

Extra Large Industrial Active Demand Control (ELIADC) Tariff
2025 Annual Report (NSEB M12768)
NSPI Responses to IG Information Requests

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Request IR-1:

Reference: 2025 Annual Report, Exhibit N-1, p. 3/9, Table 1

- (a) Please explain how the level of benefit reported for 2025 compares to the range of benefits anticipated at the time the ELIADC tariff was approved.**
- (b) Of the \$4.4 million benefit, what amount is associated with recovery of fixed costs, and what, if any, is applied to the FAM?**
- (c) Please explain the principal drivers of the positive ADC load shifting differential in 2025 after four years of negative differentials, distinguishing among:**
- (i) Commodity price effects;**
 - (ii) Changes in PHP load levels or load profile;**
 - (iii) System conditions and dispatch optimization;**
 - (iv) Tariff administration or timing effects; and**
 - (v) Any other effects.**
- (d) Does NSPI expect the ADC differential to remain positive under continued operation of the existing ELIADC tariff in 2026? Please explain and provide the forecasted benefit (if any).**

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1 Response IR-1:
2

3 (a) The Company's 2019 ELIADC Tariff Application (M09420) forecast annual benefits to
4 other customers ranging from \$6 to \$13 million over the initial term (2020 to 2023), with
5 an average of \$10 million per year based on an assumed annual PHP load at approximately
6 1 TWh (1,000 GWh). The 2025 actual benefit (\$4.4 million) falls below this forecast range,
7 as does the actual 2025 PHP load (691 GWh or 63 percent of the forecast load in 2019).
8 On a per-MWh basis, the 2025 benefit (\$6.37 per MWh) represents approximately 69
9 percent of the 2019 forecast benefit of \$9.23 per MWh.
10

11 The 2019 forecast benefit did not anticipate the fuel price volatility experienced from 2021-
12 2024 due to geopolitical events, which resulted in actual costs that significantly exceeded
13 the forecast CBL Energy Charge. The \$4.4 million benefit realized in 2025 also represents
14 the second-highest annual benefit achieved over the six-year operating history, a 30 percent
15 increase relative to the 2021-2024 average of \$3.4 million, and 60 percent of the 2020 result
16 (\$7.3 million, which itself exceeded the first-year forecast of \$6 million by 21 percent),
17 suggesting improved alignment with forecast performance as fuel markets have largely
18 moderated by comparison.
19

20 (b) Please refer to the table on page 1 of the Report Attachment – specifically the totals in the
21 'Fixed Cost Recovery' columns under the 'CBL Energy Charge' and 'CBL Adder' headers.
22 Of the \$4.4 million benefit, approximately \$2.8 million is associated with fixed cost
23 recovery.¹
24

25 (c)
26 (i) Commodity price effects: the main factor for this year's positive ADC load shifting
27 differential, when compared to previous years, was that actual fuel and purchased

¹ \$4 per MWh multiplied by the 690,763 MWh of 'Total Energy Delivered MWh)' as reported on page 1 of the Report Attachment.

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1 power costs were, on average, similar to the pricing in the forecasts used in setting
2 the 2025 CBL Energy Charge.

3
4 (ii) Changes in PHP load levels or load profile: in 2025 and prior years, PHP has
5 amended its load profile to reduce costs. The Company does not believe differences
6 in this regard between 2025 and prior years were a material contributor to the
7 positive ADC.

8
9 (iii) System conditions and dispatch optimization: SO₂ Certificate of Variance resulted
10 in higher energy production from coal plants as compared to recent years; however,
11 while the higher coal output contributed to the overall lower cost of energy
12 production, NS Power does not believe it contributed to positive ADC, as compared
13 to previous years.

14
15 (iv) Tariff administration or timing effects: Tariff administration was affected by the
16 lack of established digital tools, namely the loss of PortOps software functionality
17 post cyber incident; however, NS Power's experience with the dispatch of PHP,
18 PHP's collaboration in the post cyber incident reality, and supplemental use of
19 digital tools such as PLEXOS, lead to effective PHP load dispatch and subsequent
20 realization of ADC benefit.

21
22 (v) Any other effects: not to NS Power's knowledge.

23
24 (d) Under the current Tariff construct, if there are minimal increases in commodity prices in
25 2026, as compared to the forecast, it is expected the calculation will yield a positive ADC
26 load shifting differential. NS Power notes that the proposed ELID Tariff, which remains an
27 open Matter before the Board, considers price-normalized assessment of load shifting
28 benefit, which isolates the load shifting benefit from being masked by commodity price

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1 movement, consistent with NS Power's internal calculations of load shifting benefits of the
2 ELIADC Tariff.

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Request IR-2:

Please quantify the impact of applying the 2024 ELIADC energy charge for January 2025 on:

(a) The monthly ADC differential for January 2025; and

(b) The total 2025 benefit to other customers.

Response IR-2:

(a) As described on page two (2) of the Report, and in accordance with the Board Interim Order in the 2024 Annually Adjusted Rate Application (M11989), the 2025 ELIADC Energy Charge came into effect on February 1, 2025.

Please also refer to page two (2) of the Report Attachment. The monthly ADC differential for January 2025 was \$2.6 million higher than the amount billed to PHP. In January 2025, PHP was billed the forecasted CBL Energy Charge (\$101.65 per MWh) compared with their actual CBL Energy Charge (\$152.63 per MWh). If, in January 2025, PHP were billed the 2025 ELIADC Energy Charge (\$96.00 per MWh) rather than the 2024 ELIADC Energy Charge (\$101.65 per MWh), the ADC differential would be \$2.9M.

(b) The total 2025 benefit to customers would have been \$0.9 million, as compared to the \$1.1 million provided on page two (2) of the Report Attachment.

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Request IR-3:

(a) Please explain, step-by-step what was done by each of the Energy Marketing Team and PHP as they “adapted and worked collaboratively” following the cyber breach. In your explanation, specify when this began and when it concluded.

(b) Please detail any incremental costs to accomplish this (or decrease in costs).

(c) Please provide a clean copy of the existing ELIADC Protocols and redline of any revisions to the ELIADC Protocols which applied during this period.

Response IR-3:

(a) Following the April 25, 2025 cyber incident, the NS Power Energy & Risk Management group (NS Power E&RM) used historic PortOps and PLEXOS trends to create optimized hourly load schedules for PHP and built a day-ahead strategy, in conjunction with the Nova Scotia Power System Operator (NSPSO) and PHP. Historically, the PortOps and PLEXOS models consistently scheduled PHP at high loads overnight in the off-peak hours and reduced PHP load during the on-peak hours.

On May 1, 2025, PHP sent its estimated hourly load forecast. The PHP load forecast trend aligned with the historic schedule (high loads overnight in the off-peak hours and reduced loads during the on-peak hours), with weekends and daytime wind events providing the opportunity for increased PHP load. Estimated PHP schedules were reviewed by day-ahead NS Power E&RM for reasonability. Verbal and/or email responses would follow. A manual day-ahead schedule was sent to the NSPSO. The NSPSO suspended the Open Access Transmission Tariff Standards of Conduct providing an opportunity for visibility to operational data and increased discussion regarding dispatch strategies. The NSPSO would work with PHP real-time and use the day-ahead schedule as a dispatch guide. As

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1 per standard practice, system wind and load adjustments would be considered and managed
2 in real-time by the NSPSO. The production of day-ahead schedules resumed on May 26,
3 2025 and real-time schedules resumed on August 5, 2025.

4
5 (b) There were no incremental costs associated with this process. The process utilized the
6 existing PLEXOS model, adapted for use in day-ahead planning.

7
8 (c) Please refer to Attachment 1.

Part A – Definitions

ADC: Active Demand Control.

ADC Operating Procedure: Procedure document maintained by Nova Scotia Power System Operator (NSPSO) that describes the operation and usage of ADC for the NSPSO for Current Hour, Operating Hour 1 & Operating Hour 2.

CBL: Customer Baseline Load.

CBL & ADC Benefit Calculation: Process maintained by Nova Scotia Power (NS Power) to calculate the CBL Energy Charge, forecasted ADC benefit and actual ADC benefit.

Current Hour: The current hour of operation, which is only dispatchable by NSPSO.

Dispatchable Hours: All hours beyond Hour 2, as described (hour 3, 4 and beyond) in Section 4.3.10 of the NS Market Rules that are open for redispatch by NS Power.

Excess Energy: Generation which is in excess of the needs of the electric system and which cannot be stored.

Force Majeure: Any event or circumstance or combination of events or circumstances (including major equipment failure) that materially and adversely affects either party in the performance of its obligations in accordance with the terms of this Protocol, but only if and to the extent such events and circumstances are not within the affected party's reasonable control, and which the party claiming Force Majeure could not have prevented through reasonable skill and care.

Hour 1: The next hour, as described (hour 1) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

Hour 2: The next hour +1, as described (hour 2) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

Intra-Day Demand Schedule (ADC Schedule 4): An hourly demand profile that includes all Dispatchable Hours for a consecutive 24-hour duration. This will be provided by NS Power as a forecast to Port Hawkesbury Paper LP (PHP) and NSPSO for the upcoming period. NSPSO will confirm the schedule and only change dispatch if required for a change in system conditions.

Monthly Demand Schedule (ADC Schedule 1): A monthly, indicative, demand profile that includes a maximum and minimum demand profile for all months of the year, or all remaining months of the year if a system rerun is required. These forecasts will be performed annually and updated as required

by NS Power. Refer to Part B. The results of these runs will be presented and shared with PHP as ADC Schedule 1.

NS Market Rules: Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

NS OATT: Nova Scotia Power Incorporated Open Access Transmission Tariff including the Standards of Conduct (Attachment E).

NS Power: Nova Scotia Power Groups – Fuels, Energy and Risk Management (FERM), Portfolio Optimization, Customer Solutions and any other non-System Operator Nova Scotia Power function.

NSPSO: Any Nova Scotia Power System Operator function.

Operating Mode Characteristics Schedule: The schedule referenced in Part D of this Protocol.

PHP: Port Hawkesbury Paper LP.

Seven Day Demand Schedule (ADC Schedule 3): An hourly demand profile produced and co-optimized as part of the system by NS Power each business day. The Seven Day Demand Schedule includes all Dispatchable Hours, starting 00:00 for the upcoming business day, for a 168-hour duration.

Tariff: The Extra Large Industrial Active Demand Control Tariff.

Weekly Demand Schedule (ADC Schedule 2): An annual, indicative, demand profile that includes a maximum and minimum demand profile for each week of the year or all remaining weeks of the year, if a system rerun is required. This will inform the development of the Seven Day Demand Schedule. These forecasts will be performed annually and updated as required by NS Power.

Part B – Protocol Forecasting and Operation

- (1) Annually, no later than the seventh business day of November, NS Power will forecast the Monthly Demand Schedule, Weekly Demand Schedule, and monthly and weekly limits based on PHP's demand forecast for the upcoming year (January 1 to December 31). The results of these forecasts will be published to PHP and NSPSO in ADC Schedules 1 & 2. As and when required during the year, NS Power will reforecast the Monthly Demand Schedule and Weekly Demand Schedule and update ADC Schedules 1 & 2. The values in ADC Schedules 1 & 2 will bound the daily forecast runs used to create the Seven Day and Intra Day Demand Schedules.
- (2) On a daily basis (non-statutory holiday weekdays), NS Power will provide PHP and NSPSO with a Seven Day Demand Schedule that is optimized as part of the NS Power system day-ahead planning process. PHP's demand will be co-optimized as part of the full NS Power portfolio. As part of this co-optimization:

- (a) With respect to forecast PHP annual capital shutdowns, PHP will provide a minimum of one month's advance notice of the timing and duration of the shutdowns; and
 - (b) With respect to forecast PHP regular maintenance shutdowns, PHP will provide a minimum of seven days advance notice of the timing and duration of the shutdowns.
- (3) From time to time, a request may be made to PHP to adjust their daily demand from the Seven Day Demand Schedule in anticipation of significant events. An example of this would be a weather event that is forecasted. Such requests must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.
- (4) Intra-Day, no later than the start of Hour 1, NS Power will provide PHP and NSPSO with an updated Intra-Day Demand Schedule when a dispatch change is required. This request will supersede the previously submitted requests.
- (5) If, during the Current Hour, Hour 1 and/or Hour 2, system conditions change unexpectedly such that they have a material impact (positive or negative) on system costs, NSPSO will contact PHP with a schedule change (an increase or reduction in demand) provided such changes fall within: the agreed Operating Mode Characteristics Schedule, the final communicated PHP shutdowns, and the ADC Operating Procedure. Otherwise the most recent schedule submitted by NS Power will be set as the hourly demand. This will represent the final demand schedule with any deviations tracked as a schedule variance.
- (6) As noted in the Tariff, if, during the current year, NS Power determines that there are significant adverse differences between the CBL Energy Charge (as defined in the Tariff) and the incremental costs of service, NS Power, with approval of the NSUARB, can adjust the rate on a prospective basis as provided for in the Tariff. In such circumstances, NS Power shall also update and communicate its expected forecast of ADC benefit for the remainder of the year.
- (7) NS Power, NSPSO and PHP will exchange the following information on a confidential basis through the methods described below:
 - 7.1. Intra-Day Demand Schedule (ADC Schedule 4) – NS Power;
 - 7.2. Seven Day Demand Schedule (ADC Schedule 3) – NS Power;
 - 7.3. Weekly Demand Schedule (ADC Schedule 2) – NS Power;
 - 7.4. Monthly Demand Schedule (ADC Schedule 1) – NS Power;
 - 7.5. Nova Scotia's Base load forecast – NSPSO;
 - 7.6. Nova Scotia's aggregate wind forecast – NSPSO;
 - 7.7. PHP pulp storage levels – PHP; and

7.8. PHP discrete line operation (i.e. what lines are in and out of service in a period) – PHP.

NS Power and PHP agree that, in order to (1) assist PHP to efficiently respond to any dispatch schedule changes that may be requested by NS Power and/or NSPSO in a manner that benefits the NS Power electric system, and (2) enhance collaboration between the parties when responding to unplanned system changes, NS Power will provide PHP with access to certain system information. On an automated basis, NS Power will provide PHP with information in respect of its system demand and the aggregation of generation types (specifically coal, gas, oil, combustion turbines, imports and hydro) as a snapshot of the current system condition. PHP agrees that such information is to be used exclusively for the foregoing purposes. During any period in which this data is unavailable due to technical issues, PHP will refer to the <https://www.nspower.ca/en/home/about-us/todayspower.asp> until NS Power is able to re-establish the provision of this data on a timeline that is reasonable, given NS Power's other business priorities. Any use of the data for purposes beyond operational preparedness can result in the suspension of the data sharing.

- (8) On an annual basis, NS Power will calculate the actual ADC benefit consistent with the CBL & ADC Benefit Calculation.

Part C – Conditions

- (9) Subject only to reasons of health, safety, environmental, system reliability, and Force Majeure events, PHP must not deviate from the NS Power/NSPSO final demand schedule. NS Power/NSPSO must comply with the weekly demand requirements as determined by the Weekly Demand Schedule. In the situation where the Weekly Demand Schedule requirements are not complied with, NSP/NSPSO will work collaboratively with PHP to address the discrepancy.
- (10) Following any health, safety, environmental, system reliability, or Force Majeure event, PHP and NS Power will use commercially reasonable efforts to restore their applicable operation to normal as soon as possible and without undue delay. In such circumstances, PHP will advise NS Power as soon as possible of any change in availability of PHP's operating modes to allow NS Power to adjust its dispatch schedules accordingly. PHP and NS Power will maintain, as a minimum, hourly contact with each other in the hours following Force Majeure events to keep each other aware of the other's status.
- (11) In the case of NS Power or PHP's inability to follow the dispatch plan that triggers one of the circumstances as set out in Appendix 1, the timing, magnitude, and reason for the deviation will be tracked and noted by NS Power/NSPSO. This Appendix may be updated by agreement between NS Power and PHP if other circumstances arise that require variances from the scheduled dispatch to be tracked. Updates to this Appendix will be filed with the NSUARB.

- (12) Subject to available generation or load, as the case may be, efforts will be made to reconcile variances in a timely manner, including by NS Power and PHP mutually agreeing to deviate from the previously agreed Operating Mode Characteristics Schedule, with the goal of achieving similar system costs and service to the Mill as would have been achieved if the original dispatch had been followed.
- (13) The overall impact on system costs (if any) for the tracked deviations will be initially estimated on a quarterly basis, and assessed at the end of the year by NS Power. If a cost is determined, the ADC credit payment to PHP will be adjusted accordingly.
- (14) PHP, NS Power and NSPSO shall maintain a scheduling and/or operations team available to each other on a continuous 24 hour, 7 days a week basis.
- (15) PHP's scheduling and operations team shall be empowered with the authority to acknowledge and adjust PHP's demand on behalf of PHP for the supplied Demand Schedule.
- (16) This Protocol does not supersede any requirement or obligation as defined in both the NS OATT (including the Standards of Conduct) and NS Market Rules. If a change to either NS OATT and/or NS Market Rules occurs, this Protocol will be updated to reflect any changes, if applicable.
- (17) For the purposes of planning, PHP will provide NS Power and NSPSO with its expected annual capital outage timing. This data will be provided in a timely manner, to be included in the NS Power/NSPSO annual planning process. The parties will work collaboratively to co-optimize the timing of PHP outages to provide the best fit for the system while respecting PHP's limitations and requirements consistent with Part B, section 2.
- (18) All energy dispatch decisions as they relate to system demand will be performed at the sole discretion of NS Power and/or NSPSO. This includes, but is not limited to, generation dispatch levels, unit commitments, outage planning and/or import/export energy.
- (19) The dispatch of PHP demand level will be performed by NS Power and/or NSPSO and must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.

Part D – Operating Mode Characteristics Schedule

For the purpose of planning, dispatch and forecasting, PHP's loading levels will be separated into 9 distinctive operating modes. Only one mode will be able to operate at any given time.

The Operating Mode Characteristics Schedule will include (i) maximum and minimum, up and down time of each operating level, (ii) mill ramp rates, (iii) mill outages planning, (iv) pulp storage levels, and (v) individual line operating modes. This Schedule will be used in the preparation of the demand schedules, the calculation of the CBL incremental cost and the overall ADC benefit achieved as a result of the dispatch of PHP's load. NS Power and NSPSO will be required to dispatch PHP's load consistent with the Operating Mode Characteristics Schedule, including the maximum and minimum limits in ADC Schedules 1 & 2.

This schedule will also contain the maximum and minimum amounts of Annual, Monthly and Weekly energy requirements.

The Operating Mode Characteristics Schedule will be initially developed by PHP in consultation with NS Power and can be changed from time to time by agreement of PHP and NS Power.

Appendix 1

Circumstances in which Variances from Scheduled Dispatch Will Be Tracked

The variance from the scheduled dispatch results in:

- A change in NS Power unit commitment(s)
- A need for NS Power to rebalance a fuel position
- The redispatching of generation from Wreck Cove
- A reduction in the value of an NS Power export or import opportunity
- A condition of Excess Energy
- NS Power/NSPSO is forced to dispatch PHP outside the Operating Mode Characteristics Schedule

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Request IR-4:

Reference: 2025 Annual Report, Exhibit N-1, p. 2/9 and Benefit Breakdown, p. 2/3

PHP will be billed the cost to serve above the amount that was collected on a monthly basis, in addition to the \$4/MWh and other applicable fixed costs, to ensure compliance with the Tariff. NS Power will include the required adjustment of \$149,304, taking into account all of PHP's payments during the year, on PHP's upcoming bill.

(a) This figure (\$149,304) is found in the final column of the Benefit Breakdown. Please explain the column heading "Adjusted PHP Benefit", compare to the column, "PHP Benefit (25%)" and explain the monthly adjustments made.

(b) Has this amount been billed and paid?

(c) Does this amount carry interest? If so, who pays?

Response IR-4:

(a) With reference to the table on page two (2) of the Report Attachment (as abridged below).

(A)	(B)	(C)	(D)	(E)	(F)	(G)
<i>ADC Differential</i>	<i>NSPI Benefit (75%)</i>	<i>PHP Benefit (25%)</i>	<i>Off Schedule Charge</i>	<i>75% of Off Schedule Charge</i>	<i>Adjusted NSPI Benefit</i>	<i>Adjusted PHP Benefit</i>
\$ (2,610,587)	\$ (1,957,941)	\$ (652,647)	\$ -	\$ -	\$ (1,957,941)	\$ (652,647)
\$ (3,254,988)	\$ (2,441,241)	\$ (813,747)	\$ -	\$ -	\$ (2,441,241)	\$ (813,747)
\$ 62,181	\$ 46,636	\$ 15,545	\$ -	\$ -	\$ 46,636	\$ 15,545
\$ 360,420	\$ 270,315	\$ 90,105	\$ -	\$ -	\$ 270,315	\$ 90,105
\$ 3,395,455	\$ 2,546,591	\$ 848,864	\$ 9,171	\$ 6,879	\$ 2,553,470	\$ 841,985
\$ 657,833	\$ 493,375	\$ 164,458	\$ -	\$ -	\$ 493,375	\$ 164,458
\$ 180,235	\$ 135,177	\$ 45,059	\$ 8,598	\$ 6,449	\$ 141,625	\$ 38,610
\$ 1,385,785	\$ 1,039,339	\$ 346,446	\$ 25,603	\$ 19,202	\$ 1,058,541	\$ 327,244
\$ 1,222,214	\$ 916,661	\$ 305,554	\$ -	\$ -	\$ 916,661	\$ 305,554
\$ 1,688,101	\$ 1,266,076	\$ 422,025	\$ 11,038	\$ 8,278	\$ 1,274,354	\$ 413,747
\$ 742,126	\$ 556,594	\$ 185,531	\$ 262,483	\$ 196,862	\$ 753,457	\$ (11,331)
\$ (2,306,165)	\$ (1,729,623)	\$ (576,541)	\$ 389,716	\$ 292,287	\$ (1,437,336)	\$ (868,828)
\$ 1,522,611	\$ 1,141,958	\$ 380,653	\$ 706,609	\$ 529,957	\$ 1,671,915	\$ (149,304)

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1 • (A) is the ADC differential before the addition of fixed cost recovery, as referenced
2 in the Company's response to IG IR-1 part (b), and prior to the adjustments for Off-
3 schedule Charges.

4
5 • (B) is 75 percent of (A).
6

7 • (C) is 25 percent of (A).
8

9 • (D) is the Off-schedule Charges associated with the 95 hours in which PHP chose
10 to deviate from the submitted schedule (Code 5, "PDN"), as described on page 4 of
11 the Report.

12
13 • (E) is 75 percent of (D).
14

15 • (F) is the sum of (B) and (D) and reflects the ADC differential to other customers.
16

17 • (G) is (C) minus (E) – resulting in the (\$149,304) figure in (G) which represents
18 the ADC differential to PHP.
19

20 Note that the monthly breakdown of these adjustments are accrual-based accounting
21 treatments and do not represent monthly calculations conducted throughout the year as the
22 ADC differential is determined on an annualized basis, once actual costs and PHP dispatch
23 are known.
24

25 (b) No, as provided on page two (2) of the Report, these amounts are billed to PHP after the
26 Annual ELIADC Report is accepted by the Board.
27

28 (c) No.

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1 **Request IR-5:**

2
3 **Reference: 2025 Annual Report, Exhibit N-1, p. 3/9, Load Variations**

4
5 **PHP's initial 2025 forecast totalled 811 GWh. There were revisions to PHP's**
6 **load forecast through the year, with a final actual demand requirement of 891**
7 **GWh.**

8
9 **(a) Please confirm that the December 2025 FAM monthly report, M-1, shows a full year**
10 **forecast of 813.3 GWh (and in each prior monthly report). Please reconcile this figure**
11 **with 811 GWh in N-1.**

12
13 **(b) On what date was PHP's initial 2025 load forecast of 811 GWh (or 813.3 GWh)**
14 **received by NSPI?**

15
16 **(c) Is this in accordance with a standard schedule? Please explain.**

17
18 **(d) Please identify each revision to the PHP load forecast during 2025, including the**
19 **month of revision and the revised annual forecast.**

20
21 **(e) What steps were taken by NSPI upon receipt of PHP's revised load forecast?**

22
23 **(f) Please provide a copy of the process and protocol for load forecast revisions. If there**
24 **is no written protocol, please explain what is done in practice.**

25
26 **(g) Please explain how the divergence between the forecast and actual load affected:**

27
28 **(i) Dispatch optimization;**

29
30 **(ii) The calculation of the CBL energy charge; and**

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1 **(iii) ADC load shifting benefits.**

2
3 **(h) Please compare the magnitude and causes of forecast error in 2025 with those in 2024**
4 **and prior years.**

5
6 Response IR-5:

7
8 Preamble: The reference provided in this IR incorrectly quoted “a final actual demand
9 requirement of 891 GWh.” As provided at page 3 of the Report, the final actual
10 demand requirement was 691 GWh.

11
12 (a-b) These amounts are from two separate forecasts. The 813.3 GWh reported in the December
13 2025 Monthly FAM Report used assumptions from NS Power’s 2025 internal budget
14 prepared in August 2024 and was provided to NS Power by PHP on September 13, 2023.
15 The 811 GWh figure for the 2025 Annually Adjusted Rates (AAR) Application (M12551)
16 was from the load forecast that PHP provided NS Power on September 26, 2024.

17
18 (c) The ELIADC Tariff process requires PHP to provide NS Power with a revised load forecast
19 prior to the end of September of the preceding year.

20
21 (d) Please refer to Confidential Attachment 1 for the Energy Marketing work sheet which
22 includes PHP requested adjustments to the load schedule.

23
24 (e-f) Upon receipt, the revised monthly PHP load target is added to a file which NS Power
25 Energy Marketing uses to track the most current PHP forecast. If the load forecast revision
26 results in a requirement for more energy for PHP, NS Power discusses with PHP any
27 potential issues with serving higher PHP demand and the load shifting patterns required to
28 achieve the forecast demand. New monthly targets are decomposed to weekly volumes in

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1 the day-ahead and real-time scheduling models. The weekly PHP load determines optimal
2 daily levels, which are shaped hourly according to system conditions and requirements.

3
4 (g)

5 (i) The divergence between 2025 forecast and actual load had little impact on real-
6 time dispatch optimization. Despite the increased volume of actual energy
7 delivered over the initial 2025 forecast, PHP continued to be dispatched hourly in
8 an economically optimal manner using the optimization processes available.

9
10 (ii) The CBL Energy Charge is based on a forecast and set during the AAR process and
11 was not revised during 2025. Since the forecast is set the year prior, many factors
12 change including, but not limited to, commodity pricing, CoV for SO₂ air emission
13 compliance, unit availability, and PHP's load requirements. These deviations and
14 others create variances from the forecast to actual costs at the time of dispatch.

15
16 (iii) Given that PHP's actual load was optimized over the course of 2025, if it were to
17 have run 120 GWh more over the course of the year as compared to its original
18 forecast load, on average, it would have been served by more expensive generation
19 and imports, and this would have decreased the ADC Load Shifting Differential.

20
21 (h) PHP's energy requirements are adjusted throughout the year for reasons including order
22 requirements and timing, NS Power system conditions, unit and capacity availability, and
23 commodity pricing. These factors mean that changes in PHP's energy requirements are not
24 necessarily attributed to forecast error but system and market conditions. It should be noted
25 that the CBL is set on a hypothetical, flat-load profile, meant to reflect a customer
26 indifferent to energy pricing or system conditions. This means that monthly energy
27 requirements and costs will not match actual dispatch, as the goal is to dispatch PHP as
28 economically as possible.

2025 ELIADC IG IR-5 Confidential Attachment 1 has been removed due to confidentiality.

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Request IR-6:

Reference: ELIADC Tariff Revenue Table p. 1/3 and 2025 Annual FAM Reporting

(a) Please reconcile the ELIADC revenue reported on A3 of the annual FAM report to:

(i) The CBL energy charge collected from PHP in 2025;

(ii) ADC and VOM adjustments relating to prior years;

(iii) The adjusted \$149,304 amount stated as owing from PHP.

(b) Please explain why 2024 ADC and VOM adjustments were recorded in 2025 and how this practice affects transparency and year-to-year comparability.

(c) Does NSPI expect similar inter-year adjustments to persist under the 2026 ELIADC tariff? Please explain

Response IR-6:

(a) Consistent with prior years, these amounts have been provided on Page 1 of the Report Attachment. Please also refer to M8 of the Monthly FAM Reports for the month-by-month reconciliation. As there are timing differences between when the Monthly December FAM, Annual FAM, and ELIADC Tariff Reports are finalized, adjustments are reported in subsequent Monthly or Annual Reports (as applicable). For example, the \$149,304 adjustment for 2025 ELIADC Tariff performance, is reported in the March 2026 Monthly FAM Report filed on April 21, 2026.

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- 1 (b) As described in part (a), the annual ELIADC Tariff results are not finalized until after filing
2 the December Monthly FAM Report as well as after the release NS Power's annual
3 financial statements. NS Power follows the US Generally Accepted Accounting Principles
4 (US GAAP), and the inclusion of the prior period adjustment follows US GAAP ASC 606
5 – Revenue from Contracts with Customers. These amounts for prior periods adjustments
6 are explicitly stated within FAM reporting and have explanatory footnotes for the
7 adjustments made.
8
- 9 (c) Yes, as described in parts (a) and (b), due to differences in timing between monthly and
10 annual reports, and NS Power adherence to US GAAP, which is accrual-based accounting,
11 the Company expects these inter-year adjustments will continue to occur.

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Request IR-7:

**Reference: Monthly FAM reports, M-1 (non-confidential) and M-8 (redacted) and
ELIADC Tariff Revenue Table, p. 1/3**

(a) Please extract and compile the ELIADC data from M-1 and M-8 in the FAM monthly reports in a table similar to the ELIADC Tariff Revenue table. Highlight any cells that differ from what was filed in this Annual report and reconcile and provide an explanation for each variance.

(b) Please explain the notations for accrual booked and accrual reversed (e.g. November monthly FAM report.)

Response IR-7:

(a) The Monthly FAM Report tab M-8 reconciles ELIADC Tariff amounts billed to PHP during each month to the amounts recorded on tab M1. Page 1 of the ELIADC Tariff Report Attachment serves this reconciliation purpose. The CBL Energy Charge date compiled in the Report Attachment is directly sourced from the FAM Monthly Reports. As described in IG IR-6, the requested reconciliation between monthly and annual reporting has already been completed and is reflected in the materials on the record in this, and the FAM Monthly, proceeding. The 2025 actual ELIADC Tariff recorded revenue of \$64.7 million is shown in the year-to-date amount on M1 of the December 2025 Monthly FAM Report, on line A3 of the 2025 Annual FAM Report, and is the starting point for the reconciliation presented on Page 1 of the Report Attachment. Accordingly, no variances exist between the monthly FAM reports and the Annual Report filing; the data sources are aligned.

(b) PHP is billed on a weekly basis, and billing periods do not align precisely with the calendar month. Accruals and accrual reversals are therefore recorded to ensure that revenues and

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1 expenses are recognized in the appropriate accounting period, in accordance with US
2 Generally Accepted Accounting Principles (US GAAP).

3
4 Using the November 2025 Monthly FAM Report as example, PHP receives weekly
5 invoices covering service periods from October 27 to November 23. The portion of the first
6 November invoice that relates to the October 27-31 service period was accrued as part of
7 October's financial and FAM reporting. Accordingly, that accrued amount is reversed in
8 November as an "accrual reversal" when the actual invoice is recorded.

9
10 Conversely, the portion of services provided from November 24-30 is not invoiced until
11 December. To ensure these amounts are recognized in the correct period (the month in
12 which service was provided), an accrual is recorded for November. This accrual is
13 subsequently reversed in December when the invoice is issued and recorded, thereby
14 avoiding double-counting and ensuring amounts are recorded in the correct accounting
15 period.

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REDACTED

Request IR-8:

Reference: 2025 Annual Report, Exhibit N-1, p. 5/9 – Schedule Deviations (Cause Code 5, “PDN”) and Off-schedule Details, p. 3/3

(a) Please describe in detail the methodology used to calculate the \$706,609 system cost attributed to PDN deviations in 2025, including modeling assumptions and treatment of avoided or incremental system costs.

(b) Does the \$706,609 figure represent a cost to customers (i.e. a harm caused by PHP's deviation from schedule) or a forgone benefit? Please explain.

(c) Is it accurate that regardless which Cause Code, FAM customers are assigned 75% of the costs (or benefits) and PHP is assigned 25%? Does this also apply when PHP chooses not to follow the assigned schedule?

(d) Please explain each of the column headings.

(e) Please explain the asterisked footnote, “*Off Schedule Charges are only included in billing with positive ADC value”.

(f) Please sum the three shaded columns and provide the total, unredacted.

Response IR-8:

(a) As it was in 2020, when PHP last had a positive ADC Load Shifting Benefit, in accordance with the ADC benefit calculation prescribed in the ELIADC tariff, the Off-Schedule Charge of \$706,609 was calculated as the sum of the following equations for every hour in which there was a Cause Code 5:

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REDACTED

- 1 • Hourly Off-Schedule Charge = (PortOps modeled cost to serve x PHP load) - (CBL
2 Energy Charge x PHP load)

3
4 (b) The Off-Schedule Charge is neither a cost to customers (as PHP pays for its incremental
5 cost to serve) nor a true foregone benefit. Similar to the ADC Load Shifting Differential,
6 it is a construct of the ELIADC Tariff, where the Off-Schedule Charge was designed as an
7 incentive for PHP to follow dispatch.

8
9 (c) No, the ADC Load Shifting Differential is not calculated as a product of the Cause Codes.
10 No, PHP's 75 percent of Cause Code 5 costs, as they were calculated in the Off-Schedule
11 Charge, were applied to Benefit to Other Customers, and comprise part of the \$4.4 million
12 for 2025 shown in Table 1 on page 3.

13
14 (d) The column headings are as follows:

- 15
16 • Date and HE – The date and the hour ended (HE) in which the Cause Code 5
17 occurred;
18 • Metered Load – PHP's load in that hour as measured by its NS Power meter;
19 • Expected Load – PHP's scheduled load in that hour;
20 • Off Schedule MW – The variance between Metered Load and Expected Load;
21 • Cause Code – The Cause Code's lettered abbreviation;
22 • Paid by PHP – [REDACTED];
23 • PHP Incurred Cost – [REDACTED]
24 [REDACTED]; and
25 • Cost to PHP – [REDACTED]
26 [REDACTED].

27
28 (e) As per the Active Demand Control Energy Supply Protocol, the Off-Schedule Charge is
29 applied against the ADC Credit (i.e. ADC Load Shifting Benefit or Differential) as an

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REDACTED

1 incentive for PHP to follow dispatch and retain its 25 percent share of the ADC Load
2 Shifting Differential. In 2021-2024, the ADC Load Shifting Differential was negative, and
3 therefore no Off-Schedule Charges were applied.

4

5 (f) Paid by PHP: \$642,700

6 PHP Incurred Cost: \$1,349,309

7 Cost to PHP: \$706,609

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Request IR-9:

(a) Please identify the specific dates in 2025 during which Cause Code tracking was incomplete, and confirm the Cause Codes affected.

(b) Please explain how NSPI assessed ELIADC performance and benefits during periods when Cause Code data were unavailable. Specifically address what assumptions were used and how they were determined.

(c) In noting that comparisons to other years “are difficult” please indicate how reliable NSPI’s year-over-year comparisons are.

(d) Is there a means to “normalize” the period when Cause Code tracking was unavailable? If so, please provide updated Tables 2 and 3, normalized.

Response IR-9:

(a) Cause Codes 1, 2 and 4 were not applicable from April 26 to August 4, 2025, inclusive.

(b) The ELIADC Tariff performance and benefits are equal to the delta between the levelized CBL Energy Charge and the incremental cost to serve PHP’s load over the entire year. The actual ADC benefit, as defined in the Tariff, can not be confirmed until year-end, as it requires a full year of costs to serve PHP’s load to compare against the CBL Energy Charge. Historically, NS Power would report quarterly estimates that would be indicative of the expected the annualized delta as part of the Quarterly FAM Report. These indicative amounts were never billed to PHP, as it would be the final amount in the ELIADC Tariff Annual Report that would be billed to PHP.

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1 As result of the cyber incident, no indicative amounts were reported in Quarterly FAM
2 Reports. There was no impact on the calculation of the final annual amounts for the cost to
3 serve PHP.

4
5 Cause Code data is not used in the calculation of ELIADC Tariff performance or benefits.
6 Accordingly, the unavailability of some Cause Code data had no impact on the assessment
7 of performance and benefits of the ELIADC Tariff for the reporting period.

8
9 (c) Comparison between the Cause Code data in 2025 and previous years is difficult due to
10 the change in how PHP was dispatched in the aftermath of the cyber incident and the effect
11 on Cause Codes 1, 2, and 4. Comparisons between other years, and Cause Codes 3 and 5
12 in 2025 to other years, are unaffected. Please also refer to BW IR-6.

13
14 (d) Cause Code data cannot be estimated for the period in which it was unavailable, because
15 the mode of dispatch was such that Cause Codes 1,2, and 4 were not applicable. Namely,
16 since there was no real-time PHP dispatch schedule, and since PHP dispatch decisions were
17 made by the NSPSO in collaboration with PHP, there was no schedule against which PHP
18 could deviate with Cause Codes 1, 2, and 4.

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1 **Request IR-10:**

2
3 **Has NSPI omitted any data, analysis or internal assessments from the Annual Report**
4 **regarding ELIADC operations in 2025 that were available to NSPI, on the basis that such**
5 **information will not be required under a successor tariff? If so, please explain.**

6
7 **Response IR-10:**

8
9 **No.**

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Request IR-11:

(a) For each FAM Audit recommendation not yet implemented, please explain why it was not implemented prior to filing the 2025 Annual Report and when NSPI expects implementation to be complete (if at all).

(b) Please provide a copy of any FAM SWG presentation materials and internal analysis done by NSPI regarding any outstanding directives and commitments.

Response IR-11:

(a-b) There are two Audit Action Plan items relevant to the 2025 ELIADC Annual Report, XV-1 and XV-3. The work for both of these was implemented prior to the 2025 ELIADC Tariff Annual Report. Note that data associated with the implementation of XV-3 was temporarily inaccessible due to the cyber incident and so could not be reported on in the ELIADC Annual Report in March 2026, but is expected to be available shortly. The details on both Action Plan items are discussed below.

Recommendation XV-1

As discussed in IG-IR 13, from the outset NS Power indicated that the prescribed action in Recommendation XV-1 to determine hourly benefits and costs associated with Cause Codes 1 through 4, may not be feasible. Nonetheless, NS Power remained willing to pursue what might be feasible both from a modelling perspective and from a Tariff requirements perspective. Specifically, please refer to NS Power's initial response to Recommendation XV-1 in its September 2024 Evidence that followed Bates White's filing of the 2022-2023 FAM Audit Report. There, NS Power states: "NS Power accepts this recommendation and will seek what accurate and feasible approaches exist that are consistent with requirements

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1 set out in the ELIADC Tariff, to account for benefits and costs by cause code, and report
2 its findings to the FAM SWG.” [emphasis added].

3
4 NS Power reported its findings soon after, at the Q1 2025 FAM Small Working Group
5 (SWG) meeting, confirming the action proposed was not feasible and that the
6 recommendation XV-1 would remain open for further review by Bates White. Please refer
7 to IG-IR 13 which provides the update that was provided to the FAM SWG, and page 7 of
8 the 2025 ELIADC Tariff Annual Report.

9
10 Recommendation XV-3

11
12 However, in its efforts to provide useful and meaningful quantifications, NS Power
13 continued to pursue and, in the 2025 ELIADC Tariff Annual Report, has provided more
14 data and metrics and has additionally expanded modelling and calculations of the actual
15 benefits of ADC load shifting which the Tariff methodology cannot provide. This work is
16 captured by FAM Audit Report Recommendation XV-3. The expanded modelling is
17 PortOps-based using a backcast methodology. Although the methodology was already
18 developed and in place well before the 2025 ELIADC Tariff Annual Report, modelling for
19 2025 had to be paused due to the cyber incident. By early 2026, following PortOps
20 restoration, the necessary data required for the 2025 backcast had to be collected and
21 backfilled to enable the models to continue to run, as well as testing of the model to ensure
22 that it ran properly in the new version of PortOps which followed the cyber incident. Please
23 refer to the FAM SWG updates below. NS Power anticipates being able to demonstrate the
24 modelling outputs by the Q2 2025 FAM Small Working Group Meeting.

25
26 NS Power added a table to the ELIADC Tariff Annual Report to show a comparison to
27 prior years’ ELIADC Tariff results. Additional quantification of actual load shifting
28 benefits and deviation analysis is still in progress. NS Power intends to include a more
29 detailed quantification of actual load shifting benefits in the 2025 ELIADC Tariff Annual

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1 Report, pending discussion with Bates White with respect to the appropriate level of detail
2 within the limits of system dispatch model accuracy. The following updates were provided
3 to the FAM SWG:

- 4 • June 2025 update – (from Closing) The 2025 ELIADC Tariff Annual Report is due
5 to be filed on March 26, 2026, and will contain the more detailed quantification of
6 actual load shifting benefit pending discussion with Bates White as referenced
7 above.
8
- 9 • September 2025 update – no new update.
10
- 11 • December 2025 update – no new update.
12
- 13 • March 2026 update – The Company has implemented additional reporting metrics
14 and data, as requested in Recommendation XV-3, consistent with the Board’s
15 direction in the 2023 Report (M12123), and the Board’s M12184 Order, in Table
16 1-3 of this correspondence. With respect to “more detailed quantification of actual
17 load shifting benefits (and costs),” the Company continues to investigate whether
18 and how this analysis may be able to be compiled, particularly in light of the
19 restoration timing for key data and platforms (PI, PortOps). The Company will
20 discuss this further at an upcoming meeting with the FAM Small Working Group.
21

22
23 The required work for the two relevant recommendations outlined above was implemented
24 prior to the 2025 ELIADC Tariff Annual Report.

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Request IR-12:

Reference: 2025 Annual Report, Exhibit N-1, p. 7 and 8/9

Preamble: In response to Recommendation XV-3 in the 2022-2023 FAM Audit Report (M11533), NSPI states that it has updated Tables 1, 2 and 3 comparing 2025 and prior year ELIADC Tariff outcomes. However, with respect to “more detailed quantification of actual load shifting benefits (and costs),” NSPI states that it “continues to investigate whether and how this analysis may be able to be compiled, particularly in light of the restoration timing for key data and platforms (PI, PortOps),” with further discussion deferred to an upcoming meeting with the FAM Small Working Group.

(a) Is NSPI saying that it cannot currently provide more detailed quantifications as a result of the cybersecurity incident and is currently unable to access some of the necessary data on PI and PortOps? If not, explain what NSPI means when it says it “continues to investigate”.

(b) If so, please explain precisely what data is currently unavailable due to the restoration timing of the PI and PortOps platforms, and provide an estimate on when NSPI expects these platforms to be fully restored and operational for this purpose.

(c) Does NSPI agree that the absence of this data affects the ability to properly assess the current ELID Tariff and to quantify the actual load-shifting benefits proposed to be compensated to PHP? If not, please explain the basis for that view.

(d) Please confirm what specific steps NSPI has taken since its acceptance of Recommendation XV-3 in September 2024 to develop a more detailed quantification

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1 **of actual load shifting benefits and costs and provide a timeline for completion of this**
2 **work.**

3
4 Response IR-12:

5
6 (a) NS Power’s response to the “more detailed quantification of actual load shifting benefits
7 (and costs)” portion of Recommendation XV-3 from the 2022-2023 FAM Audit Report
8 has been delayed by the cybersecurity incident. Please refer to SBA IR-4 part (a) for further
9 details.

10
11 (b) No pertinent data is currently unavailable; however, as provided in part (a) and SBA IR-4,
12 the restoration of prioritized systems took precedence over this modeling. The data
13 pertaining to previous years, and required for more detailed quantification of actual load
14 shifting benefits (and costs), as it pertains to comparison of current year outcomes to
15 previous years, is still unavailable.

16
17 (c) No. The ELID Tariff is not yet approved by the NSEB. The data required to assess the
18 benefits of load shifting under the future ELID Tariff will be retained and processed once
19 an ELID Tariff is approved and active. In the ELID Tariff Application (M12661), the
20 Company provided an estimate of the potential forecast savings (\$7 to \$11 million) and the
21 estimated achievable benefits (\$3.5 to \$5.5 million). By comparison to the charges
22 applicable to the PHP baseline ELID Tariff charges, applied on an embedded cost, above-
23 the-line basis, potential variances in the range of outcomes applicable to the load shifting
24 benefit remains a relatively small component.

25
26 (d) Internal modeling of actual load shifting benefits of ADC, which normalizes the results for
27 the impact of commodity price volatility, had begun before the formal acceptance of
28 Recommendation XV-3, and continued up until the cyber incident in April 2025 with the

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1 return of PI and PortOps, as well as the upgrade of PortOps to the most recent software
2 version.

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Request IR-13:

Reference: 2025 Annual Report, Exhibit N-1, p. 7/9

Preamble: Recommendation XV-1 provided that “NSPI should be required to develop a benefits calculation that takes into account the hourly benefits and costs of PHP load deviations based on hourly quantities and prices, by cause code type, to the extent possible.”

NSPI has now confirmed:

After investigation and internal discussions, NS Power has concluded that it is unable to develop an hourly cost and benefit analysis of all individual Cause Codes. Modeling and isolating the costs and benefits of individual Cause Codes would necessitate the creation of several discrete models in the Portfolio Optimization (“PortOps”) software which would result in overlapping, incompatible dispatch results (e.g. unit starts and shutdowns which are in conflicting positions across the models). These conflicting results would collectively show a system that not only did not exist, but one which is not plausible.

Even if the PortOps software had the capability to segregate and execute the simulations required to assess the costs associated with each deviation code, the relatively low load level associated with each individual cause code is too low for the precision tolerance of the PortOps model, relative to the overall system load. The relatively low load increments and decrements associated with individual cause codes can result in unintuitive and contradictory results due to unit commitment variation across scenarios associated with individual cause codes in the model, contributing to unreliability of the analysis.

(a) Given that NSPI previously accepted Recommendation XV-1 in September 2024, please explain:

(i) What assessment, if any, was undertaken prior to that acceptance of this recommendation as to NSPI's ability to implement it; and

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1 (ii) **Why NSPI did not raise these implementation barriers at the time of**
2 **acceptance or in any subsequent proceeding before the Board?**

3
4 (b) **Given NSPI's conclusion that it cannot implement Recommendation XV-1, does NSPI**
5 **propose to seek formal relief from or modification to this obligation? Please explain.**

6
7 (c) **Does NSPI propose any alternative methodology as a substitute to demonstrate the**
8 **hourly costs and benefits of PHP load deviations by cause code? Please explain and**
9 **provide any internal analysis completed.**

10
11 (d) **Please explain why NSPI is unable to calculate hourly benefits or costs under all**
12 **Cause Codes, when it is able to do so in relation to Cause Code 5 (calculated as**
13 **\$706,609 in impact on system costs for off-schedule hours).**

14
15 (e) **In light of this determination, does NSPI plan to modify or enhance any cost or load**
16 **tracking practices under the ELIADC or the proposed ELID to enable accurate**
17 **tracking of hourly load-shifting benefits or costs? Please elaborate.**

18
19 Response IR-13:

20
21 (a)

22 (i) Prior to acceptance of this recommendation, NS Power had internal discussions
23 with subject matter experts regarding Recommendation XV-1. Although subject
24 matter experts raised concerns with the feasibility of this recommendation, NS
25 Power wanted to explore the realm of the possible, and determine the extent to
26 which compliance with this recommendation was possible. Discussions continued
27 regarding Recommendation XV-1 following its acceptance, and attempts to
28 construct software model structures required to comply with this recommendation,
29 which led NS Power to determine that the full implementation of this

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1 recommendation would not be feasible, confirming the original concerns of subject
2 matter experts.

3
4 (ii) NS Power did raise the recommendation implementation barriers. In the FAM
5 Audit (M11355) NS Power Reply Evidence, NS Power stated the following:

6
7 NS Power accepts this recommendation and will seek what accurate and
8 feasible approaches exist that are consistent with requirements set out in the
9 ELIADC Tariff, to account for benefits and costs by cause code, and report
10 its findings to the FAM SWG.

11
12 In the first update to the FAM Small Working Group (SWG) in March 2025,
13 following the acceptance of this recommendation, NS Power stated the following:

14
15 NS Power has developed a benefits calculation which reaches
16 beyond the definition in the ELIADC Tariff, in order to determine
17 the actual benefits of active demand control by the System Operator.
18 As part of this work NS Power has determined that while the overall
19 annual ADC benefit can be assessed using hourly production
20 simulation tools (PortOps), the precision of production simulation
21 tools does not allow for accurate estimate of the effects of each
22 individual cause code due to relatively low load associated with each
23 cause code as compared to the total system load. Analysis of the
24 effects of each cause code outside of the simulation (in Excel)
25 cannot yield accurate results because it is impossible to determine
26 the effect of individual load deviations on subsequent load recovery,
27 outside of the comprehensive production simulation. NS Power will
28 discuss the individual cause code benefits/cost analysis with Bates
29 White to determine the best path forward within the realm of
30 possible.

31
32 (b) NS Power intends to discuss the technical challenges with the implementation of this
33 recommendation with Bates White during the course of the 2024-2025 FAM Audit and
34 propose an alternative approach to assessing the benefit of load shifting and the effect of

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1 cause code deviations. This is consistent with the Board's direction in M11533, the 2022-
2 2023 FAM Audit Decision, where at paragraph 240, the Board indicated:

3
4 In the event NS Power considers that a different implementation strategy
5 should be adopted from that suggested by Bates White, it is to explain the
6 new approach and the reasons for the change of course, along with an
7 anticipated timeline for completion.
8

9 NS Power provided the following in its most recent FAM Audit Action Plan update to the
10 FAM SWG on March 27, 2026:

11
12 After investigation and internal discussions, NS Power has concluded that
13 it is unable to develop an hourly cost and benefit analysis of all individual
14 Cause Codes. Modeling and isolating the costs and benefits of individual
15 Cause Codes would necessitate the creation of several discrete models in
16 the Portfolio Optimization ("PortOps") software which would result in
17 overlapping, incompatible dispatch results (e.g. unit starts and shut downs
18 which are in conflicting positions across the models). These conflicting
19 results would collectively show a system that not only did not exist, but one
20 which is not plausible.

21
22 Even if the PortOps software had the capability to segregate and execute the
23 simulations required to assess the costs associated with each deviation code,
24 the relatively low load level associated with each individual cause code is
25 too low for the precision tolerance of the PortOps model, relative to the
26 overall system load. The relatively low load increments and decrements
27 associated with individual cause codes can result in unintuitive and
28 contradictory results due to unit commitment variation across scenarios
29 associated with individual cause codes in the model, contributing to
30 unreliability of the analysis.

31
32 Furthermore, PortOps uses daily and hourly forward replacement costs,
33 while PHP is billed on its actual accounting costs. It is impossible to obtain
34 daily and hourly granularity of average accounting costs. Therefore, even if
35 the cost and benefits of individual cause codes could be calculated, they
36 would be expressed in forward replacement costs, which are not directly
37 comparable to average accounting costs.

38
39 Accurately calculating all of the Cause Codes' costs and benefits on an
40 hourly basis outside of PortOps using Microsoft Excel is not possible

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1 because of the lack of complex mixed integer optimization algorithms
2 required for unit commitment optimization. The Company will discuss this
3 finding further at an upcoming quarterly meeting with the FAM Small
4 Working Group.
5

6 (c) Yes. A comprehensive monthly calculation of hourly load shifting benefit looking at all
7 hours of the month is possible. This calculation is presently done annually for internal
8 analysis. NS Power will explore the possibilities with Bates White with respect to
9 enhancing this calculation to reflect the requirements of the recommendation, to the extent
10 possible.
11

12 (d) The calculation of Cause Code 5 costs is a prescribed part of the ELIADC Tariff and is
13 formulaic. The nature of load deviations associated with other Cause Codes, is such that
14 the benefit/cost cannot be assessed in a formulaic way similar to the Cause Code 5
15 assessment.
16

17 (e) NS Power intends to implement a comprehensive calculation of load shifting benefit, based
18 largely on the existing and tested internal load shifting benefit analysis process. This
19 commodity-price neutral calculation of the DR Credit is a comprehensive calculation of
20 total DR benefits which is intended to be a part of the ELID Tariff process.

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1 **Request IR-14:**

2
3 **Does NSPI consider the 2025 ELIADC Annual Report to be a complete and accurate**
4 **representation of ELIADC performance for purposes of informing the Board's**
5 **consideration of a successor tariff? Please explain.**

6
7 **Response IR-14:**

8
9 The 2025 ELIADC Annual Report accurately represents the ELIADC Tariff performance and
10 outcomes and provides the information necessary to inform the Board's review of ELIADC Tariff
11 performance in 2025. While historical ELIADC Tariff operational experience informed the ELID
12 Tariff design, the Board's consideration of the proposed ELID Tariff is supported by the
13 comprehensive evidence filed in that proceeding (M12661).

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Request IR-15:

(a) Please file NSPI's response to NSEB IR-3 in M12227 (2024 Annual and Regulated Financial Statements) for the purposes of this proceeding.

(b) Please produce a table for each year, 2020-2025, comparing ELIADC and Large Industrial Revenues in \$, energy sales in GWh and revenue in ¢/kWh.

Response IR-15:

(a) Please refer to Attachments 1 and 2.

(b) Please refer to the table below.

Year	2020	2021	2022	2023	2024	2025
ELIADC Tariff						
Energy Sales (GWh)	875	966	957	670	766	691
Revenue (\$M)	55.5	60.3	170.1	28.3 ¹	77.7	70.9
Revenue (¢ per kWh)	6.3	6.2	17.8	4.2	10.1	10.3
Large Industrial Tariff						
Energy Sales (GWh)	726	759	753	730	675	637
Revenue (\$M)	76.4	80.4	82.9	84.6	82.9	81.9
Revenue (¢ per kWh)	10.5	10.6	11.0	11.6	12.3	12.8

¹ The 2022 ELIADC Tariff Annual Report and change in methodology for calculating the cost to serve PHP load was approved by the Board on July 5, 2023 (M11021), which resulted in a \$50.9 million adjustment to 2022 fuel recovery for the ELIADC Tariff as compared to the preliminary indicative calculation using forward replacement pricing.

**2024 Annual and Regulated Financial Statements (NSEB M12227)
NSPI Responses to NSEB Information Requests**

NON-CONFIDENTIAL

Request IR-3:

With regards to Attachment 1, Regulated Operating Revenues, page 3 of 6:

Please provide a detailed breakdown of actual and forecasted revenues and corresponding energy sales (in GWh) by customer class for each year from 2020 through 2024. For each class and year, please include total revenue in dollars, total energy sales in GWh, and, if available, average revenue per kWh (¢/kWh). Additionally, please identify any major factors contributing to changes in revenue or sales volumes over the period.

Response IR-3:

Please refer to Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2025 ELIADC IG IR-15 Attachment 2 has been filed electronically.