Request IR-1:

Appendix A2 presents the annual marginal generation costs by month.

(a) Please explain why [redacted] for February and March.

(b) Please provide the values for Marginal Costs excluding the Output Based Pricing System costs.

(c) Please explain why marginal cost for Peak is forecast [redacted] in June and July.

Response IR-1:

(a) In February and March, the off-peak marginal price is [redacted] than on-peak by [redacted] respectively. This is driven by an hourly dispatch from the system dispatch optimization model which is balancing annual air emissions and renewable energy targets with hourly dispatch by integrating available renewable energy during the off-peak hours by using the more flexible natural gas generation, with a higher proportion of coal generation and lower generation from natural gas in the [redacted] hours for this period. The more flexible natural gas generation is still relatively expensive in this period, while renewable energy must be integrated on the system when available, to satisfy annual targets.

(b) Please refer to the table below. Please note that there is not a "without Output Based Pricing System (OBPS)" scenario as these are actual costs associated with NS Power complying with GHG emission regulations.

Marginal Cost excluding OBPS ($/MWh)			
2026	**Peak**	**Off-peak**	**All**
Jan	[redacted]		

Marginal Cost excluding OBPS ($/MWh)			
2026	**Peak**	**Off-peak**	**All**
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	60.18

(c) June and July are summer months which correspond to a seasonal low in wind generation and fall within the thermal fleet maintenance window which reduces system dispatch flexibility. These situations may result in [redacted] marginal costs despite a generally lower summer load.

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Request IR-2:

In reference to Appendix A4, Update 2:

(a) Please discuss the factors increasing the forecast price for [redacted] relative to 2025.

(i) Is [redacted] sourced exclusively from the Nova Scotia market?

(b) Please explain the difference between the following sources:

(i) [redacted] and [redacted]

(ii) [redacted] and [redacted]

(iii) [redacted] and [redacted]

Response IR-2:

(a) The factors increasing the forecast price for Biomass relative to 2025 are biomass fuel cost and biomass fuel transportation cost.

(i) Biomass is not sourced exclusively from the Nova Scotia market.

(b) These are duplications in the pricing file used by PLEXOS that were provided unnecessarily, the price values used are identical for each pair of fuels.

Request IR-3:

In reference to Appendix A4, Update 9:

(a) [redacted]**?**

(b) **Why have Updates 11 and 12 been omitted from the 2026 Annually Adjusted Rates (AARs)?**

Response IR-3:

(a) The property for these values is "Rating" therefore a value of zero indicates this source of energy was not available during the forecast period. In this case, the object refers [redacted] which is unavailable in the model due to there being no transaction in place with [redacted] during the forecast period.

(b) Updates 11 and 12 were added for the 2025 filing to provide assumptions for the timing of new battery energy storage systems (BESS) and the relevant price of carbon under the OBPS Regulations for the forecast year. The timing of the BESS projects is unchanged from the previous filing. The price of fund credits in 2026 increased to \$110/tCO_2e and the assumed Biomass Performance Standard is also unchanged from the previous forecast.

Request IR-4:

In reference to Appendix A6:

(a) Please explain why the [redacted].

(b) Please discuss the changes to [redacted].

(c) Please explain why [redacted].

(d) Please explain why the average [redacted].

(e) Please elaborate on the increase in [redacted].

Response IR-4:

(a) Please note the reference in the question notes Appendix A6 but the proper reference is Appendix A5. In the previous filing peak load was subtracted from the installed capacity to represent "Total Reserve Margin." The 2026 filing was updated to report the firm capacity which is significantly lower than installed capacity for resources such as wind, solar and BESS but provides for a more relevant comparison to peak capacity and the associated margin. This calculation should not be compared to the 2025 filing.

(b) As discussed in (a), the [redacted] reported has been adjusted to reflect the [redacted] which represents the available resources to serve customer peak demand and therefore allows for a relevant comparison against [redacted] and provides an accurate sense of [redacted]. The [redacted] values used are based on the most recent 10-Year System Outlook report (M12386) adjusted for the timing of the Wreck Cove LEM project, BESS sites, and new wind (two Rate Based Procurement sites and the PHP Wind farm). As shown in the table below, this assumes Wreck Cove Unit #2 is unavailable at the beginning of 2026 but is in service at the end of the year, and that the third BESS facility has been commissioned by the end of 2026.

	Installed Capacity (MW)	**Firm Capacity Added (MW)**
INSTALLED CAPACITY (START OF YEAR)	2,601.8	
WRC#2 Return from LEM		102
White Rock BESS Completion		24
New Wind IPPs		33
INSTALLED CAPACITY (END OF YEAR)	2,760.8	

(c) [redacted] are correlated to coal generation which has [redacted] in the 2026 AAR forecast relative to the 2025 AAR Application. Coal generation is [redacted] due to the increased emissions limit for SO_2.

(d) The category "[redacted]" includes new wind developments. Three [redacted] facilities are forecast to be online in 2026, output from these facilities is the primary driver for an increased generation from this category. The forecasts for all [redacted] facilities are also updated between forecasts to account for recent performance and new information and will therefore vary from year to year. The main driver of increased cost in this category is the change to the Renewable Electricity Regulations requiring IPP biomass generation to be paid the Feed-in Tariff Program rate for biomass.

(e) [redacted] The volume of [redacted] forecast for 2026 has increased relative to 2025 as the PLEXOS model assumption which allowed an annual limit of [redacted] GWh of

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[redacted] in 2025 has been removed for 2026. This is based on improved reliability of the [redacted] which will allow for increased energy flow.

Request IR-5:

Page 11 cites forecasted solid fuel prices decreasing for 2026. Please discuss the factors leading to this decrease, including those associated with output prices for SO2.

Response IR-5:

The forecast decrease in solid fuel prices for 2026 are a result of two main factors. The first reason is related to the annual emission limits of SO_2. This allows NS Power to consume more Mid sulphur and Petcoke fuels in its coal generation. These fuels are generally lower in cost than low sulphur fuels. The second factor is low sulphur coal forward prices are trading at lower prices compared to last year. These factors combine to make blended solid fuel prices lower for the 2026 forecast compared to the 2025 forecast.

Request IR-6:

On page 13 of the application, Nova Scotia Power (NS Power) states that since Q4 2024, the reliability of energy flowing through the Labrador Island Link (LIL) and Maritime Link (ML) has improved with only minor outages. Please provide a table similar to the table found in Appendix A7 with the monthly ML energy from Q4 2024 to the end of October 2025.

Response IR-6:

Please refer to Confidential Attachment 1 for the comparison to the contracted volumes for Maritime Link energy.

NSEB IR-6 Confidential Attachment 1 has been removed due to confidentiality.

Request IR-7:

NS Power did not provide scenarios of delays to wind resources scheduled to go into service in 2025 and 2026.

(a) Please provide a table identifying each wind asset that was scheduled to go into service in 2025 and 2026, the number of MW of each asset and both the planned in-service date and actual in-service date.

(b) Where there were/are delays beyond six months of going into service, please provide explanatory notes.

Response IR-7:

An error was identified on Page 4 of Appendix A6 in the original filing, the corrected results of the sensitivity analysis is shown below:

Sensitivity 4: No New Wind

System Marginal Cost ($/MWh)			
2026	**Peak**	**Off-peak**	**All periods**
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	70.77

(a) The sensitivity analysis for a delay in arrival of new wind resources is discussed in Section 2.2 (4) of the Application, and the result is presented on page 4 of Appendix A6. See the table below for details of new wind resources forecast to be online in 2025 or 2026. Note, the forecast in service dates for new wind resources are in the future and none of the facilities have reached commercial operation at this time therefore the actual in-service dates are to be determined. At the time of writing this IR, it is expected that [redacted] will be testing at some point during the month of December.

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

(b) Not applicable.

Request IR-8:

Appendix E5 provides the calculation for the [redacted]. Please explain how the [redacted].

Response IR-8:

Appendix E5 provides the calculation of the marginal cost-based Demand Charge of $13.430 per kW. This calculation has been provided in support of a four-year phase-in of the embedded cost-based charges under the BUTU Tariff.

By design this calculation uses as an input the annual levelized capacity cost, on the basis of which the interruptible credit is calculated under the Large Industrial Rate. The levelized annual capacity cost of [redacted]/kW-Yr was used for the purposes of calculating the interruptible credit of $7.638/kVA submitted in SR-01 Attachment 8 in the 2026-2027 GRA (M12451). For the derivation of this cost please refer to tab "IOU pro forma" of Attachment 4 Interruptible Rider Calculations[1] filed in the 2026-2027 GRA. The methodology used by the Company to calculate this cost is referred to as Peaker Deferral Method.

[1] M12451 – 2026-2027 GRA SR-01 Attachment 4.

Request IR-9:

In Appendix F3, why is the Interruptible Credit Cost now included in the monthly rate for the Standby Demand Charge Calculation?

Response IR-9:

The monthly standby rate applied for in this Application is a firm service rate of $5.452 per kW of monthly standby contract demand. This rate does not include the interruptible credit. The interruptible service credit of $14.053 per kW of monthly standby contract demand is designed for use by interruptible customers of Licensed Retail Suppliers. This is provided for information purposes to inform pricing in the event of interruptible service in the RtR market.

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Request IR-10:

In Appendix F4, please explain the increase in Average Unit Cost at the Transmission Level from 7.688 to 7.835. How does it align with Appendix D in the Costs by Functional Area tab for the unit costs for Total Transmission in row (13).

Response IR-10:

Please refer to the table below.

	2025	**2026**	**Variance**	**Var (%)**
MWh Energy Requirement at Generator	10,100,338	11,303,785	1,203,448	11.9
Transmission Line Losses (%)	3.0	2.4	-6.0	-20.0
MWh Load at Transmission Level	9,806,153	11,038,853	1,232,700	12.6
Total Fuel Cost of FAM Rate Classes (before Fixed Cost Credits)	$753,854,785	$864,917,556	$111,062,772	14.7
Average Unit Fuel Cost at Transmission Level (cents/kWh)	7.688	7.835	0.148	1.9

The 1.9 percent increase in the Average Unit Fuel cost at transmission level is due to an uneven increase of 12.6 percent in the MWh energy requirement at the low side of the bulk power transformer of the above-the-line (ATL) rate classes and 14.7 percent increase in the fuel costs forecasted to be recovered from the ATL rate classes. For the reasons behind the 12.6 percent increase in the MWh Load, please refer to part (c) of REI IR-13.

There is no alignment between the transmission costs of $139.2 million in row (13) of the Costs by Functional Area tab in Appendix D and the Total Fuel Cost of FAM Rate Classes (before Fixed Cost Credits) of $864.9 million in Appendix F2. The costs in row (13) are the test year costs of the transmission service area, which are non-fuel related, and the costs in Appendix F2 are the test year fuel cost recoveries through the approved base cost of fuel (BCF) rates.

Request IR-11:

Appendix J refers to the 1P-RTP moving from an annually adjusted rate to one set through a General Rate Application. However, toward the bottom of page 2 of 3 in the appendix NS Power states that these "methodological adjustment will align the 1P-RTP tariffs with the costing approach used for other AARs."

(a) Will the High Voltage 1P-RTP customer have the choice to move to the Transmission or an alternate AAR or above the line tariff?

(b) What is purpose of aligning this tariff with the other AARs if it won't be reviewed annually?

(c) What is the benefit to NS Power of adjusting this tariff through a General Rate Application (GRA) instead of the AARs?

(i) What is the benefit to a customer of waiting from this tariff to be adjusted through a GRA?

(1) If NS Power decides to delay making a GRA for several years, what at the risks to both parties?

(d) How many customers took service under the EHV 1P-RTP tariff in 2025?

(i) Did these customers receive the letter from Appendix J?

Response IR-11:

(a) The Company intends to place the High Voltage (HV) 1P-RTP customer, which is the only customer taking currently service under any of the three 1P-RTP tariffs, under the 1P-RTP Transmission rate. The fixed cost adder (FCA) under the proposed Transmission Tariff will reflect the weighted average cost of the less expensive to serve Extra High Voltage (EHV)-connected and more expensive to serve HV-connected loads, eligible for service under the 1P-RTP tariffs. As a result, the proposed FCA applicable to the current HV-connected customer, will be lower than its HV-differentiated alternative.

The 1P-RTP Tariffs are optional. Consistent with Special Condition (5) under the 1P-RTP Tariff, customers, who took service under the 1P-RTP for a minimum of 12 months, can terminate it by giving a 30-day notice before the end of the contract term.

To qualify for service under other AAR or an above-the-line (ATL) tariffs, the 1P-RTP customer would have to meet the eligibility criteria of the tariff, the customer would like to transition its load to. In case of the current 1P-RTP customer, whose partial load is currently served under the Large Industrial Interruptible Rider (LIIR) and whose current 1P-RTP load had also been previously served under the LIIR, the customer may transition its 1P-RTP load to the LIIR subject to meeting Special Condition (5) under the LIIR Tariff.

(b) NS Power's purpose in making the aforementioned statement was to make a reference to the costing methodology used in determination of the fuel cost component of other AARs and not the frequency at which the 1P-RTP rates should be set. The primary reason for setting AARs on annual basis is to align better fluctuations in their fuel cost rate components with the volatile forecasted annual average marginal fuel cost which AARs are designed to recover. The 1P-RTP tariffs are reset on annual basis for the reason of the presence of the fuel cost adjustment component in the FCA. This fuel cost adjustment is predicated on an avoided fuel cost methodology which was replaced with the marginal fuel cost approach under all the other AARs in 2017. With the removal of the fuel cost adjustment component from the 1P-RTP FCA there is no longer a reason to keep this rate as an annually adjusted as all the fuel costs will be recovered under these tariffs through application of hourly marginal fuel costs, which do not require Board's approval, to customers' hourly load.

(c) The benefit of adjusting the 1P-RTP tariff through GRA is one rate less to seek approval for in the AAR application and therefore lesser effort in AAR administration for all parties including the 1P-RTP customers who will not need to be alerted by unnecessary annual revisions to these rates. The proposed approach does not carry any risk to the parties because the fixed costs used in the 1P-RTP rate calculation change only in the GRAs regardless of whether these tariffs are changed annually or once every few years in a GRA. A delay in GRA would only mean that the fixed costs, as set in the previous GRA, would apply for a longer period of time. From that perspective, the 1P-RTP tariffs would be treated in the same manner as many other optional rates such as the ATL TVP tariffs or below-the-line Distribution Tariff and OATT.

(d) No customer took service under the EHV 1P-RTP in 2025. The last time any customers took service under this tariff was in 2005.

Request IR-12:

The Back UpTop-Up Tariff 2026 customer charge is proposed to be increased by 3.25%. NS Power considers this increase to be consistent with the Board's directive in the 2019 AAR Decision.

(a) Please explain how 3.25% was derived as the annual inflation rate.

(b) With reference to Statistics Canada Consumer Price Index, monthly, not seasonally adjusted, Table 18-10-0004-01, please explain how 3.25% is consistent the Statistics Canada inflation rates posted in 2025.

Response IR-12:

(a-b) NS Power's annually adjusted escalation factor of 3.25 percent is higher than Statistics Canada reported rate inflation of 2.2 percent, as reported in October 2025, for a variety of reasons.

The Company's escalation factor reflects more than the cost-of-living adjustments which the rate of inflation is designed to reflect. It also accounts for market competitiveness, merit-based increases, and retention strategies. This approach ensures that employee salaries do not only keep pace with the living expenses but also remain competitive and thus position NS Power to attract and retain talent in a competitive labour market.

Request IR-13:

In Appendix G2 EO

(a) In the tab Generation, what is the difference between Total Generation in row 15 and Total CBL Load in row 17?

(b) Why is CBL Load used for PHP Load in the Cost Summary tab instead of Total Generation?

(c) In the Cost Summary tab in line 35 Total Generation cost by type, with PHP load, why are the values for August to December different from the System Cost tab column BW?

(i) In System Cost tab, what is the Curtailment in column BV representing?

(ii) Please explain the difference between Curtailment base and Curtailment PHP CBL and how they are calculated.

(iii) In the Generation tab, column BP in row 37 contains WACOW ($/MW), please explain this measure and how it is applied.

Response IR-13:

(a) Total Generation and CBL Load differ due to battery losses. The PLEXOS dispatch in the two scenarios will contain different levels of BESS usage and varying battery losses which causes a delta between generation and CBL Load, additional generation is required to serve battery losses.

(b) PHP Load must be the denominator in the calculation of the rate as this is the energy to be metered and billed to the customer. The additional battery losses associated with serving this customer cannot be distinguished from that serving other customers in the reality.

(c) The difference between the rows and columns referenced is the cost of curtailment assigned once the PHP Wind Farm is forecast to be online as described below.

(i) The curtailment costs shown on the System Cost tab represent the forecast cost of additional wind curtailments once the PHP wind farm is online in August 2026.

(ii) In PLEXOS, when more wind is available than can be economically used to serve load, the model will "export" the energy at near zero price. These uneconomic exports are analog for wind curtailments; therefore, the difference in exports between the "no PHP" or Base case and the PHP CBL case are the curtailments associated with serving the PHP CBL load and those costs must be attributed to the CBL rate.

(iii) The quantity of curtailments must be multiplied by a price to determine the cost of additional curtailments. WACOW is an acronym for the Weighted Average Cost of Wind. This is a weighted average price of wind PPAs.

Request IR-14:

In Appendix I EO there are Demand Side Management Cost Recovery Rider Charges. Why are these included as part of the AARs?

Response IR-14:

The Demand Side Management Cost Recovery Rider (DCRR) Charges in Appendix I EO are for information purposes only. They have been filed for the Board's approval in the 2026 DCRR proceeding (M12521).