* comprised of "activities, programs or plans"[1] per the definition of DSM. Second, a DSM *purchase agreement* between the franchise holder and Nova Scotia Power Inc ("NSPI"). Though the concepts are different (one relates to a set of actions, while the second relates to a contractual agreement to undertake the actions), the *Act* appears to treat the two in an analogous manner in the context of needing Board approval, in response to an application by E1.[2]

The framework for review of E1's proposals are rooted in the fact that E1 has the exclusive right to provide NSPI with "reasonably available, cost-effective"[3] DSM. The Act does not appear to require nor contemplate a concept of pursuing all cost-effective DSM – cost-effectiveness is only considered in the context of the complementary concept that the DSM should also be reasonably available. There does not appear to be any guidance in the legislation regarding tests for reasonable availability.

[1] Public Utilities Act, s.79A(b).
[2] Specifically, the Board must determine the DSM actions to be undertaken, per s.79H(1), but must also must review the agreement, per s.79L.
[3] Public Utilities Act. s.79C(2)(a).

Given the current Application contemplates establishing a test that would be applied by the Board in future proceedings, it is necessary to consider the context for the Board conducting a review. The role of the Board in respect of DSM contains multiple provisions:

- s.79G(1) – Board has general supervision powers and access to all relevant information to conduct duties.
- s.79G(2) – All relevant sections of the Act apply to E1 as a public utility.
- s.79H(1) - the Board shall determine the cost-effective DSM that must be undertaken.
- s.79H(2) - the Board shall evaluate the proposed cost-effective demand-side management at the portfolio level (the aggregate of DSM programs).
- s.79I(2) – the Board shall establish the terms and conditions of the DSM agreement between E1 and NSPI, which must (among other things) establish the DSM that E1 will provide to NSPI. The DSM should be reasonably available and oriented towards reducing costs for customers (s.79I(1)).
- s.79L(4) – the Board shall approve an Application by E1 if (i) it is in the best interests of NSPI customers, and (ii) it satisfies any other matter the Board considers appropriate.
- s.79L(5) – the Board's review must consider any matters deemed appropriate by the Board.

The combination of the above factors provides a framework for Board review, including the following considerations:

1) **Board must address DSM at multiple granularity levels:** The Board's role is to determine the cost-effective DSM that must be undertaken. In this context, the Board is not just assessing the broad reasonableness of E1 plans or targets or spending – it must make a determination of the DSM to be pursued, with DSM defined as not just a Plan or Portfolio, but also Programs and Activities. Further, in making its finding, the Board is prescribing what DSM must occur, not just a general outline of activities and programs that are broadly consistent with a Plan or Portfolio.
2) **Board must assess cost-effectiveness at the Portfolio level:** Notwithstanding that it is engaged in determining the actual DSM activities and programs to be pursued, among the duties assigned to the Board is to assess cost-effectiveness at the Portfolio level. The Board does not appear to be prohibited from also assessing cost-effectiveness at other more granular levels (such as the program or measure level).
3) **Board must ensure DSM is in the best interests of NSPI customers:** While the Board can take any matters it determines are appropriate into account, one matter it must take into account is whether the DSM is in the best interests of NSPI customers. In order to approve the Application, it must be in the best interest of customers. It is assumed that this analysis must be applied to

customers *qua* customer interests (e.g., price, reliability, availability, etc.) which appears to be consistent with the Board's earlier determinations as well.[4] This does not appear to prohibit the Board taking into account any number of other factors in determining what DSM activities and programs are to be pursued, including being cost-effective and reasonably available, but the best interests of NSPI customers must be one factor that is satisfied.

Outside of the *Public Utilities Act* itself, the review of matters by the Board appears to also be governed by the *Energy and Regulatory Boards Act*, including provision 6(2) which notes:

> 6(2) In approving or fixing rates, tolls, charges, tariffs, capital applications and all other matters over which the Energy Board has authority, the Board shall give appropriate consideration to the extent to which such rates, tolls, charges, tariffs, capital applications or other matters
>
> (a) support competition and innovation in the provision of energy resources in the Province;
>
> (b) support the development of a competitive electricity market;
>
> (c) ensure the provision of safe, secure, reliable and economical energy supply in the Province;
>
> (d) support sustainable development and sustainable prosperity; and
>
> (e) support such other factors as prescribed by the regulations,
>
> with the goal of approving rates, tolls, charges, tariffs, capital applications or other matters that are consistent with the purpose of this Act, the More Access to Energy Act and the regulations.

Sustainable Development and Sustainable Prosperity are formally defined in the *Environment Act*, and the *Environmental Goals and Sustainable Prosperity Act*, respectively, and appear to broadly accord with the typical definitions and principles applied to these terms, such as from the United Nations or IISD.

[4] 2020 NSUARB 56, M08888.

E1 PROPOSAL

E1 conducted a review of possible BCA tests. What was the objective of this review?

As per E1's submission to the Board in M10473 (the E1 2022-2025 DSM Resource Plan proceeding), E1 was directed to conduct a "thorough assessment of the relative merits of both the PAC test and a jurisdiction-specific test" in order to "determine the optimal cost-effectiveness testing methodology for Nova Scotia."[5]

What is E1 proposing as a BCA?

E1 has proposed that its current reliance on the Total Resource Cost ("TRC") screening test for cost-effectiveness (and to a lesser degree, the Program Administrator Cost ("PAC") test) be replaced by a new Proposed BCA specific to Nova Scotia. The Proposed BCA is much broader than the TRC test, and is akin to a test of total societal impacts:[6]

> The BCA test is aligned with Nova Scotia's policy objectives as opposed to the current TRC test, by incorporating non-utility impacts, including other fuel, host customer benefits, and societal impacts into the benefit-cost analysis.

E1 has also sought approval that the Proposed BCA cost-effectiveness test be applied only at the Portfolio level, to determine if the Plan/Portfolio is in the public interest.

Are there other items which E1 indicates it is seeking the Board to issue direction or some form of affirmation in this proceeding?

Yes.

E1 has indicated that it is specifically seeking approval of (i) a 2% discount rate to quantify societal impacts, and (ii) the host customer non-energy benefits to be quantified using proxy adders applied as a percentage of net energy benefits or of measure costs, subject to updates from a proposed evergreen process.[7]

Outside of these specific items, is E1 seeking approval of, or additional endorsements from the Board?

E1 indicates that in future it will provide specific other data "for information purposes" which "may be used to inform, guide discussion, and support recommendations as opposed to using them as a binding

[5] 2022 NSUARB 137 M10473; paragraph 72-73.
[6] Evidence, page 2; Exhibit E-1; pdf page 13 of 450.
[7] E1 responses to IRs from IG; IR-14; Exhibit E-4, pdf page 36 of 40.

decision making tool to approve or reject the DSM Plan as is the case with the approved screening test."[8] This includes the following:

- "E1 currently provides and intends to continue to provide the results from the Program Administrator Cost (PAC) test (includes utility benefits and utility costs only) for informational purposes".[9]
- "E1 commits to continuing to provide all appropriate data relating to the application of the BCA test at the measure, program component and portfolio level in all future DSM Plan applications."[10]

It appears E1 is suggesting that by approving the Proposed BCA in this proceeding, the Board would be implicitly approving that these other information-only metrics would not be part of any binding decision-making input.

If the additional information-only components are not for binding decision-making, how are they proposed to be used?

E1 has indicated that its Portfolio will be developed based on the Proposed BCA, as well as less-definable criteria which include: "a balanced portfolio design; equitable allocation of investment and savings between residential and business sectors; and access to programs by all market sectors and rate classes by addressing barriers to participation."[11] It appears the additional information-only items (e.g., the PAC test, and the Proposed BCA at the measure or program level), will be used to help inform this portfolio development by E1.

With respect to regulatory review, E1 advocates a concept where multiple aspects of the Board's mandate may lead to discretion for the Board to consider more granular considerations than simply the Portfolio level, but that cost-effectiveness specifically can only be assessed at the Portfolio level:[12]

> The Nova Scotia Energy Board retains discretion to allow inclusion of DSM portfolio components that may not individually satisfy the BCA test. This discretion is grounded in both the Board's broader mandate to consider planning objectives, policy alignment, and the public interest, and its requirement to assess cost effectiveness at the Portfolio level rather than at the measure or program level.

[8] E1 responses to IRs from IG; IR-05(a); Exhibit E-4, pdf page 13 of 40.
[9] E1 responses to IRs from NSEB; IR-34; Exhibit E-5; pdf page 76 of 91.
[10] Evidence, page 10; Exhibit E-1; pdf page 21 of 450.
[11] E1 Evidence, page 6 of 28; Exhibit E-1, pdf page 17 of 450.
[12] E1 responses to IRs from NSEB; IR-12(b); Exhibit E-5, pdf page 32 of 91.

The above quote from E1 makes no reference to the complementary power of discretion of the Board to *disallow* any portfolio components (only to allow). The above quote also makes reference to cost-effectiveness being assessed at the Portfolio level "rather than" more granular levels, wording that is not contained in the legislation.

EVALUATION OF E1'S PROPOSED BCA

Why is E1 adopting the new Proposed BCA?

E1 indicates that the previous TRC does not show balance, in that participant costs are included in the Costs component of the BCA, but the benefits (other than energy savings) received by the participant are not included in the Benefits component of the BCA inputs.

E1 also asserts that changes in legislation appear to remove the previous limitations that led the Board to impose the version of TRC test that lacks balance.

Is the E1 commentary a fair criticism of the TRC as previously applied in Nova Scotia?

Yes, from a principled perspective. In general, BCA should include all measurable and meaningful benefits and costs at the proposed assessment scale. The existing TRC as applied in Nova Scotia does not do this.

However, the previous TRC excluded non-energy benefits because the Board had concluded in M08888 that "The Board does not have the jurisdiction to take into account non-energy impacts in cost-effectiveness testing."[13]

E1 indicates that the new *Energy and Regulatory Boards Act* now permits and/or requires the Board to give "appropriate consideration" to such non-energy matters. Whether this is a correct interpretation is a legal question that has not been adjudicated.

Regardless, there remains a technical question of how best to respond to the E1 criticism of the TRC test in the event the Board does in fact have the jurisdiction now to consider non-energy benefits. Also, if the test is being revised, it is necessary to ensure any new test or tests applied can fully meet the requirements that must be fulfilled by the Board.

Does E1 appear to accurately portray the economic and policy framework for DSM in Nova Scotia?

[13] 2020 NSUARB 56 M08888, pdf page 2 of 19.

No.

First, although the legislation indicates that cost-effectiveness shall be measured at the portfolio level, there is no prohibition against also assessing cost-effectiveness at other granularity levels, such as program or measure. Indeed, to fulfill its other mandates (i.e., to "determine the cost-effective DSM that must be undertaken"[14] with DSM defined as "activities, programs and plan"), it appears the Board must consider cost effectiveness at a more granular level than simply the portfolio level.

In order to determine that any given portfolio of DSM is (i) in the best interests of customers (s.79L(4)), (ii) is comprised of activities and programs that are reasonable available (s.79I(1)), and (iii) any other interest it considers relevant (s.79L(5)), the Board will also require information regarding alternative DSM plans, comprised of different measures and programs, at both larger and smaller scales than E1's main proposal. This information is required to permit appropriate comparison of alternatives. Such analyses cannot only be conducted solely at the Portfolio level.

Second, among other assessments it may make in determining the public interest, the Board must assess DSM from the perspective of what is in the best interests of NSPI's customers[15], and the Board must assess that the DSM is oriented towards reducing costs for customers.[16] This has previously been determined by the Board to mean customer interests in respect of their interactions with energy – i.e., price, reliability, availability.[17] There has been no change to the substantive wording of the section of the legislation where these requirements arise since the Board made this determination[18], so presumably the same tests and constraints apply. This does not mean the primary BCA test must be focused on NSPI customers, but if it is not, a secondary test would appear to also be required, which is focused on actually assessing customer interests (i.e., a test, and not simply information-only supplemental information).

E1 does not appear to address this requirement of the legislation in their proposal.

Is the Proposed E1 BCA the only possible response to the criticism?

No. From the outset, the assessment to be conducted was to consider two alternatives to the TRC – either relying primarily on PAC, or developing a new Nova Scotia specific test. As the legislation changed partway through the assessment, in a manner E1 indicates resolves the previous limit on the TRC being unbalanced, a third approach became available which is to simply adjust the TRC to achieve the more traditional balance associated with that test (i.e., to add in non-energy customer benefits).

[14] Public Utilities Act, s.79H(1).
[15] Public Utilities Act, s.79L(4).
[16] Public Utilities Act, s.79I(1).
[17] 2020 NSUARB 56 M08888, paragraph 33, pdf page 15 of 19.
[18] Public Utilities Act, s.79L(4).

To understand these options, it must be recognized that there are broadly five assessment scales that can be considered in evaluating DSM activities.

- **Utility-Specific Perspective (including the utility's customers generally).** This perspective includes primarily the costs and benefits ascribable to the utility itself, which is largely analogous with the utility's revenue requirement, and the bills paid by its customers. This is typically represented by the Utility Cost Test ("UCT") or the Program Administrator Cost Test ("PAC"). A measure, program or portfolio that passes the UCT and/or PAC typically indicates the utility's net costs, and thus its future customer charges, will likely be lower than it would be without the program.
- **Participant-Specific Perspective.** This perspective measures the economic profile of the measure or program for the participants. It includes the costs and benefits experienced by the participants (including, for example, incentives paid by E1), and indicates if the customer would be better off with the program or measure than they would be without it. This is typically represented by the Participant Cost Test ("PCT").
- **Combined Utility/Participant Perspective.** This perspective is represented by the Total Resource Cost ("TRC") test, which is in effect a sum of the PAC and the PCT. While this is a widely-used measure of DSM programs, it can be difficult to properly understand the results, as the measurements are collective but not universal. Collective, in the sense that the test does not indicate that either the utility, nor the participant, will be better off or worse off, only that the combination of the two will be better off. It is not universal in that the test does not take into account any considerations beyond the utility-participant combination (i.e., non-participant customers). The test also does not take into account any transactions between the utility and the participant, such as incentives paid, since these are a benefit to one party (the participant) and a cost to the other (the utility) so net out to zero. For this reason, a TRC cannot indicate if an appropriate incentive is being paid, versus one that may be far too high, or far too low.
- **Society Perspective.** A broader test than the TRC, the society-wide perspective is represented by the Societal Cost Test ("SCT") including all matters on the TRC plus impacts that are felt more broadly than simply the utility or its participant customers. Similar to the TRC, this test is not informative regarding many important aspects (such as incentives), but also calculates benefits that can be highly delinked from the program costs paid by utilities and their customers. For example, by using a Social Cost of Carbon estimate (as proposed by E1) the benefits of GHG

emission reductions encompass all global impacts, not just those domestic to Nova Scotia or even Canada.[19]

- **Non-Participant Customer Perspective.** For non-participants in DSM, the PAC is useful but not sufficient to indicate their interests as customers. This is because of the nature of the design of a utility's rates to recover all utility costs. For example, if a utility saves supply costs overall (say $100), leading to a lower revenue requirement (i.e., the measure passes the PAC test because of savings), but the utility load will drop such that its revenue from the participant customers has fallen by $150, the extra $50 has to be made up from other customers (i.e., non-participant customers) through higher bills. This adverse effect on other customers is not otherwise captured in DSM analysis, because none of the other tests considers the adverse effects of the lost revenue impacts of the DSM (such a result is only reported via a test, if a Rate Impact Measure ("RIM") test is applied). Rate impacts are a real and important consideration in assessing customer interests, but are of limited use as a test.

E1's criticism of the TRC, which is echoed by Synapse's findings in its review of the E1 2023-2025 DSM Plan[20], is that the TRC as applied in Nova Scotia was unbalanced, since it did not include both participant costs and participant non-energy benefits, but only the costs. However, this could be addressed in at least three different ways:

- Option 1: If the legal jurisdiction of the Board has indeed now expanded to include the ability to consider non-energy benefits, E1 could have proposed to simply retain but adjust the Nova Scotia TRC test to now include the non-energy benefits.
- Option 2: E1's proposal is the second option, which expands the primary test to include not only the non-energy benefits received by participants, but also to expand the scope to include most or all societal impacts. Among peer Canadian jurisdictions, this is the approach that only appears to have been taken by Alberta, via the Energy Efficiency Alberta office that is now closed.[21]
- Option 3: E1 could have proposed that the primary test for DSM become the PAC/UCT test, as is the case (in full or in part) in Manitoba, BC, New Brunswick, Ontario, PEI, Saskatchewan and Yukon.[22] This would have also improved the Board's ability to, in one measure, fulfill its requirements to consider the best interests of NSPI customers.[23] For beneficial electrification, the

[19] Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada, 2023; Government of Canada. Available: https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html#toc13
[20] 2022 NSUARB 137 M10473, paragraph 69.
[21] E1 responses to IRs from SBA; IR-19(a); Exhibit E-6; pdf page 29 of 34. E1 also indicates that a societal cost test is under development in New Brunswick, but not yet complete.
[22] E1 responses to IRs from SBA; IR-19(a); Exhibit E-6; pdf page 29 of 34.
[23] Public Utilities Act, s.79L(4).

assessment can include benefits to the utility in terms of added revenue, which is the fundamental benefit to the utility and its customers from added sales.

Under either of Option 1 or Option 2 above, E1 would need to continue to include proper PAC and rate impact testing in any event, to ensure the Board has addressed the specific interests of NSPI customers.

Given the range of options, has E1 proposed the most reasonable alternative for the primary BCA test?

No.

The easiest approach would be to pursue Option 1, to simply expand the TRC to include non-energy benefits, while increasing the complementary focus on the PAC and bill impact assessments to address the specific impacts on NSPI customers. However, because TRC makes no distinction between the participant customer and the utility in the benefit and cost measurement, it imposes significant limits on the decision-making framework for the Board. For example, it does not consider the impact or reasonableness of varying potential incentive levels, which is necessary to consider NSPI customer interests.

E1 has instead adopted the Proposed BCA (Option 2), which is excessively expansive as a primary test. DSM analyzed at the societal level for the purpose of regulator approvals is uncommon in Canada.

Option 3 would be preferred, as it would align E1 with most Canadian peer utilities, and would encompass both the Board's requirement that it consider NSPI customer interests in the same metric as the E1 program screening.

Why would a focus on the PAC test as the primary test be preferred to the Proposed BCA?

The Proposed BCA is fundamentally delinked from the utility and its customers, which provide the funding for the programs. For example, using the Heat Pump examples provided in E1's evidence, the Proposed BCA would be based on the following formula to derive a ratio, and tested whether it exceeds 1.0. In the following examples, the Proposed BCA is compared to a PAC test (including the revenue benefits in the case of beneficial electrification):[24]

[24] E1 response to NSEB IR-26 Attachment 1, Exhibit E-5i.

For conversion of electric resistance heating to heat pumps (energy efficiency):

Proposed BCA (societal perspective)	**PAC (utility and its customers perspective)**
Benefits = NPV of avoided electric generation and capacity costs, avoided transmission and distribution costs, beneficial health impacts from reduced electric generation, avoided GHG global social costs, and other non-energy benefits for the host customer (via proxy)	Benefits: NPV of avoided electric generation and capacity costs, avoided transmission and distribution costs
Costs = NPV of full costs to install heat pump, program administration	Costs = NPV of costs to incent customer to install heat pump, program administration

For conversion of fuel oil heating to heat pumps (beneficial electrification):

Proposed BCA (societal perspective)	**PAC (utility and its customers perspective, including revenue)**
Benefits = NPV of avoided fuel oil purchase, avoided GHG global social costs, and other non-energy benefits for the host customer (via proxy)	Benefits: NPV of added utility revenue
Costs = NPV of added electric generation and capacity costs, added transmission and distribution costs, adverse health impacts from increased electric generation, costs to install heat pump, and program administration	Costs = NPV of costs to incent customer to install heat pump, program administration

As is clear from the above examples, a large range of input values in the Proposed BCA are derived from considerations that are widely delinked from NSPI customers (e.g., health impacts). The PAC by comparison uses values that are relevant to utility economics and the impact on NSPI and its customers (including incentives). The benefit of using PAC as the DSM activity screening is that it can perform both functions – to help assess the DSM components (whether measure, program or plan/portfolio) while also fulfilling the Board's requirements to consider electricity customers.

Would using PAC as the primary screening preclude considering societal benefits and other considerations such as Sustainable Development?

No.

The use of a primary screening tool can help reach conclusions on the cost-effectiveness of a plan, but is not an absolute requirement nor veto on any given plan component. The Board can and should continue to receive information to permit the Proposed BCA ratio to be calculated (such as the impact of GHG emissions), in order to inform its determination as to which DSM must be undertaken.

Would using the PAC instead of TRC or the Proposed BCA lead to less DSM being cost-effective?

Not necessarily. The PAC should not be viewed as a less permissive test, which would rule out more DSM activities. Indeed, in the 2023-2025 DSM plan, the PAC results for most programs were more favourable than the TRC results.[25]

OTHER BCA CONSIDERATIONS

E1's Application relies on the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM"), produced by the National Energy Screening Project. Does E1 appropriately incorporate the principles underlying the NSPM?

No.

The NSPM is a well-regarded manual setting out an independent perspective on Distributed-Energy Resources ("DER") which includes DSM, energy efficiency, and beneficial electrification. The manual is "policy-neutral in that it does not recommend any specific cost-effectiveness tests or policies, but rather supports BCA practices that align with a jurisdiction's policy goals and objectives."[26]

[25] 2022 NSUARB 137, paragraph 85
[26] NSPM For Benefit-Cost Analysis of Distributed Energy Resources. Page i. National Energy Screening Project, 2020.

From the outset, E1 consistently ignores or violates Principle 1 of the NSPM, which is to "Treat DERs as a Utility System Resource" and specifically that:[27]

> DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.

E1 has proposed its BCA include multiple specific inputs that are not consistent with methods and assumptions for alternative resource investments, including discount rate, and balanced plan design such as between residential and business interests.

Why is the E1 proposal on discount rates inconsistent with utility system resources?

In conducting Integrated Resource Planning ("IRP"), utilities typically compare alternative new energy generation resources using their Weighted Average Cost of Capital ("WACC") as a discount rate.

E1 proposes that DSM be evaluated against these resources using a low social discount rate of 2%. This does not meet the concept of using "consistent methods and assumptions" as per the NSPM.

E1 indicates that the social discount rate is appropriate as it is consistent with the guidance of the Treasury Board of Canada.[28], However the referenced sources are for analysis of regulatory proposals (e.g., new rulemaking for federal policy), not for investment in physical infrastructure or electrification activities. The cited policy documents[29][30] give examples of food safety regulations and money laundering regulations, not capital investments in infrastructure. Further, the documents also focus primarily on discount rates primarily linked to the costs of funds[31] such as WACC, but do note that in certain limited circumstances a lower social discount rate may be appropriate.

In any event, the Treasury Board documents are clear: "Regardless of the rate used, the costs and benefits must be discounted using the same rate."[32]

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[27] NSPM, page iv.
[28] E1 responses to IRs from NSEB; IR-5; Exhibit E-5; pdf page 12 of 91.
[29] Policy on Cost-Benefit Analysis from Treasury Board of Canada Secretariat, 2018; Government of Canada. Available: https://www.canada.ca/en/government/system/laws/developing-improving-federal-regulations/requirements-developing-managing-reviewing-regulations/guidelines-tools/policy-cost-benefit-analysis.html
[30] Canada's Cost-Benefit Analysis Guide for Regulatory Proposals, Treasury Board Secretariat, 2019; Government of Canada. Available: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwiki.gccollab.ca%2Fimages%2F8%2F8e%2FCBA_Guide-EN.doc&wdOrigin=BROWSELINK
[31] Ibid, page 34.
[32] Ibid, page 35.

Because the principle for DSM as per NSPM Principle 1 is that DSM should be evaluated on an equal footing as other energy resources (such as new generation), the only reasonable interpretation for any comparison that uses utility savings, avoided generation, etc. is to use the same discount rate as is used for utility IRP, which is the WACC.

If E1 is concerned a WACC discount rate is not sufficiently informative regarding measures or programs whose approval could turn on the specific discount rate selected, E1 may want to provide discount rate sensitivities for those items to assist the Board in understanding the threshold sensitivities, for information purposes.

Why is E1's approach of using balanced plan design problematic?

E1 indicates that in addition to cost-effectiveness, its proposals are designed to reflect balance, such as equitable allocation of investment and savings between residential and business sectors, and access by all market sectors and rate classes, as well as underserved markets.[33]

The NSPM cites the potential that a jurisdiction may have multiple DSM planning criteria, such as to "provide balance across customer types"[34] However, this is generally inconsistent with NSPM Principle 1, unless explicitly established by policy. Just as generation energy resources are compared primarily on economics, cost-effectiveness should be the primary test for DSM. Further, utility resources are not generally designed around equity and access (e.g., a wind developer in the windy eastern portion of the province received a Power Purchase Agreement, so now one from a less-windy western portion of the province should get the next PPA, for balance). The fundamental five Nova Scotia IRP principles are safety, reliability, least cost, decarbonization, and robustness to changes in assumptions.[35]

Unless a jurisdiction has an explicit policy direction regarding balanced access to DSM, this type of criteria should be discouraged in most cases where DSM is funded by customer rates.

Should E1's proposal that BCA be conducted only at the Portfolio level be adopted?

No.

Previous sections of this submission highlighted that the Board cannot fulfill its mandate if screening information or tests are only applied at the portfolio level. For example, a portfolio that includes a long list of highly cost-effective programs could have a limited number of specific unnecessary or frivolous measures that grossly fail cost-effectiveness testing, and could be unidentifiable if testing is only

[33] E1 Evidence, page 6 of 28; Exhibit E-1, pdf page 17 of 450.
[34] NSPM, page 13-11; pdf page 219 of 302.
[35] NSPI Integrated Resource Planning website. Available: https://www.nspower.ca/irp

completed at the Portfolio level. BCA testing at the measure level can identify such proposed outlier activities.

Further, currently spending on DSM in Nova Scotia is primarily (75%) recovered through direct allocation to the participating customer classes.[36] This means that each class will be paying the costs forecast to be spent on delivering DSM to their class. In order to ensure the DSM program complement proposed is beneficial or in the best interests of customers, it would also be appropriate to assess BCA cost-effectiveness metrics at the level of customer class (for at least the major classes). Portfolio level data will not permit this type of analysis.

These concerns about customer class cross-subsidization also suggest NSPI Cost of Service methodology should move towards classifying 100% of DSM costs directly to the participant class.

Is there any relevance to a Participant Cost Test?

Yes.

E1 should be directed to provide information on the results of the PCT by measure (or comparable measures, such as customer payback periods), to indicate whether E1 has proposed a reasonable scale of incentives to achieve positive (but not excessive) beneficial outcomes for participants. Incentives must be paid by utility customers, so evidence is required that these are set at a reasonable level to help achieve cost-effective levels of DSM participation, but not at a level that is excessive nor imprudent to secure participation.

Is there any relevance to measurements considering rate impacts, such as a RIM test?

A RIM test should not be applied as a screening test for energy efficiency, as it can derive excessively narrow metrics and fail to measure proper cost-effectiveness. However, E1 should continue to report rate impacts at the various granularity (measure, program, portfolio) to permit assessment by the Board of customer impacts, including on non-participants.

Are there other concerns with E1's BCA inputs?

Yes. However, this concern may be more appropriately addressed as part of a specific DSM Plan review, rather than a BCA review.

E1 has proposed to estimate the benefits of DSM measures using an estimate of avoided utility generation costs, and avoided GHG emission benefits. In each case, E1 appears to show long-term values

[36] Per Exhibit N-4, Studies and Report 01-04, pdf page 376 of 1000

that are benchmarked to the starting value and increase modestly with inflation.[37] The GHG emissions are also benchmarked to the "Calculated Intensity Metric tonnes/MWh" which appears to be the average NSPI emissions per year divided by the GW.h produced.

This approach to long-term analysis may not be consistent with appropriate utility system planning, nor with standards for Cost-Benefit Analysis (including from the cited Treasury Board documentation), in three ways:

- First, the principle for cost and benefit analysis should be that the analysis considers the impact on the marginal resource. It seems unlikely that the avoided cost of energy in 2035, after considerable investment in the system generation capability, addition of new renewables and storage, and new interconnections, would be the same avoided cost as 2025 increased for inflation. The baseline for comparison of DSM cost-effectiveness should be reflective of the ways that baseline conditions will evolve in future with versus without DSM, and not simple inflationary adders to current estimates.
- Second, the same principle should apply to the analysis of avoided GHG emissions. For example, the apparent use of average GHG intensity for the NSPI system would not appropriately reflect the incremental impact on GHG emissions from pursuing versus not pursuing DSM as an incremental resource. This is because the DSM may disproportionately affect specific types of generation, not the NSPI average.
- Third, E1 should be required to address whether DSM will in fact avoid any electricity-sector GHG emissions, if the maximum permitted emissions are fixed and will be assumed to occur regardless as to whether DSM provides the next supply resource, or whether some other non-emitting resource will provide the same supply.

These observations should inform the E1 approach to the next DSM plan justification.

[37] For example, see E1 response to NSEB IR-26 Attachment 1, Exhibit E-5i. Tab "SCC in 2021 CDN" for the Social Cost of Carbon, and Tab "Other Fuel Impact Electric" for the Electric Avoided Cost.

SUMMARY

What recommendations do you have?

Based on the above considerations, I provide the following conclusions and recommendations for the Board:

1) The current primary TRC test is limited in its ability to singularly inform the Board about essential aspects it must consider (such as whether DSM activities reduce costs for NSPI customers, from a utility perspective). It has been appropriately used in combination with other information to fulfill the Board's requirements. The Board should continue to use more than one primary test.

2) The current TRC test is unbalanced as it includes certain costs (customer costs) without including some of their associated benefits (non-energy customer benefits). E1 was seeking to address this issue, but has gone in the wrong direction (less granular, towards a societal benefit perspective, rather than more granular towards a utility specific perspective). The E1 Proposed BCA test should be rejected as the primary test.

3) Future BCA testing should be based on a balanced consideration of the following tests:

    a. The primary energy efficiency test should be the PAC test, applied at the measure and program levels.

    b. For electrification, the primary PAC test should be applied reflecting added utility revenues as the benefit.

    c. The Proposed E1 BCA test (a societal test) should also be calculated, for information about the broader benefits of proposed DSM activities, programs and plans, to inform the Board about broader considerations, such as Sustainable Development.

    d. Rate impacts, by class, should continue to be reported, at an aggregate level and customer class level, as an input to Board decisions (but a RIM test should not be used as a screening criteria).

4) Using the tests set out in item 4 above, the Board can fulfill the full range of its obligations to consider customer interests (including participants and non-participants) and the broader public interest.

5) E1 should use the NSPI WACC as the discount rate for calculations.

6) E1 should be directed to pursue measures and programs that are cost-effective as the primary criteria, minimizing the other "balanced" criteria in program design to support non-cost-effective measures and programs.

7) E1 should provide calculations of the PCT or customer payback periods, to indicate it has appropriately benchmarked proposed incentives.

8) E1 should ensure that future BCA tests are applied to values for avoided utility costs and GHG emissions that reflect an evolving baseline, and are appropriate for each of the periods in the future horizon being analyzed. E1 should also be required to show that any purported avoided GHG emissions are in fact the result of comparing the utility system emissions with and without the proposed DSM – if the emissions are fixed at a cap based on some outside factor, regardless as to the DSM pursued, there should not be avoided GHG emissions in the DSM evaluation.

APPENDIX A:

RESUME

PATRICK BOWMAN

Principal Consultant
Bowman Economic Consulting Inc.

161 Rue Hebert
Winnipeg, Manitoba
R2H 0A5 CANADA

AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including Depreciation
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

BOWMAN ECONOMIC CONSULTING INC., WINNIPEG, MANITOBA

2020 – current – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation. Member, Society of Depreciation Professionals

Sample Projects:

For Manitoba Industrial Power Users Group (2020 – present; previous involvement since 1998): Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (CentraGas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.

For Industrial Customers of Newfoundland and Labrador Hydro (2020 – present; previous involvement since 2001): Prepare analysis and evidence for Newfoundland Hydro GRA and other rate hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

For Industrial Gas Users Association of Manitoba (2020 - present): Support for cost of service and rate design matters. Testimony before the Manitoba Public Utilities Board.

For Northwest Territories Power Corporation (2020-Present; with previous involvement 2000-2020): Provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity). Support to Government of the Northwest Territories on Crown utility governance, rate policy matters, and project development.

For the BC Association of Major Power Consumers (2020-Present; with previous since 2014): Support for review of BC Hydro Revenue Requirement, Depreciation, Cost of Service, Rate Design, Interruptible Rates, and stepped industrial rates.

For Northwest Territories Energy Corporation (2021-Present, with previous involvement 2003 - 2013): Provided analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects. Assist in planning stages and contract review for new LNG supply to Inuvik. Assist in Board of Director's review of corporate roles for commercial versus regulated activities.

For Vale Newfoundland (2022-present): Assist in negotiations regarding new industrial contract and interruptible power framework.

For J. D. Irving Ltd. (2022-Present); previous involvement 2017-2018): Support in regulatory proceedings before the New Brunswick Energy and Utilities Board on matters of Revenue Requirement, customer class and rate design, and smart meter implementation.

For the PEI Federation of Agriculture (2023-present): Support in regulatory review of Maritime Electric Rate Design proceeding.

For the Industrial Group of Nova Scotia Power Inc. (2024-Present): Technical support to Cost of Service working group and negotiations on methodology.

For the City of Langford (2024-present): Assistance in development of alternatives for renegotiation of sewer services supply agreement.

For Yukon Energy Corporation (2024-present): Provide analysis regarding net salvage regulatory account options.

For the Ontario Energy Board (OEB) (2025): Act as facilitator for distribution rate application for Welland Hydro.

For Nelson Hydro (2020-2025; with previous involvement since 2013): Development and updating of a Cost of Service model. Support in regulatory filings before the BC Utilities Commission including Revenue Requirement and Generic Cost of Capital.

For a law firm representing the Government of Alberta (2024): Assistance in calculation of depreciation rates for the purposes of property taxation of industrial property.

For the Manitoba Public Interest Law Centre (2024): Technical support to working group for Brokenhead Ojibway Nation in consultation process with Manitoba Hydro regarding new development and licencing of existing projects on the Winnipeg River and Lake Winnipeg Regulation.

For confidential client (2021-2023): Assist in investigations regarding potential hydrogen development opportunities in Canada.

For Corner Brook Pulp and Paper (2021-2022): Assist in negotiations regarding new industrial contract and interruptible power framework.

INTERGROUP CONSULTANTS LTD., WINNIPEG, MANITOBA

1998 – 2024 – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability.

Sample Projects:

For the Office of the Utilities Consumer Advocate of Alberta (2016 - 2024): Analysis and strategic support of Government agency representing the interests of small utility customers. Addressed matters of utility rates and asset depreciation matters, covering electrical transmission, distribution, gas transmission, distribution, project development, and regulated utility service providers.

For the Ontario Energy Board (OEB) (2024): Review regulatory commission policies and practices with respect to intervenor participation, including Consumer Advocate options, budgets, etc.

For the Ontario Energy Board (OEB) staff (2022-2023): Support the OEB staff in the Enbridge Gas Distribution 2024 rate re-basing application, focused on matters of utility assets and depreciation.

For Vancouver Airport Fuel Facilities Corporation (2018-2022): Provide analysis and evidence in support of tolls for common carrier jet fuel pipeline, before the BC Utilities Commission.

For City of Chestermere (2015 - 2022): Analysis of various rate proposal from Chestermere Utilities Inc. to the City of Chestermere.

For a law firm (2021-2022): Provide analysis in support of hydro generation valuation in northwestern Ontario.

For Taxi Coalition of Manitoba (2021): Support for regulated vehicle insurance rate design, provided by Crown insurer. Testimony before the Manitoba Public Utilities Board.

For Jamaica Public Service (2018-2020): Assist in preparation of regulatory rate filing, including cost of service, revenue requirement, and plans to address utility losses and power theft.

For Government of Ontario (2018): Support to department undertaking and supporting preparation of a Modernization Review of the Ontario Energy Board.

For Yukon Energy Corporation (1998 - 2015): Provide analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, depreciation, net salvage, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers.

For City of Swift Current (2013 - 2014): Utility system valuation.

For Municipal Customers of City of Calgary Water Utility (2012 - 2013): Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).

For Yukon Development Corporation (1998 - 2012): Prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

For NorthWest Company Ltd. (2004 - 2006): Review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

Sample Projects:

For Government of Canada – Justice (2022-2023): Provide opinion evidence for proceeding before the Specific Claims Tribunal regarding transmission line valuation for 1950s transmission line crossing reserve land.

For the Government of the NWT (2021-2023): Assist in developing rate strategies and operational costing for major new generation and transmission facilities in NWT.

For Kivalliq Hydro-Fibre Link (2020-2022): Review and provide comment on drafts of business case for new transmission and fibre optic link to Nunavut.

For Hualapai Tribal Utilities (2017-2018): Support Tribal utility association in preparation of feasibility study to take over operations of power distribution on tribal lands.

For Government of NWT (2015-2016): Assist in analysis for hydro system resiliency study in response to Snare River drought.

For New World Dairy (2015-2017): Assist in negotiations regarding Non-Utility Generation and interconnection with Newfoundland Hydro

For Yukon Energy Corporation (2005 - 2015): Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

For Northwest Territories Power Corporation (2005 - 2012): Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out interconnect to southern jurisdictions. Conduct business case analysis regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

For Tolko Manitoba (2014-2015): Assist in negotiations with Manitoba Hydro regarding expansion of steam generation capabilities.

For Kwadacha First Nation and Tsay Keh Dene (2002 - 2004): Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

For Manitoba Hydro Power Major Projects Planning Department (1999 - 2002): Initial review of socio-economic impacts of proposed new northern generation stations and transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

For Manitoba Hydro Mitigation Department (1999 - 2002): Provided analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

For International Joint Commission (1998): Analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.

For Nelson River Sturgeon Co-Management Board (1998 and 2005): An assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

GOVERNMENT OF NORTHWEST TERRITORIES, YELLOWKNIFE, NORTHWEST TERRITORIES
1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony on all areas of Revenue Requirement, including Depreciation	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation, Support to Legal Counsel	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
Newfoundland Hydro	Depreciation Methodology	Analysis, Support of Expert Witness, Advisor to Legal Counsel	NLPUB	Newfoundland Industrial Customers	2012	No
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Testimony and Negotiated Settlement, including Depreciation	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlemen
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on Depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlemen
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on Depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation for SCADA Depreciation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence including Depreciation	AUC	UCA	2018	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018	Yes
Newfoundland Hydro	Cost of Service Methodology	Analysis and Case Preparation	NLPUB	Newfoundland Industrial Customers	2018	No
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Efficiency Manitoba	3 yesar Energy Efficiency Plan Review	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2019	Yes
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony. Included Depreciation Rate Mitigation Options	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No
BC Hydro	Fiscal 2020 to 2021 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence	BCUC	Association of Major Power Consumers of BC (AMPCBC)	2019-2020	Yes
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence on Depreciation and Valuation matters	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coalition	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis and support of intervenor evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWT PUB	NTPC	2022	No
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II (Cost of Service and Rate Design) Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	No - Written Process only
Centra Gas Manitoba	2021 Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence	MPUB	Industrial Gas Users of Manitoba (IGU)	2021-2022	No - Written Process only
BC Hydro	Fiscal 2022 to 2025 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence, primarily focused on depreciation	BCUC	AMPCBC	2022	Yes
DERS	2023 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2023	No - Negotiated Settlement and written process
EDTI	2023-2025 Transmission Facility Owner Revenue Requirement	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement and written process
BC Hydro	2021 Intergrated Resource Plan	Analysis, Preparation of Intervenor Evidence	BCUC	AMPCBC	2023	Yes
Enbridge Gas Inc (EGI)	2024 Rebasing	Analysis, Preparation of Intervenor Evidence	Ontario Energy Board (OEB)	OEB Staff	2023	Yes

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
New Brunswick Power	Matter 529 - 2022 Rate Design Application	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2023	Yes
Manitoba Hydro	2023-24 and 2024-25 GRA	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2023	Yes
Manitoba Hydro	SCT 4002-12 Brokenhead Ojibway FN vs HMTK	Opinion on Transmission Line Valuation	Specific Claims Tribunal	Government of Canada	2023	No - Negotiated Settlement
NTPC	Hay River Franchise Disposition	Analysis, support preparation of regulatory principles, rate impacts	NWT PUB	NTPC	2024	Yes
Nelson Hydro	Generic Cost of Capital Review - Stage 2	Support to Nelson Hydro on preparation of utility evidence	BCUC	Nelson Hydro	2024	No
New Brunswick Power	Matter 554 - Class Cost Allocation Study Methodology Review	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2024	Yes
Naka Power (NWT)	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	NWT PUB	NTPC	2025	Yes
NTPC	2024-25 and 2025-26 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2025	Yes
Centra Gas Manitoba	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	MPUB	IGU	2025	Yes
Fortis BC	2025 Cost of Service and Revenue Rebalancing	Analysis, Support of Intervenor position	BCUC	BC Municipal Electrical Utilities	2025	No
Nova Scotia Power	M11475 Cost of Service Study	Analysis, Support of Intervenor position	Nova Scotia Energy Board	Industrial Group (IG)	2024-ongoing	pending