

**PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO MATTER M12661
NOVA SCOTIA POWER
EXTRA LARGE INDUSTRIAL DEMAND TARIFF**

Submitted to:

The Nova Scotia Energy Board
on behalf of
Industrial Group

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May 8, 2026

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1.0 INTRODUCTION

This Pre-filed Testimony has been prepared by Mr. Patrick Bowman of Bowman Economic Consulting Inc., retained by the Nova Scotia Industrial Group ("IG"). The IG includes Nova Scotia Power ("NSP") customers served in the Large Industrial ("LI") and Medium Industrial ("MI") classes.

This testimony reviews and assesses relevant aspects of the NSP Extra Large Industrial Demand ("ELID") Tariff Application ("Application") proposed to be applicable to service to Port Hawkesbury Paper Company ("PHP"). The Application was filed with the Nova Scotia Energy Board ("Board") dated December 29, 2025. For simplicity, the term "Board" as used in this submission includes both the Energy Board, and its predecessor, the Utility and Review Board (also known as the "NSUARB"). In addition, some of the functions ascribed to NSP will eventually become part of the Independent Energy System Operator ("IESO") but for the purposes of this evidence, references to the dispatch role consistently refer to NSP.

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.
- 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.

As set out in Appendix A, Mr. Bowman has been involved in regulated utility regulation, planning, energy efficiency, cost allocation and rate design 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.

1.1 Findings and Recommendations

The proposed ELID rate is complicated and unusual in utility rate regulation. No comparable rate could be identified in Canada, particularly for a major customer on a regulated utility system.

Despite this, the ELID carries forward the service concept of the existing Extra Large Industrial Active Demand Control ("ELIADC"), where the PHP load can be managed by NSP to achieve cost benefits for the system overall. In principle, this is a beneficial arrangement.

1 The proposal by NSP with respect to pricing the ELID service does not properly reflect the cost or value of
2 the service provided, nor fair and consistent treatment between PHP and other customers served with
3 bundled service (via Above The Line ("ATL") service in the Cost of Service ("COS") study). In order to
4 address issues with the rate, the following recommendations are addressed in this evidence:

5 **RECOMMENDATION 1:** The capacity value used in the COS for PHP should be representative of
6 the expected PHP average demand based on total forecast energy requirements (prior to non-
7 dispatchable wind energy credits) at a high load factor. Absent any updated values provided by
8 NSP consistent with the concept of a high load factor Customer Baseline Load ("CBL"), the value
9 should be set at 120 MW (approximately 127.2 MVA).

10 **RECOMMENDATION 2:** The rights provided NSP in the ELID Dispatchability Rider ("DR") should
11 include practical control of dispatch at times when the system has small reserve margins or supply
12 constraints. As proposed, the purported control only arises from general economic price signals.

13 **RECOMMENDATION 3:** The DR dollar value credit proposed to be allocated 100% to PHP risks
14 over-crediting PHP for the value of DR, and harming other customers. This arises in part because
15 the theoretical CBL against which the PHP DR activities will be measured does not reflect what
16 would likely be the default PHP operation absent the DR. Separately, there has been experience in
17 Nova Scotia of the CBL-type calculation over-valuing the contribution of dispatchable load. In order
18 to address this issue, the Board should retain some form of benefit sharing, as is in place under
19 the current tariff (ELIADC), rather than 100% allocation of all theoretical savings to PHP.

20 **RECOMMENDATION 4:** Given the lack of practical interruptibility of PHP loads at times of system
21 constraint, there should be little to no credit provided via an Interruptibility Rider ("IR") in the ELID
22 tariff.

23 **RECOMMENDATION 5:** There is no basis for providing PHP with a priority interruptibility credit,
24 given (a) PHP is rarely, if ever, interruptible in practice under the IR, and (b) the priority interruption
25 adds nothing to the system in terms of extra resources, in exchange for the added credit provided
26 to PHP.

27 **RECOMMENDATION 6:** The Board should ensure that the Operating Procedures are specifically
28 noted as a matter for Board approval. Further the Board should clarify that reporting on the DR
29 status, including estimates of the annual DR to be funded by ATL customers, is provided at least
30 quarterly by NSP.

31 **RECOMMENDATION 7:** The Board should not adopt the proposals from PHP to alter the rate as
32 proposed by NSP. This includes adjusting the PHP peak load to 8 MW in the COS study, adjusting

1 the PHP Revenue-to-Cost ratio to 100%, and providing PHP with added value related to ancillary
2 services for which it is already compensated via the DR.

3 **2.0 NSP ELID RATE PROPOSAL**

4 PHP is NSP's largest customer, forecast in the most recent NSP GRA to use over 810 GW.h per year for
5 2026, with the hourly on-site demand able to vary from 12 MW¹ to 160 MW.² PHP now indicates the load
6 for 2026 will total 774 GW.h³.

7 Service to PHP is presently provided under the Extra Large Industrial Active Demand Control ("ELIADC")
8 tariff. Under the ELIADC, the load of PHP is subject to Active Demand Control ("ADC") where NSP is given
9 a dispatch role over the timing for the use of power at PHP. PHP will set the total amount of energy it
10 proposes to consume in a period, but NSP will indicate to PHP the preferred timing for the consumption of
11 this energy.

12 The proposed new ELID tariff retains this dispatch role for NSP, which is now termed the Dispatchable
13 Rider ("DR"). The DR is described as being "essentially the same" as the ADC.⁴ As a result, the current NSP
14 ELID proposal is largely a new manner of setting rates for what is portrayed as essentially the same utility
15 service as existed under the ELIADC.

16 The fundamental aspects of the ELID tariff as proposed are as follows:

- 17 1. The rate for the ELID service will be set using **"above the line" ("ATL") Cost of Service**
18 **("COS") techniques**. This means that the ELID customer will receive an allocation of costs
19 through the NSP COS study, similar to other regulated bundled service customers. As an ATL
20 customer, the ELID tariff customer will be allocated the average or embedded costs of supply on
21 NSP's system (both fixed and variable).
- 22 2. The ELID customer will then receive a **DR credit**, which is proposed to provide it with 100% of
23 the net savings that arise due to the customer operating in a manner that is more optimal than a
24 defined theoretical Customer Base Line ("CBL"). The CBL is designed under the assumption that
25 the customer, absent the DR, would operate at a very high-load factor (i.e., a very flat load
26 throughout the year). The proposed mechanics provide that this credit will be provided to PHP

¹ Of the 12 MW, 4 MW is indicated to be related to operating the biomass plant, which is a net positive to supplying grid loads, so only 8 MW is considered to be PHP's native peak.

² Matter M12661, Exhibit N-3, pdf page 4; Exhibit N-1, pdf page 5.

³ Matter M12661, Exhibit N-3, pdf page 11 of 14. This is the PHP projected consumption before Goose Harbour Lake wind is applied to PHP load, which is estimated at 154.61 GW.h in 2026.

⁴ Matter M12661, Exhibit N-10, pdf page 25.

1 through the Fuel Adjustment Mechanism ("FAM") allocation process as a dollar value credit, and
2 will be allocated so as to be paid for by all ATL customers.

3 3. The ELID customer is also proposed to receive an **Interruptible Rider ("IR") credit** applied
4 against the amount of capacity costs that the customer is allocated, for capacity supplies which are
5 subject to forced interruption at times of system constraints. Similar to the Large Industrial
6 interruptible customers, this credit will be allocated through the COS study.

7 4. In addition, the ELID customer is proposed to receive a **priority interruptible additional credit**
8 which is equal to a 10% premium on top of the IR, based on the premise that the ELID customer
9 would be the first to be interrupted at times of system constraint.

10 A complicating factor of the ELID tariff is that PHP is also committed to acquiring power through NSP's
11 system from the Goose Harbour Lake wind farm, which is owned by PHP Wind Limited ("PHPW"). The wind
12 is expected to generate over 500 GW.h in 2027.⁵ The calculations included in the FAM are intended to
13 ensure that the Goose Harbour Lake wind output Subject Energy Amount ("SEA") is sold to PHP before any
14 standard tariff energy.

15 This order of operations for pricing the PHP supply is important for logical consistency under the NSP
16 proposal:

- 17 - First, PHP becomes an ATL customer premised on using power at the CBL. This power is net of
18 expected wind generation, so approximately 300 GW.h in 2027 (approximately 800 GW.h of usage,
19 less 500 GW.h of wind).
- 20 - Against that CBL, PHP can secure benefits from shaping their load, by way of access to the DR
21 process. The DR is available to all 800 GW.h of PHP's projected consumption.
- 22 - Then, having had its load shaped via the DR, PHP may also be able to offer interruptible demand
23 to the system and be credited for that offering, similar to other interruptible customers.
- 24 - Finally, should value be demonstrated, there may be a basis for PHP to accept that its demand
25 interruptions will occur on a priority basis to other interruptible customers, for which it can receive
26 additional compensation.

27 The proposed ELID tariff is fundamentally different than the existing ELIADC rate, which allocates costs to
28 PHP on the basis of below the line ("BTL") COS principles. These principles are effectively based on
29 incremental pricing. In this manner the ELIADC tariff makes limited contribution towards paying the fixed
30 costs of NSP's operation, but receives service using higher priced marginal source of power as available

⁵ Matter M12661, Exhibit N-3, pdf page 11 of 14.

1 from time-to-time.⁶ Similar incremental priced tariffs are common in Canada (though rarely at this scale for
2 an in-province customer).

3 Many of the specific parameters for the tariff in 2026 and 2027, such as the peak loads and energy amounts,
4 were presented as part of the recent NSP General Rate Application ("GRA") negotiated settlement.
5 However, that settlement provided that in relation to the current application, "it remains open for all Parties
6 to take any position they so choose, including whether each of the PHP ADC and tariff filing(s) is inconsistent
7 with the load characteristics and basic tariff structure as set out above". The load characteristics in the GRA
8 settlement provided as follows:⁷

- 9 - PHP would become an ATL customer effective January 1, 2026
- 10 - PHP's firm (non-interruptible) load was set at 8 MW.⁸
- 11 - PHP's firm plus interruptible load was forecast at 65 MW
- 12 - PHP's energy is based on a forecast usage net of the Goose Harbour Lake wind farm.
- 13 - The dollar value of IR credit was the same as for the Large Industrial class.
- 14 - The priority interruptible credit was set at an additional 10%

15 The manner in which NSP will control PHP load is to be set out in a set of Operating Procedures. NSP has
16 proposed that these procedures not be subject to regulator approval, based on the premise that the only
17 party affected by the effectiveness of the procedures is PHP, as they are proposed to receive 100% of the
18 credit for any savings achieved via the DR.⁹ As a result, NSP submits that the relative effectiveness or
19 ineffectiveness of the Operating Procedures are of no concern to other regulated customers, as follows:¹⁰

20 The ELID Tariff is designed such that Fuel Adjustment Mechanism (FAM) customers should
21 be "indifferent" to the design of the Operating Procedures or the effectiveness of the tool
22 as the cost and benefits of compliance with the procedures will flow to PHP, with a neutral
23 effect on the FAM.

24 NSP proposes that reporting on the DR credits, and the amounts that will be payable by other customer
25 classes, will only occur on an annual basis, after the end of the tariff year.¹¹

⁶ Matter M12661, Exhibit N-3, pdf page 8 of 14.

⁷ Matter M12661, Exhibit N-1, Attachment 4.

⁸ This is the peak related to the 3 Coincident Peaks (CP) which is the basis for allocating demand-related costs in the COS study.

⁹ Matter M12661, Exhibit N-6, pdf page 1446 of 1474.

¹⁰ Matter M12661, Exhibit N-6, pdf page 1446 of 1474.

¹¹ Matter M12661, Exhibit N-1, pdf page 27 of 50.

1 No other comparable rate could be identified in Canada, where a customer is given an ATL rate (e.g., pays
2 a base rate that is developed to include a share of embedded resources, including older low-cost resources)
3 but then separately given effectively unlimited access to marginal or incrementally costed adjustments tied
4 to increases or decreases in the pattern of usage over time throughout the year, which flow to the credit
5 of their own account.

6 In contrast to NSP's proposals for the ELID tariff, PHP has further proposed a number of revisions, which
7 are addressed in section 4.0 of this evidence.

8 **3.0 ISSUES WITH NSP'S PROPOSED ELID TARIFF**

9 The proposed ELID tariff is fundamentally an attempt to cost and price the service that PHP is proposed to
10 receive. The ELID as proposed by NSP contains a number of assumptions and calculation approaches that
11 do not appear to properly reflect the cost or value of the service provided, nor fair and consistent treatment
12 between PHP and other customers served ATL.

13 There are four fundamental issue areas with the ELID tariff as proposed by NSP:

- 14 - Issues in the COS as it is applied (before application of the DR credit)
- 15 - Issues with the proposed application of the DR credit
- 16 - Issues with the proposed IR credit
- 17 - Issues regarding transparency and reporting

18 Combined they lead to a tariff framework that does not reasonably price the service being provided to PHP.

19 **3.1 Issues in the COS for establishing the ELID ATL Costing (Before Application of** 20 **the DR)**

21 In the first step of the rate development, PHP is included in the NSP COS study as an ATL customer.

22 The PHP usage in the COS is intended to reflect the total forecast energy consumption by PHP, as
23 outlined in the GRA negotiated settlement: "PHP energy will be based on PHP's forecast usage for the
24 test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm"¹²

25 As an ATL customer, PHP's characteristics in the COS study will shape the base rate components that will
26 be paid by PHP. This includes the energy charge, demand charge, etc. The COS study output will not be

¹² Matter M12661, Exhibit N-1, pdf page 41 of 50.

1 the final determinant of what PHP is to be billed, as that will be dependent on the subsequent rate add-
2 ons (e.g., DR, IR).

3 Since the DR is to credit PHP for the savings that arise from its actual load dispatch for its total load (i.e.,
4 800 GW.h), as compared to a CBL, the COS inputs should be based on the CBL assumption, including that
5 PHP will operate at a high load factor across the 800 GW.h. As a high load factor customer (prior to DR),
6 PHP would be expected to have a load profile that is generally flat – or largely consuming the same average
7 capacity throughout the year during operating periods.¹³ This load should establish the costing appropriate
8 to the PHP load prior to DR, and should include all reasonable demand requirements consistent with the
9 CBL assumptions.

10 NSP has not provided a specific CBL demand load, but has provided the PHP average operating load in
11 response to Information Requests, noting PHP's "average load" is a confidential value, but is "approximately
12 15 times the 8 MW figure"¹⁴ (which would yield 120 MW). The standard CBL running load values for 2023,
13 2024 and 2025 are also provided in confidential filings, and do not contest this range.¹⁵

14 These data indicate support for a PHP capacity load in the COS of 120 MW.

15 It is acknowledged that 120 MW for 800 GW.h is only approximately a 76% load factor, which may be
16 below the level contemplated by the concept of a CBL for PHP. If NSP is able to offer a different flat profile
17 demand level for PHP, consistent with CBL assumptions, then such value may be more appropriate than
18 the 120 MW estimated above. Absent such update, this 120 MW demand value should be applied in the
19 COS as the baseline for allocating NSP transmission assets and generation.

20 **RECOMMENDATION 1:** The capacity value used in the COS for PHP should be representative of
21 the expected PHP average demand based on total forecast energy requirements (prior to non-
22 dispatchable wind energy credits) at a high load factor. Absent other values provided by NSP
23 consistent with the concept of a CBL, the value should be set at 120 MW.

24 The capacity pricing in practice will be applied to PHP effectively as a fixed cost, as the PHP actual peak
25 demand each month will be modified for the DR and will not be used as the basis for calculation of monthly
26 demand charges. This fixed dollar value for ELID capacity costs should be updated at future GRAs, using
27 the same principles (i.e., based on PHP total load, assuming usage at a high load factor).

¹³ Matter M12661, Exhibit N-10, pdf page 67 of 306.

¹⁴ Matter M12661, Exhibit N-5, pdf page 204 of 206.

¹⁵ M12661, Exhibit N-10, Attachment to Synapse IR-24, Att. 01 CONF.

3.2 Issues Associated With Application of the DR

The DR is a highly accommodating and beneficial aspect of the ELID rate to PHP. It also appears to be unprecedented in Canada.

Not only does PHP secure the ability to access approximately 300 GW.h of ongoing net energy from the embedded cost resources of NSP (via the COS study), but PHP also secures the ability via the DR to be compensated for any load variation (compared to the CBL) that reduces incremental system costs at the full marginal value, on all 800 GW.h of load that PHP expects to consume. This opportunity is provided even though 500 GW.h of the 800 GW.h was not purchased from NSP in the first place, but instead comes from PHP's own wind.¹⁶

While this rate structure is clearly highly valuable to PHP, the DR concession to PHP is further enhanced by NSP's proposal that the purported "demand control" or "dispatch" rights that NSP secures through the tariff are not, in fact, control in any meaningful sense. Under NSP's proposal, PHP is given unlimited opportunity to benefit from shifting its load, but no obligation to do so at any time. Specifically, NSP notes:

Like Active Demand Control (ADC) in the ELIADC Tariff, the Dispatchable Rider (DR) in the ELID Tariff provides NS Power with the capability to dispatch PHP up and down dynamically at all times, including during system peak, provided such changes fall within the agreed Operating Mode Characteristics Schedule, the final communicated PHP shutdowns, and the ADC Operating Procedure. However, under the Operating Protocols for DR which remain under development with PHP, PHP will have the right to refuse such dispatch direction, subject to the System Operator approval.

In the Technical Conference on April 24, 2026, NSP further clarified these provisions in response to questioning:¹⁷

[Q:] Ignoring the IR, does NSP's power to actively manage arise only through economic signals (i.e., can PHP ignore DR price signals and operate how they want without restriction, but at a net cost to their DR credit)? Or can NSP force PHP consumption profiles under the DR?

[A:] Yes, under the DR PHP can "ignore DR price signals and operate how they want without restriction, but at a net cost to their DR credit." NS Power cannot "force PHP consumption profiles under the DR."

¹⁶ These values represent the ongoing load projections once Goose Harbour Lake wind is online.

¹⁷ Matter M12661, Exhibit N-18, pdf page 5 of 20.

1 NSP has estimated that the fully optimized credit could be up to \$11 million per year, but is unable to
2 provide the calculation of this value.¹⁸ NSP estimates half of this may be reasonably achieved by PHP each
3 year, but also notes that over time this may grow if PHP becomes more adept at maximizing DR value.¹⁹
4 Based on the COS prepared using NSP assumptions, even a \$5.5 million credit would offset approximately
5 7% of the PHP ATL costs, while the full \$11 million in savings would yield 14% in reductions.²⁰

6 It is not apparent why NSP would want to grant PHP the broad right to refuse dispatch direction under the
7 DR, particularly during periods when such conditions as small reserve margins prevail on NSP's system.
8 The DR opportunity offered to PHP is highly economically valuable and should appropriately come with
9 durable obligations to NSP, not just economic incentives to PHP. Further, PHP describes the DR service
10 they are under as being "much the same as a dispatchable power generation facility."²¹ However, a
11 dispatchable power generation facility in rate base can be controlled by the operator, not just economically
12 incented to produce power.

13 In exchange for this very accommodating tariff structure, the DR mechanism should include stronger rights
14 for NSP to enable or ensure PHP load variation that is in keeping with the description as being "control" or
15 "dispatch". This is most particularly the case for acute system hours.

16 **RECOMMENDATION 2:** The rights provided NSP in the ELID Dispatchability Rider ("DR") should
17 include practical control of dispatch at times when the system has small reserve margins or supply
18 constraints. As proposed, the purported control only arises from general economic price signals.

19 A further issue with NSP's proposal is that the DR credit is proposed to be allocated 100% to PHP, based
20 on the representation that other customers are "held harmless" from the DR, as follows:²²

21 The compensation for providing the service is quantified based on the system cost savings
22 provided by the service and as such other ATL customers are held harmless.

23 Given the discussion is about a credit for a more optimized system, it would be more accurate to indicate
24 other customers are held benefit-less, rather than held harmless. It is important to note that under the
25 current ELIADC offering, the savings achieved by PHP's load pattern are shared 75% to other customers,
26 and 25% to PHP.²³ NSP indicates the change to credit 100% of the savings to PHP is appropriate due to

¹⁸ Matter M12661, Exhibit N-10, pdf page 68 of 306, and the response to Synapse IR-16 Attachment 1 CONF which provides only hard entered values for system costs.

¹⁹ Matter M12661, Exhibit N-10, pdf page 68 of 306.

²⁰ Matter M12661, Exhibit N-1, pdf page 11 of 50 and Matter M12661 Exhibit N-7, pdf page 6 of 14. The total ATL COS for PHP is estimated at \$81.4 million per Matter M12451, Exhibit N-92, pdf page 88 of 280. Note that the \$81.4 million is already a cost calculated from the COS study that includes the assumption of PHP operating in an optimized way, so is not the inherent CBL-based cost for PHP.

²¹ Matter M12661, Exhibit N-3, pdf page 5 of 14.

²² Matter M12661, Exhibit N-1, pdf page 11 of 50.

²³ Matter M12661, Exhibit N-7, pdf page 8 of 14.

1 PHP becoming an ATL customer, and bearing a portion of the fixed costs of the system.²⁴ NSP fails to note
2 that by becoming an ATL customer, PHP has simultaneously removed its exposure to the high (and
3 uncertain) marginal cost generation, and such costs are now borne by all customers. So the move to ATL
4 is a trade-off for PHP including benefits and costs, not solely a new cost.

5 More substantively, the design of the proposed DR credit (which is to be recovered from ATL customers in
6 the FAM) presumes that, absent the DR, PHP would have a near-perfectly optimized high load factor load
7 profile (the CBL). However, even PHP indicates this CBL profile is not likely, specifically noting: "The market
8 for paper is somewhat seasonal with winter and summer months having generally less demand than spring
9 and fall. PHP's energy demand corresponds to this seasonal variance."²⁵ As spring and fall are the generally
10 lower cost seasons for NSP, it appears likely that PHP would naturally have a lower cost load than would
11 be represented by the assumed high load factor CBL. For this reason, crediting PHP with the full incremental
12 savings as compared to the theoretical baseline of a CBL load risks excessively crediting PHP and harming
13 other ATL customers.

14 It is further noted that under the ELIADC, there has been an identified issue with the CBL-based calculation
15 of benefits overvaluing the actual net benefit achieved by the ADC service. The conclusions of Board
16 consultant Bates White indicated the ELIADC did "not perform as expected" and were in fact 56% lower
17 than expected. The report indicates that the rate operated "in a way that may have imposed costs on other
18 customers", as cited in a past Board ruling²⁶.

19 This issue of risks of overcompensation of PHP being a burden to ATL can be addressed in one of two
20 ways. Either the CBL can be amended to make it more representative of the expected PHP load, e.g.,
21 reflective of the seasonal market for paper. Or alternatively, the credit can be based on the CBL, but to
22 protect against overvaluing the DR, the calculated dollar value of savings can be shared between PHP and
23 other ATL customers. The latter appears to be a better approach, as it accords with current experience
24 under the ELIADC, and is simpler to implement.

25 **RECOMMENDATION 3:** The DR dollar value credit proposed to be allocated 100% to PHP risks
26 over-crediting PHP for the value of DR, and harming other customers. This arises in part because
27 the theoretical CBL against which the PHP DR activities will be measured does not reflect what
28 would likely be the default PHP operation absent the DR. Separately, there has been experience in
29 Nova Scotia of the CBL-type calculation over valuing the contribution of dispatchable load. In order

²⁴ Matter M12661, Exhibit N-1, pdf page 10 of 50.

²⁵ Matter M12661, Exhibit N-11, pdf page 3 of 5.

²⁶ 2025 NSEB 2, para 30, which notes: "As noted, Bates White said other customers did not fully realize the projected benefits under the ELIADC Tariff"

1 to address this issue, the Board should retain some form of benefit sharing, as is in place under
2 the current tariff (ELIADC), rather than 100% allocation of all theoretical savings to PHP.

3 **3.3 Issues With The Proposed IR**

4 The ELID proposes that in addition to the DR control that NSP has over PHP's load, PHP will also be provided
5 with a separate credit for being interruptible at times of system constraints. This credit is proposed to apply
6 to all PHP demand over 8 MW. However, the evidence indicates that PHP does not actually experience
7 interruptions under any interruptibility provisions that now exist, as PHP will have already been dispatched
8 down to minimal loads under the DR in almost any circumstance that would require interruptibility.

9 Specifically, the evidence notes as follows:²⁷

10 During periods of capacity scarcity, generally PHP load has already been dispatched down
11 and thus no PHP load is available to participate in the interruption process.

12 More specifically, NSP indicates as follows:²⁸

13 For all 25 instances where [Large Industrial] IR customers were interrupted in the period
14 2022-2025 inclusive, PHP's load was either dispatched down by NS Power Energy
15 Marketing ahead of time due to forecasted system conditions or dispatched down in real-
16 time by the NSPSO in response to system conditions.

17 Further in response to a question about interruptions since 2020, NSP noted:²⁹

18 There have been no interruption-related load reductions initiated for PHP during the period
19 requested.

20 The same pattern is expected under ELID:³⁰

21 In general, in day-ahead and intra-day planning, PHP load will be economically dispatched
22 down during hours when the margin between generation plus reserve and load is small.
23 In these hours, PHP typically will not have load available to provide operating reserve, nor
24 be available for interruption

25 This recent actual experience arose under the ELIADC with the existing dispatch rights and the existing
26 (priority) IR credit, at a time when NSP only held the power to dispatch PHP using economic incentives.

²⁷ Matter M12661, Exhibit N-10, pdf page 62-63 of 306.

²⁸ Matter M12661, Exhibit N-10, pdf page 10 of 306.

²⁹ Matter M12661, Exhibit N-9, pdf page 13 of 24.

³⁰ Matter M12661, Exhibit N-6, pdf pages 1387-1388 of 1474.

1 However, as noted above, it is recommended that new ELID contain stronger dispatch rights for NSP that
2 would make it even more likely that PHP is already dispatched to minimal load under conditions likely to
3 lead to calls for interruption than was the case under the ELIADC.

4 For the other Large Industrial customers served under interruptibility rights, the customers will be operating
5 under their normal tariff (without any type of DR) at the time of any likelihood of interruption. However,
6 there is no guarantee that the customer will be operating at 100% full load at these moments. As a result,
7 the dollar value of credit applied to Large Industrial interruptible customers is adjusted by the load factor
8 of the class related to their expected usage at the time of system peak.³¹ If the load were not adjusted in
9 this manner, Large Industrial customers would receive the full \$13.107/kVA/month value of interruptible
10 demand (for usage coincident with system peak), rather than the current value of \$7.638/kVA/month in
11 2026.³²

12 This principle of reduced credit for interruptibility is based on the premise that if the customers only have
13 significant interruptible loads in theory, but in practice they are often operating at a lower load at the time
14 of system peak, then their Large Industrial interruptibility value to the system would be small, and thus the
15 provided IR credit should be reduced. Were the same principle applied to the ELID, the consequent
16 adjustment to the value of PHP's interruptibility would lead to minimal value for any ELID IR, since PHP's
17 expected usage (after the DR is applied) would yield very little load that would likely be available to NSP
18 to interrupt.

19 **RECOMMENDATION 4:** Given the lack of practical interruptibility of PHP loads at times of system
20 constraint, there should be little to no credit via Interruptibility Rider ("IR") provided in the ELID
21 tariff.

22 The ELID also proposes that PHP be granted an additional credit for "priority" interruptibility.

23 Regardless of any priority status claimed, the total amount of interruptible load available to NSP remains
24 the same irrespective of the order in which that load may be interrupted. There is no service benefit to firm
25 ATL customers from reordering the interruption list. In practice, the Large Industrial customers who are
26 not on Telemetry and Control ("T and C") are the first to be interrupted (despite any priority interruption
27 credit provided to PHP) and the Large Interruptible T and C customers are only interrupted later in the
28 stacking sequence with PHP interruptions (if any) slated to occur immediately ahead of Large Industrial
29 IR.³³ The Large Industrial customers who invested in T and C provide an additional benefit to NSP from
30 being able to be considered Operating Reserve during system constraints, which PHP cannot provide as it

³¹ Matter M12661, Exhibit N-5, pdf page 2 of 206.

³² Matter M12661, Exhibit N-1, pdf page 8 of 50.

³³ Matter M12661, Exhibit N-10, pdf page 63 of 306.

1 is already dispatched down under the DR (for which it would already be receiving a DR credit), and the
2 PHP load is therefore not available to the system for Operating Reserve services at these times.

3 Given this profile, combined with the fact that PHP is rarely if ever available to be interrupted under the IR
4 because it is already curtailed under the DR, there does not appear to be any justification for the Priority
5 Interruptible 10% premium paid to PHP.

6 **RECOMMENDATION 5:** There is no basis for providing PHP with a priority interruptibility credit,
7 given (a) PHP is rarely if ever interruptible in practice under the IR, and (b) the priority interruption
8 adds nothing to the system in terms of extra resources, in exchange for the added credit provided
9 to PHP.

10 **3.4 Issues Regarding Transparency and Reporting**

11 The DR mechanism is new and complex. The benefits of the ELID can only be understood with a detailed
12 comparison of a hypothetical CBL load, as compared to actual PHP load, with the variance applied to an
13 hourly time-step marginal cost profile for the system.

14 Despite this inherent complexity, NSP is proposing a material reduction in both the regulatory oversight of
15 the tariff mechanisms, and the reporting on ELID/DR calculations. Neither is appropriate.

16 In respect of regulatory oversight of the mechanism for control and dispatchability, NSP is proposing that
17 the Operating Procedures for ELID not be subject to approval of the Board, as follows:³⁴

18 Consistent with the ELIADC Tariff, PHP operations under the DR will be governed by
19 Operating Procedures developed between NS Power, the System Operator, and PHP
20 (referred to under the ELIADC as Active Demand Control Energy Supply Protocol).
21 However, unlike the ELIADC Tariff, the benefits/costs of compliance/non-compliance with
22 the Operating Procedures will flow fully to PHP dependent primarily on PHP operational
23 priorities. As a result, the Operating Procedures are not included as part of the ELID Tariff
24 and not proposed to be subject to NSEB approval.

25 It is understandable that the Operating Procedures may still be under development, pending approval of
26 the specific tariff form as part of the current process. However, as part of an overall Tariff structure that
27 presumes a degree of benefits that will be paid for by regulated bundled service customers, it would appear
28 appropriate that the Board have direct approval oversight of the documentation and mechanics. Specifically,
29 core aspects of the tariff design that are of importance to the value balance, such as ensuring NSP has

³⁴ Matter M12661, Exhibit N-1, pdf page 11 of 50.

1 sufficiently enforceable control over PHP loads at acute system constraints as a fundamental premise for
2 granting PHP DR financial benefits, require implementation through this mechanism.

3 On the issue of reporting, the proposed ELID tariff only codifies reporting on the DR value and the annual
4 credit to occur annually, "no later than 60 days after the end of a tariff year."³⁵ NSP makes no commitment
5 to more frequent reporting or review, and does not seek approval of any such process to produce estimates
6 or calculations. NSP does note:³⁶

7 Monthly, quarterly, and annual reporting will depend on NSEB direction in this proceeding.
8 NS Power will work with Fuel Adjustment Mechanism (FAM) Small Working Group (SWG)
9 to develop an informative reporting process once the details of the approved ELID Tariff
10 and NSEB directives are known.

11 To ensure clarity for all parties, as part of the current approvals process the Board should require that NSP
12 provide the noted reporting, at least quarterly, and include in the reporting estimates of the DR value for
13 the full year, based on year-to-date results.

14 **RECOMMENDATION 6:** The Board should ensure that the Operating Procedures are specifically
15 noted as a matter for Board approval. Further the Board should clarify that reporting on the DR
16 status, including estimates of the annual DR to be funded by ATL customers, is provided at least
17 quarterly by NSP.

18 **4.0 ADDITIONAL PROPOSALS FROM THE EVIDENCE OF PHP**

19 PHP has submitted their own proposals for the ELID tariff which vary from the structure and principles
20 espoused by NSP.

21 The basic outline of the ELID is accepted by PHP, but with the following changes:

- 22 1) While NSP submitted that the PHP load should remain as per the GRA load forecast (810.5 GW.h
23 in 2026), PHP proposes to update this value reflecting their latest load forecast, to 774 GW.h per
24 year, before wind SEA, and further reduced by the forecast wind SEA of 154.61 GW.h.³⁷
- 25 2) PHP and their consultants propose that the PHP peak load for COS study purposes be fixed at 8
26 MW, with no further interruptible or firm load being included in the PHP rate calculation.
27 Alternatively, PHP proposes that the interruptible load be set at 57 MW, and that the credit provided

³⁵ Matter M12661, Exhibit N-1, pdf page 27 of 50.

³⁶ Matter M12661, Exhibit N-6, pdf page 1465 of 1474.

³⁷ Matter M12661, Exhibit N-3, pdf page 11 of 14.

1 to PHP be far higher than the Large Industrial credit, to a total of \$13.107/kVA (the full value of a
2 peaker unit, without any adjustment for availability at peak times).³⁸

3 3) PHP proposes to set the rate recovery at 100% of costs, rather than the proposal by NSP to match
4 the revenue:cost ratios that have been applied in the GRA to other non-residential classes (104.4%
5 revenue:cost).³⁹

6 4) PHP also apparently suggests some form of ancillary services credit be applied, though no specifics
7 have been proposed.⁴⁰

8 In respect of #1 – the update to loads – it is acknowledged that rates are typically set based on the latest
9 available load forecast. However, with the recently completed GRA, the COS has already been prepared
10 based on a recent load forecast that was adjudicated as part of Matter M12451. PHP has now indicated
11 that the projected usage for 2026 and 2027 is 774,000 MWh each year and the offsetting SEA is 154,610
12 MWh for 2026, and 507,400 MWh for 2027. This compares to 810 GW.h in the GRA forecast.

13 The update to the COS for the new loads has been quantified in response to information requests.
14 Specifically, the impact on other customers is 0.2% of costs, or less for 2026, and 0.1% or less for 2027.⁴¹
15 In a COS context, where +/- 5% ranges are typically applied as being reasonable, this would not be
16 considered material.

17 For PHP, the appropriate test of materiality is whether there is a net change in the average energy unit
18 cost. Under the updated loads for 2026, the PHP average unit cost declines slightly under the updated load
19 (0.07 cents/kW.h)⁴² which, at the updated load saves PHP approximately \$425,000 annually. However, the
20 cost of capacity for PHP goes up due to the change, by \$233,000, for a net impact (at a consistent load)
21 of less than \$200,000 on a total billed amount of over \$80 million/year. This net impact will be further
22 reduced at the demand levels proposed above (120 MW, rather than 65 MW) so the net effect appears to
23 be *de minimus*.

24 As such, there does not appear to be any material effects on the COS from updating the loads as proposed
25 by PHP.

³⁸ Matter M12661, Exhibit N-2, pdf page 4-5 of 34.

³⁹ Matter M12661, Exhibit N-2, pdf page 5 of 34.

⁴⁰ Matter M12661, Exhibit N-3, pdf page 14 of 14.

⁴¹ Matter M12661, Exhibit N-6, pdf page 19 of 1474.

⁴² Matter M12661, Exhibit N-6. The average energy cost for PHP in 2026 declines from 8.94 cents/kW.h to 8.87 cents/kW.h due to updating PHP loads (pdf pages 118 and 697). On an updated net load projection of 606.7 GW.h, this reduces PHP's energy costs by \$425,000. However, at the same time, the demand cost goes up from \$9.287 million to \$9.520 million, an increase of \$233,000. Similar calculations for 2027 (based on pdf pages 220 and 791) show PHP's projected energy cost would increase by 0.01 cents/kW.h, from 8.57 cents/kW.h to 8.58 cents/kW.h at the lower load, which would increase PHP's costs by \$20,500 on a net load of 205.1 GW.h, while demand costs would increase from \$12.009 million per year to \$12.065 million per year, an increase of \$56,000, due to updating loads.

1 In respect of PHP proposal #2 – adjusting the PHP peak load to 8 MW – the proposal is not appropriate.
2 As noted earlier in this evidence, PHP’s ATL profile in the COS (i.e., before application of the DR) should be
3 based on the full CBL, which suggests a higher load than proposed by NSP of (i.e., 120 MW, not 65 MW or
4 8 MW). NSP also clearly rebuts this proposal in response to IR CA-9(b), which notes that at 8 MW, PHP is
5 not a viable commercial operation, and would avoid paying for basically any transmission or generation
6 capacity, despite receiving material annual service requiring delivery of up to “19 times the 8 MW figure”.⁴³

7 Regarding PHP proposal #3, seeking changes to the proposed Revenue-to-Cost Ratios, there is no basis to
8 exclude PHP from the overall GRA adoption of ratios above 100% for non-residential customers. This part
9 of the rate design has been included in the NSP GRA negotiated settlement, and included in the Matter
10 M12451 compliance filing. This rate design aspect is also within the Board’s normal 95-105 band.⁴⁴ As such
11 NSP’s proposals are appropriate.

12 Finally, for ancillary services – proposal #4 – PHP bases their claim regarding providing ancillary services
13 using the example of having dropped load in the past in response to system disturbances, such as a
14 Maritime Link interruption on February 13, 2026. PHP indicates they are not compensated for this service,
15 nor do they believe it part of the ADC (and future DR).⁴⁵ NSP has now fully rebutted this claim, in response
16 to Synapse IR-27(c), clarifying that in fact the revision to PHP loads on February 13, 2026 was a “schedule
17 change” which is not only contemplated, but expressly permitted by the ADC/DR.⁴⁶ Consequently, there is
18 no basis for PHP to claim additional rights to compensation or new mechanisms beyond the DR.

19 **RECOMMENDATION 7:** The Board should not adopt the proposals from PHP to alter the rate as
20 proposed by NSP. This includes adjusting the PHP peak load to 8 MW in the COS study, adjusting
21 the PHP Revenue-to-Cost ratio to 100%, and providing PHP with added value related to ancillary
22 services for which it is already compensated via the DR.

⁴³ Matter M12661, Exhibit N-5, pdf page 204 of 206.

⁴⁴ Matter M12451, Exhibit N-3, pdf page 91 of 99.

⁴⁵ Matter M12661, Exhibit N-3, pdf page 14 of 14.

⁴⁶ Matter M12661, Exhibit N-10, pdf page 75-76 of 306.

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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 the PEI Federation of Agriculture (2023-2025): 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 (2024-2025): Provide analysis regarding net salvage regulatory account options.

For the Office of the Utilities Consumer Advocate of Alberta (2024-present; previous involvement 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) (2025): Act as facilitator for distribution rate application for Welland Hydro.

For J. D. Irving Ltd. (2022-2024); 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 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 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 Req't, 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 Settlement
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 Settlement
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	Kepphills 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 year 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	Muskat 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	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
Maritime Electric	UE22503 Rate Design	Analysis, Preparation of Intervenor Evidence	Prince Edward Island Regulatory and Appeals Commission (IRAC)	PEI Federation of Agriculture	2024-2025	Yes
Nova Scotia Power	M11475 Cost of Service Study	Analysis, Support of Intervenor position	Nova Scotia Energy Board (NSEB)	Industrial Group (IG)	2024-2026	No
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
Efficiency One	M12228 Benefit-Cost Test	Analysis, Preparation of Intervenor Evidence	NSEB	Industrial Group (IG)	2025	Yes
Nova Scotia Power	2025 GRA	Analysis, Support of Intervenor position	NSEB	Industrial Group (IG)	2025-2026	No
AltaLink Management Ltd.	2026-27 General Tariff Application	Analysis, Support of Consumer Advocate in Negotiation Process, Preparation of Intervenor Evidence on Depreciation .	AUC	UCA	2025-2026	Yes
Manitoba Hydro	2025-26 to 2027-28 GRA	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2025-2026	Yes
Manitoba Hydro	2026-2035 Integrated Resource Plan	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2026	TBD
ATCO Electric Transmission	2026-2027 GTA Depreciation	Analysis, Support of Consumer Advocate in Negotiation Process, Preparation of Intervenor Evidence on Depreciation .	AUC	UCA	2026	TBD
Eastward Energy	2026 General Rate Application	Analysis, Preparation of Intervenor Evidence	NSEB	Michelin/Dalhousie	2026	TBD