Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to CA Information Requests

NON-CONFIDENTIAL

Request IR-1:

In Appendix J (p. 2), is the paragraph beginning with the words "As a result" a quotation, as suggested by the formatting? If so, please provide the source.

Response IR-1:

No, the indented paragraph that begins with "As a result" is not a quotation. This is a formatting error.

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Request IR-2:

Please explain whether the energy served for the GRLF, Shore Power, BUTU, Spill, and Energy Balancing Service rates is included in the load forecast used for system planning purposes and, if so, on what basis the peak demand for each rate is also included in the load forecast.

Response IR-2:

GRLF and Shore Power are included in the interruptible load and are not used for system planning. The full peak related to the Muni customers served by BUTU is included in the firm load as described in Section 7.4 of the 2025 Load Forecast Report. Spill energy is not included in peak calculation. Energy Balancing Service is a tariff provided through Renewable to Retail (RTR), and the full peak load of RTR customers is included in the firm load as described in Section 4.6 of the 2025 Load Forecast Report.

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Request IR-3:

In its letter of January 31, 2025, NS Power stated that it would "prepare a proposal outlining the change in methodology for the calculation of the FCA component of 1P-RTP Tariffs for distribution to stakeholders in Q2 2025, for review at the first stakeholder session."[1] Please explain whether this occurred and, if not, why not.

Response IR-3:

No. NS Power did not schedule the Q2 2025 stakeholder session to discuss the topics outlined in the Company's January 31, 2025 letter, for a number of reasons, including:

- On March 25, 2025, the Board issued its 2025 AAR Decision (M11989) directing NS Power "review the issue no later than in the 2026 AAR application."[2] In relation to TVP structure for AARs, the Board also directed NS Power "engage with stakeholders on developing on-peak and off-peak AARs following the completion of the TVP pilot evaluation."

- In April 2025, the reallocation of NS Power resources was required to support cybersecurity incident response efforts. This led the Company to postpone other scheduled stakeholder sessions, and NS Power was not in a position to initiate new stakeholder sessions in Q2 2025.[3]

- Finally, as noted in this Application, "no comments were provided on the proposed 1P-RTP methodology change" [4] outlined in NS Power's January 31, 2025 letter.

[1] NS Power, Letter re: Update on Items Arising from 2024 and 2025 Annually Adjusted Rates Proceedings (January 31, 2025), Matter No. M11989.
[2] M11989 – Board Decision, 319292, page 6. March 25, 2025.
[3] The third Time-Varying Pricing (TVP) Technical Session was postponed in May 2025.
[4] At page 19, lines 23-26 provided "NS Power sought feedback on its plan to propose an alternate methodology based on marginal system fuel costs in the 2026 AAR application. While feedback was received on the time-variable

In light of the factors above, the Company assessed the options to engage stakeholders on the review of the issue in accordance with the Board's direction. NS Power issued a second memorandum on October 15, 2025 to request stakeholder feedback on the Company's plan to eliminate the avoided fuel cost adjustment, apply hourly marginal energy costs for energy charges, and include only non-fuel costs in the fixed cost adders, and proposed future 1P-RTP adjustments be reviewed as part of GRAs.

No stakeholder comments on this second memorandum were received.

AAR aspect of the memorandum (as described in Section 1.2), no comments were provided on the proposed 1P-RTP methodology change."

Request IR-4:

In the 2025 AAR proceeding, NS Power stated that the impact of recent emissions standards on the 1P-RTP tariff "will continue to adversely affect the methodology until system dispatch is no longer tightly constrained by the SO2 emissions limit" and when "renewable energy sources are added to the system it is expected that this … issue will subside."[1] In its letter to intervenors, NS Power wrote, "The growing complexity of the air emission market makes the continued application of the current avoided fuel cost methodology increasingly difficult, it leads to volatile results, and therefore is unreliable."[2]

(a) Please explain whether it is still NS Power's position that the SO2 emissions limit will not be an issue for the design of the 1P-RTP Tariff after renewable energy sources are added to the system. Please address this question specifically without relation to the second reason for NS Power's proposed departure from the use of avoided fuel costs under the 1P-RTP Tariff.

(b) NS Power further stated,

> **"An argument can be made that the system composition would look different if the system resources mix was developed for the lower load case resulting from the load decrement analysis. Therefore, the present system configuration may not realistically simulate the load decrement case."[3]**

Considering the <u>circumstances anticipated for 2026</u>, please identify how the system composition might differ if the load served under the 1P-RTP Tariff was not present on NS Power's system.

[1] Exhibit N-2, Matter No. M11989, CA RIR-5(b).
[2] Exhibit N-1, Appendix J, p. 2.
[3] Exhibit N-1, Matter No. M11989, p. 17.

(i) In your response, please specifically address the hypothesis that the marginal system capacity for 2026 would be shifting Lingan 2 from cold reserve to full retirement status.

(ii) If your response to subpart (i) is that Lingan 2 represents the marginal system capacity, please state whether removing the load served under the 1P-RTP Tariff would be sufficient for NS Power to shift Lingan 2 from cold reserve to full retirement status and, if so, provide the associated avoided costs.[4]

(iii) If your response to subpart (i) is that some other unit capacity represents the marginal system capacity for 2026, please identify that capacity and provide the associated avoided costs.

(iv) Please explain how the avoided costs referenced in your response are included in the proposed 1P-RTP Tariff design. If no such avoided costs are included, please confirm that your proposal assumes that the system resources mix that would be developed for a lower load case resulting from the load decrement analysis would not differ from the present system configuration. If not confirmed, please explain.

(c) Please provide an alternate version of Appendix B2 using the SO2 adjustment method approved for 2025 but otherwise retaining the same structure (removing the HV rate).

(d) Please summarize the total costs forecast to be recovered under the proposed 1P-RTP and the alternate 1P-RTP (as provided in response to part (c) above) rates, and explain any material differences in the total cost recovery.

(e) NS Power further states,

[4] See Exhibit N-1, 2025 10-Year System Outlook, Matter No. M12386, p. 18.

> **In view of the foregoing [referencing the SO2 emissions limit], NS Power has, in this Application, eliminated the adjustment for the projected imbalance in the recovery of the avoided fuel. Energy charges under these tariffs are proposed to be based on hourly marginal costs, and the fixed cost adders are proposed to include only non-fuel costs.[5]**

And:

> **The fuel cost imbalance arises from employing hourly marginal costs, as opposed to hourly average avoided fuel costs, in energy charges on customer bills. Since the differential between hourly marginal and hourly avoided fuel costs can be volatile, the projected annual fuel cost imbalance can vary and cause fluctuations in the adders from one year to the next. As designed, the combined tariff components collect the overall intended costs.[6]**

(i) Please confirm that the only justification specifically cited in the Application for eliminating the "adjustment for the projected imbalance" is the SO2 emissions limit issue.

(ii) Please explain any other reasons that NS Power has for eliminating the "adjustment for the projected imbalance."

Response IR-4:

(a) With the recent change in air emission regulations, SO_2 limits are better aligned with the expected development of renewable resources and the cost of carbon. This alignment allows NS Power to dispatch lower-cost coal generation while these renewable assets are being built and coming online, while maintaining the ability to comply with total SO_2 emissions by the end of the decade. However, as indicated in Section 5.1 of the 2025 AAR Application (M11989), modeling of the SO_2 limit was not the only challenge faced by the Company. NS Power is subject to not only SO_2, but also Mercury, Nitrous Oxides, and

[5] Exhibit N-1, p. 20.
[6] Exhibit N-1, Appendix J, p. 3.

GHG emissions regulations. When one of the annual air emissions limits is relaxed, one of the remaining limits becomes a binding constraint. Another challenge is posed by the growing share of the non-dispatchable must run renewables in compliance with the Renewable Electricity Standard (RES), and RES' interaction with Output Based Pricing System (OBPS) compliance costs. As more renewables are integrated on the system, more expensive carbon-emitting generation will go to smaller loads when avoided cost methodology is used. This would imply that compliance costs would be unfairly proportioned to those loads which are avoided. Please also refer to part (b) and IG IR-3.

(b) The planning process for generation resources considers total system requirements, including eligible 1P-RTP load (approximately 10 percent of total system load). This planning process includes the available generation resources and the timing and size of new renewable generation, which has been added in recent years and is forecast to continue. If this load were removed, fewer renewable resources may have been selected during planning coincident with the approximately 10 percent lower overall capacity requirement. The specific hypothetical resource mix selected in a 'no 1P-RTP' scenario would need to be modeled in order to accurately be determined. Further, these renewable units are non-dispatchable and therefore do not change under a decremental analysis. Their output remains constant regardless of load changes, meaning the decrement methodology primarily affects thermal generation and compliance costs rather than renewable capacity decisions.

(i) The system capacity requirement to keep Lingan 2 in cold reserve is not a significant factor in determining the cost of serving the 1P-RTP load as the unit is not generally required to serve load in PLEXOS. The actual sales to this customer class are not expected to be sufficient to change the status of Lingan 2.

(ii) Please see the response above.

(iii) The assertion is that fewer new renewable resources may have been selected in the hypothetical load case; however, these are not dispatchable units, with their energy being integrated on the system when available, and therefore are not marginal units. Their output does not change using the load decrement methodology. This means that decrementing a significant portion of load will reduce generation from only the most expensive forms of generation, which also incur high GHG OBPS costs, thereby distorting costs allocated to those customers and not accurately reflecting the significance of assumed load on resource planning.

(iv) The statement is not about system capacity costs; it is about the distribution of generation costs. The methodology based on marginal pricing is based on the cost of an additional MW of generation which is better aligned with the reality of serving this relatively small load. The load being served is much lower than that modeled under the previous methodology.

(c) This analysis was not performed for 2026 AARs and would require significant additional modeling and calculation.

(d) Please see the response above.

(e)

(i) Not confirmed. Aside from the SO_2 emission limit issue, there is a challenge in how to reconfigure the system generation mix, inclusive of RES-based non-dispatchable renewable generation, in the lower load decrement system case. Also, the apportionment of GHG OBPS Fund and Performance credits would be complex and speculative. Please also refer to part (b) and IG IR-3.

(ii) Additional reasons include the growing complexity of modeling decremental costs, particularly with increasing renewable penetration and associated compliance costs. The proposed change to the 1P-RTP methodology also aligns the fuel cost

recovery under these Tariffs with the marginal cost-based methodology applied to several other AARs since 2017. In accordance with the 2017 Board Decision M08114,[7] the energy charges of the Generation Replacement and Load Following, Shore Power, Back-up/Top-up, Wholesale Market Spill, and Energy Balancing Service Tariffs had the fuel cost rate components, made up of avoided costs of a 25 MW decrement, replaced with the marginal fuel cost methodology of applicable to the next MWh. The marginal cost approach better reflects the cost of serving incremental load and avoids volatility associated with avoided fuel cost calculations. Please refer to page 2 of Appendix J.

[7] M08114 – Board Decision, 258834. October 24, 2017.

Request IR-5:

In its 2018 AAR application, NS Power stated that the "the marginal hourly costs of the next MWh are determined by the incremental costs of the source of generation on the margin in each hour."[1] In that same application, NS Power explained that changes in system demand can "cause a coal unit to be shut off because it cannot run below its minimum stable level;"[2] this raises the topic of unit commitment costs.

Please explain how each of the following 1P-RTP Tariff designs collects unit commitment costs that result from the additional demand:

(a) as approved in the 2024 AAR decision;

(b) as approved in the 2025 AAR decision, and

(c) as proposed in the 2026 AAR application.

Response IR-5:

(a) The cost of unit commitment is directly included in the decremental load or avoided cost methodology because the costs compared include all committed units over the year in both cases. This includes unit start and stop costs, and the cost of operating units at minimum load if that is the most economic dispatch calculated in the model. These costs are again based on the load eligible for the rate class which is significantly higher than actual sales.

(b) The same methodology was used in 2025 AAR calculation in terms of costs included, only the SO_2 limit was pro-rated proportional to the load being decremented.

[1] Exhibit N-1, Matter No. M08383, p. 8.
[2] Exhibit N-1, Matter No. M08383, p. 8.

(c) Marginal rates do not include unit start and stop costs which is more appropriate for the relatively small proportion of load actually attributable to 1P-RTP customers.

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REDACTED

Request IR-6:

In its decision on the 2025 AARs, the Board stated:

> **The Board agrees with Mr. Wilson that it is prudent to have a sensitivity analysis for potential delayed wind resources in the 2026 AARs. In the 2025 ACE Plan M12012, Appendix H lists several wind projects that are expected to go into service in 2025 and 2026. Given the circumstances, it is important to ensure that rates are set on reasonable assumptions and are accurate. The Board seeks to understand how the AARs will be affected if some, or all, of these resources miss their target in-service dates. The Board considers that NS Power is in the best position to identify realistic scenarios for sensitivity analyses. NS Power is directed, in the 2026 AAR application, to provide scenarios of delays to wind resources scheduled to go into service in 2025 and 2026 and explain the assumptions it applies in the sensitivity analyses.**[1]

In its application, NS Power states that it "does not believe the 'no new wind' scenario to be indicative of a plausible outcome for 2026."[2]

(a) Please explain why NS Power submitted a sensitivity analysis that it believes is not "plausible" in response to a board directive to identify a "realistic" scenario.

(b) NS Power further states, "In addition, the forecast, as developed in Q3 2025, reflects the latest available information reducing the likelihood of an alternate scenario from the anticipated full operation planned 2026 wind sites."

(i) Please provide the Q3 2025 forecast for wind site operation.

(ii) Please explain the difference between the forecast and the "anticipated full operation" as suggested by the use of the phrase "alternate scenario." If there

[1] NSUARB Decision, Matter No. M08383, p. 5-6.
[2] Exhibit N-1, Matter No. M08383, p. 13.

is no difference between these two points, please explain what is meant by "an alternate scenario."

(c) Please provide an alternate scenario that reflects a delay in some, but not all, wind projects to 2027.

(d) Please explain whether NS Power views the Sensitivity 4 results as indicating a material difference if it were used as the basis for rates. If the answer differs by rate, please state your opinion by rate.

Response IR-6:

Please see NSEB IR-4 regarding the error in Appendix A6.

(a) The result of the wind sensitivity demonstrates that the impact on annual average marginal costs is approximately five percent despite the scenario being very conservative in terms of potential wind resource delays in 2026. Given the progress reports available to NS Power at the time of filing, the timing risk and associated potential impact on Marginal Rates in 2026 is low, the sensitivity performed reinforces this conclusion.

(b) (i) Please refer to the figure below.

Site Name	Nameplate Capacity (MW)	Forecast in-Service Date
[redacted]		

(ii) There is no difference between the Q3 2025 forecast for wind site operation and the anticipated full operation. The phase "alternate scenario" is meant in the generic

sense of any timeline that deviates significantly from what is currently forecast such as the sensitivity scenario that was provided in the filing.

(c) As the provided sensitivity which is considered a "worst case scenario" in terms of new wind resource timing for 2026 had only a five percent impact on annual marginal costs, NS Power does not believe there would be value in modeling a less severe scenario at this time.

(d) The sensitivity only considers the impact on average annual marginal rate and the impact is an approximately five percent increase. The scenario is intended to assess the sensitivity of the rate to a change in timing of new wind resources not as the basis for the rate. The Application represents the Company's best information on timing of these resources and is what is being proposed for setting the AARs.

REDACTED

Request IR-7:

Re: Application, p.14 and Confidential Appendix A7, identifying factors that cause actual import volumes to vary from forecast.

(a) Please provide a list of the factors, including but not limited to those identified in Confidential Appendix A7, that NS Power believes may have caused actual import volumes to materially vary from forecast during the years identified in the Board Decision (2021-2025).

(b) Please explain whether NS Power expects any of the factors listed in its response to part (a) to drive variation in imports from the NB/ISONE market during 2026.

(c) Please state when the forecasts for the following factors that could affect import volumes were developed, how the following factors were considered in those forecasts, and note any material changes in NS Power's understanding of those factors that have occurred since the forecasts were developed.

(i) Availability of each energy product (e.g., NS Block, surplus) forecast for delivery via the Maritime Link.

(ii) Outages of any major generation units (e.g., NB or NLH units).

(iii) Environmental regulations.

(d) Does the use of a historical average adequately account for material changes in the factors discussed in parts (b) and (c)? If NS Power does not believe so, please provide a sensitivity analysis that adequately accounts for such changes.

(e) Please provide a comparison of monthly forecast import volumes and monthly model import limits for 2026.

Response IR-7:

(a) As stated in the application, due to the cyber event and ongoing recovery, a comparison between forecast and actual imports are only available between January and September 2025. No additional factors beyond those listed in Appendix A7 have been identified.

(b) Factors such as variability of import volume availability due to generating unit or transmission availability, or a change in market conditions relative to NS Power's current assumptions might occur in 2026, those changes could drive variances in the forecasted imports from the NB/ISONE market as has been seen in previous years. NS Power strives to use the most current information available to it in developing the forecast.

(c) NS Power evaluates its import assumptions for both the NB and Maritime Link ties every time it does a forecast. This evaluation includes those stated below.

(i) Base Block and Supplemental energy deliveries are modeled according to the agreed upon schedule adjusted only for posted transmission outages on the public Newfound and Labrador System Operator OASIS site. Surplus Energy deliveries are based on the 24-month on- and off-peak schedule provided monthly by NLH with adjustments made to the monthly and annual totals based on historic deliveries and market expectations.

(ii) If NS Power is aware of major unit outages in NB and at NLH import volume assumptions are reviewed and revised as necessary to align with the anticipated impact on import availability.

(iii) Any known annual change in existing environmental regulation such as emission limits are incorporated into the PLEXOS model as they may impact the volume of imports selected by the model. Any new environmental regulations are generally incorporated into the model once they have been passed into law.

(d) The historical average deliveries are adequate to serve as the basis for available import volumes in the model. These are then adjusted as discussed in part c based on known factors such as unit availability or posted transmission outages. The PLEXOS model then selects the volume and timing of imports which are expected to be economic based on the pricing data used, and all other relevant assumptions in the model (environmental constraints, etc.). The factors discussed in parts (b) and (c) are considered in addition to historical averages.

(e) Please see the table below.

	NB On-Peak		NB Off-Peak		ML Surplus On-Peak		ML Surplus Off-Peak	
	Limit (GWh)	Volume (GWh)	Limit (GWh)	Volume (GWh)	Limit (GWh)	Volume (GWh)	Limit (GWh)	Volume (GWh)
Jan-26	[redacted]							
Feb-26								
Mar-26								
Apr-26								
May-26								
Jun-26								
Jul-26								
Aug-26								
Sep-26								
Oct-26								
Nov-26								
Dec-26								