Nova Scotia Energy Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

M12451

Nova Scotia Power Inc. 2026-2027 General Rate Application

Nova Scotia Power
Compliance Filing

April 7, 2026

CONFIDENTIAL ATTACHMENTS ONLY

TABLE OF CONTENTS

LIST OF FIGURES

1.0 INTRODUCTION

On March 25, 2026, the Nova Scotia Energy Board (NSEB, Board) released its decision in Nova Scotia Power Inc.'s (NS Power, Company) 2026-2027 General Rate Application (GRA). In its decision, the Board directed NS Power to file its compliance filing within two weeks of the date of the decision. As directed at paragraph 736 of the decision, the GRA compliance filing includes the following:

- A further reduction of $8 million in Operating, Maintenance and General (OM&G) Expenses in each of 2026 and 2027 (over and above the $9 million outlined in the Settlement Agreement).
- A reduction in NS Power's proposed executive compensation for 2026 and 2027 consistent with the *Nova Scotia Power Incorporated Regulations*.
- Removal of GRA OM&G costs proposed for deferral and for collection over the 2026-2027 test period.
- Reduction of $1.8 million in fuel and purchased power costs in 2026 to reflect the updated estimate for Maritime Link assessment costs, and an update of the 2027 Maritime Link assessment costs
- Amendment to section 3.2.8 of the Fuel Adjustment Mechanism (FAM) Plan of Administration (POA) as discussed in 2026-2027 GRA NSEB IR-33 and the other proposed amendments to the FAM POA and FAM Tariff.
- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (as referred to in Undertaking U-6).
- Removal of the proposed AMI opt-out fee.

2.0 COMPLIANCE FILING COMPONENTS

In addition to the information specifically addressed below and in the GRA decision, NS Power is providing the following updated documents in support of this compliance filing.

- Appendix A – POA (Clean)
- Appendix B – POA (Redline)
- SR-01 – COSS (Partially Confidential)
  - Attachment 2 – 2026 COSS (Partially Confidential)
  - Attachment 3 – 2027 COSS (Partially Confidential)
  - Attachment 5 – 2026 BCF Allocation (Partially Confidential)
  - Attachment 6 – 2027 BCF Allocation (Partially Confidential)
  - Attachment 7 – 2026-2027 R/C Ratios
  - Attachment 8 – 2026-2027 Rates by Component Tables
  - Attachment 9 – 2026 Unmetered Calculations
  - Attachment 10 – 2027 Unmetered Calculations
  - Attachment 11 – 2026 OATT Rate Development
  - Attachment 12 – 2026 OATT Ancillary Service Costs
  - Attachment 13 – 2027 OATT Rate Development
  - Attachment 14 – 2027 OATT Ancillary Service Costs
  - Attachment 15 – 2026-2027 Distribution Tariff Calculations
- FO-01 – Regulated Statement of Earnings
- FO-02 – Regulated Balance Sheet
- FO-03 – Regulated Statement of Retained Earnings
- FO-04 – Regulated Cash Flows
- FO-05 – Electric Revenue Details (Partially Confidential)
- FO-07 – Fuel and Purchased Power
- FO-08 – OM&G Expenses
- FO-10 – Average Capital and Cost of Capital
- FO-11 – Details of Interest Charge
- FO-12 – Average Rate Base – Capital Assets
- FO-13 – Average Rate Base – Deferred Charges and Credits

- RB-01 – Plant In Service Continuity Schedule
- RB 02-16 – Rate Base Table
- DA-02 - Accumulated Reserve for Depreciation
- DA-03 – Amortization Expense
- OR-01 – Proof of Revenue Calculations
- OR-02 – Miscellaneous Revenues and Special Charges
- OE-01A – Fuel Forecast Attachment 1 and 2 (Confidential)
- OE-01C – Fuel Costs per MWh (Confidential)
- OE-02-09 & 13- OM&G 2026-2027 Financial Outlook
- OE-10-11 – Taxes
- CS-01-03 – Capital Structure and Debt/Equity Ratios
- PR-01 – Proposed Rates (clean and redline)
    - Attachment 1/2A – Domestic Service Tariff
    - Attachment 1/2B – Domestic Service CPP Tariff
    - Attachment 1/2C – Domestic Service TOU Tariff
    - Attachment 1/2D – Domestic Service Time-of-Day Tariff
    - Attachment 1/2E – Small General Tariff
    - Attachment 1/2F – Small General CPP Tariff
    - Attachment 1/2G – Small General TOU Tariff
    - Attachment 1/2H – General Tariff
    - Attachment 1/2I – General CPP Tariff
    - Attachment 1/2J – General TOU Tariff
    - Attachment 1/2K – MURB TOU Tarriff
    - Attachment 1/2L – Large General Tariff
    - Attachment 1/2M – Small Industrial Tariff
    - Attachment 1/2N – Medium Industrial Tariff
    - Attachment 1/2O – Large Industrial Tariff
    - Attachment 1/2P – Municipal Tariff
    - Attachment 1/2Q – Outdoor Recreational Lighting Tariff
    - Attachment 1/2R –Unmetered Service Tariff
    - Attachment 1/2S – Fuel Adjustment Mechanism Tariff
    - Attachment 1/2T – OATT Schedules 1-3, 5-10
    - Attachment 1/2U – Distribution Tariff
    - Attachment 1/2V – Storm Cost Recovery Rider
    - Attachment 1/2W – Demand Side Management Cost Recovery Rider (DCRR)

- PR-03 – Proposed Regulations (clean and redline)
    - Regulation 1.1 Interpretation and Definitions
    - Regulation 5.1 Meter Reading
    - Regulation 7.1 Schedule of Charges

3.0 REVISIONS TO REVENUE REQUIREMENT

3.1 OM&G Reduction

The NSEB determined in section 3.3.1.1 of the GRA decision that there should be a reduction of $8 million in each of the two test years (in addition to the $9 million OM&G reduction contained in the Settlement Agreement). Specifically, at paragraph 102 the Board directed a reduction of $2 million to be applied to the OM&G for each test year for the following groups:

- Reliability Implementation (Energy Delivery)
- Communications and Public Affairs (Corporate Groups)
- Grid Modernization and Customer Integration (Customer Experience and Innovation)
- Corporate Human Resources (Corporate Groups)

The requested adjustment has been made and is reflected in **FO-08** (Operating, Maintenance and General Expenses) and carried through to NS Power's calculation of 2026 and 2027 revenue requirement in other relevant schedules.

3.2 Executive Compensation Adjustment

In section 3.3.2 of the GRA decision, at paragraphs 117-118 the Board confirmed that executive compensation to be recovered in rates cannot exceed 100 percent of the Province's SO5 pay scale for NS Power's Chief Executive Officer and 90 percent for all other executives.

NS Power has made the adjustments to its OM&G as set out on line 9 in **FO-08** (Operating, Maintenance and General Expenses) and this adjustment is carried through to NS Power's calculation of 2026 and 2027 revenue requirement in other relevant schedules. This has reduced revenue requirement by $144,859 in 2026 and $149,204 in 2027.

3.3 Removal of GRA Costs Deferral

NS Power requested a deferral of the GRA and COSS and Line Loss Study costs as part of the GRA. At Section 3.5.1.5.1 of the GRA decision the NSEB denied the deferral of the GRA-related costs other than those relating to the COSS and the Line Loss Study.

The total costs relating to the COSS and Line Loss Study are $671,685. The removal of the GRA-related costs is reflected in **DA-03** (Regulatory Amortizations). As directed in paragraph 361 of the decision, NS Power has removed the $1 million of GRA Deferral amortization expense and included an amortization expense of $0.3 million in each year under the heading of COSS & Line Loss Study.

3.4 Fuel and Purchased Power

NS Power requested approval of base cost of fuel (BCF) amounts of $927.3 million in 2026 and $850.9 million in 2027. In section 3.2.1.1 at paragraph 58 of the GRA decision the Board directed NS Power to reduce 2026 revenue requirement by $1.8 million to reflect the updated Maritime Link assessment costs arising from the collection of amounts owing on the $500 million Federal Loan Guarantee. The Board also directed NS Power to update the 2027 Maritime Link assessment costs (to be reflected in the 2027 BCF amounts).

NS Power has removed $1.8 million from the 2026 revenue requirement and $1.7 million from the 2027 revenue requirement. Please refer to **FO-07** (Details of Fuel and Purchased Power). The revised 2026-2027 fuel rate percentage changes are included in **Figure 1** and **Figure 2** below.

Figure 1- 2026-2027 Fuel Rate Percentage Changes without Smoothing

Customer Class	2026	2027
Residential	0.7	0.7
Small General	1.9	0.4
General	2.1	(0.4)
Large General	1.7	(1.6)
Industrial		
Small	3.6	(0.7)
Medium	1.8	(2.1)
Large Industrial		
Firm Transmission Service	1.9	(2.0)
Firm Distribution Service	1.8	(1.9)
Interruptible Transmission Service	2.1	(2.3)
Interruptible Distribution Service	2.0	(2.1)
Large Industrial Total	2.0	(2.1)
Municipal	9.0	0.6
Unmetered	1.0	(0.7)
Total	1.3	0.1

Figure 2 - 2026-2027 Fuel Rate Percentage Changes with Smoothing

Customer Class	2026	2027
Residential	1.3	(0.6)
Small General	2.6	(0.9)
General	3.2	(2.8)
Large General	3.3	(5.1)
Industrial		
Small	4.5	(2.8)
Medium	3.5	(6.0)
Large Industrial		
Firm Transmission Service	3.6	(5.9)
Firm Distribution Service	3.4	(5.6)
Interruptible Transmission Service	4.3	(7.2)
Interruptible Distribution Service	4.0	(6.8)
Large Industrial Total	4.1	(6.8)

Customer Class	2026	2027
Municipal	9.5	(0.5)
Unmetered	(0.2)	1.6
Total	2.2	(1.7)

Based on the two-year BCF forecast, NS Power is applying for an average 2.2 percent annual increase in FAM customer rates in 2026 and a reduction of 1.7 percent in 2027.

3.5 Addition of Maritime Link Transmission Assets to Rate Base

At paragraphs 374-375 of the GRA decision, the Board noted that NS Power met the test for inclusion of the Maritime Link transmission projects in rate base, and that inclusion of the projects in rate base is only effective on a go-forward basis. The Board specifically said at paragraph 375, "To be clear, the amount to be included in rate base for these projects is the net book value of these assets as of the date of the Board's Order in this matter."

NS Power originally proposed that the Maritime Link transmission assets be added to the regulated Property, Plant & Equipment (PP&E) balance as of January 1, 2026. This change will be made as of the date of the Board's Order and the date rates are in effect, assumed to be April 30, 2026, for the purpose of including in revised revenue requirement. This amendment results in a reduction to NS Power's opening 2026 rate base balance and a corresponding reduction in depreciation expense to be included in rates for 2026. These changes have been reflected in **RB-1** (Capital Continuity Schedules) and **FO-12** (Capital Assets) and carried through to other relevant schedules for calculation of NS Power's 2026 rate base and revenue requirement. .

3.6 FAM Plan of Administration

3.6.1 **Section 3.2.8**

In the GRA, NS Power proposed changes to the FAM Plan of Administration (POA). At section 3.2.2.3 of its GRA decision, the Board approved the changes to s. 3.2.8 of the FAM POA as discussed in NSEB IR-33.

For clarity, section 3.2.8 of the FAM POA has been amended as follows:

> Independent Power Producer (IPP) Purchases (e.g. Wholesale Market Non-Dispatchable Spill Tariff) IPP, COMFIT production bonuses and penalties and costs associated with renewable energy programs (e.g. on-bill credits for community solar programs) when such costs cannot be recovered from program participants.

3.6.2 Other POA Amendments

At section 3.2.2.3 of its GRA decision, the Board also approved all other amendments to the POA (i.e. updated NSEB references, removal of specific test period references, updates to calculation of the FAM rate, treatment of load migration between FAM and non-FAM classes, inclusion of ash haulage in solid fuel costs, Tufts Cove wharf / buoy chain inspection and maintenance costs, updates to emission compliance costs, variable production costs, and removal of the FAM calendar of events) proposed in the GRA.

Redline and clean versions of the updated FAM POA are attached to this compliance filing as **Appendix A** and **Appendix B**.

3.7 Cost-of-Service Adjustments

The NSEB accepted NS Power's proposed cost-of-service (COS) changes and the cost-of-service studies (COSS). However, at paragraph 584 the Board directed NS Power to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs.

With respect to the load carrying capability adjustment, the NSEB directed at paragraph 626 of its decision that NS Power implement at load carrying capability adjustment of 0.4 kW/customer to the minimum system method in the compliance filing.

The load carrying capability adjustment of 0.4 kW/customer has been included in the following COSS exhibits: **SR-01 Attachments 2 and 3,** Exh 3c, Exh 3e, Exh 3g and Exh 9b. Please also refer to Undertaking U-6 for a detailed discussion of changes made by NS Power in these exhibits.

3.8 Updates to Miscellaneous Charges and Regulation Changes

In section 3.10 of the GRA decision at paragraph 685, the Board approved the revisions to the Schedule of Charges, with the exception of the AMI opt-out fee. At paragraph 684 the Board directed NS Power to address the removal of the AMI opt-out fee in the compliance filing. Please refer to **OR-02**- Miscellaneous Revenues and Special Charges which reflects the removal of the AMI opt-out fee from Other Revenue. References to the AMI opt-out fee have been removed from the relevant regulations and schedule of charges as noted below.

Please refer to **PR-03** for the clean and redline versions of the following updated regulations:

- Regulation 1.1 – Interpretation and Definitions
- Regulation 5.1 – Meter Reading
- Regulation 7.1 – Schedule of Charges

These updated versions reflect the removal of references to the AMI opt-out fee.

3.9 Amendments Arising from GRA IR Process

In CA IR-1, IG IR-1, and Renewall IR-7, NS Power advised that it would address specific items as part of the GRA compliance filing.

CA IR-1 contained the following response from NS Power:

> This change to the interruptible credit, reflective of a reduction by 8,000 kW in the interruptible coincident peak of PHP, represents a reduction in the annual credit provided to PHP of approximately $0.9 million in 2026 and $0.8 in 2027. Further, the correction of the power factor from 1.02 to 10.6 in 2027, discussed in part (e) below, has a partially offsetting effect of $0.2 million, bringing the net reduction to $0.6 million in 2027. The above changes will have a small downward effect on costs of service of other rate classes once re-distributed in the COSS. The company proposes to incorporate this update as part of the Compliance filing following the issuance of a Board Decision.
>
> …
>
> The revenue redistribution effect of the change to the distribution adder is contained within the LIR class. To the extent the distribution cost adder went down, the base cost energy and demand charges of the LIR went up. As a result, the overall decrease to the distribution-connected LIR customers is about $0.1 million per year and is matched by a parallel increase to the transmission-connected LIR customers. The company proposes to incorporate this update as part of the Compliance filing following the issuance of a Board Decision.

NS Power confirms that the updated COSS reflects the changes arising from the interruptible credit, and that the revenue redistribution effect of the distribution adder has been incorporated into the compliance standardized filings.

In response to IG IR-1, NS Power made the following commitment:

> In preparing this response the Company found an error in its Distribution Cost Adder (DCA) calculations. Instead of using the distribution system costs of $1.717 million in 2026 and $1.791 million in 2027, as apportioned to the Large Industrial (LI) Rate in the filed 2026 and 2027 COSS spreadsheets, the Company has used a dated distribution cost input of $1.932 million. The revised DCA is $2.073 per kVA in 2026, which represents a 27 percent increase over the current DCA of $1.632per

> kVA, and $2.244 per kVA in 2027, which represents an 8 percent increase over the 2026 DCA. Please refer to Attachment 1 for calculations of the revised 2026 and 2027 DCAs.
>
> …
>
> Subject to the Board's approval, the Company proposes to make the appropriate revision to the DCA in the Compliance Filing, consistent with the revised rate calculations included in response to CA IR-1, following the Board's Decision on the GRA.

NS Power confirms that the revision to the DCA is reflected in the COSS attachments to Compliance SR-01.

Renewall IR-7 contained the following commitment:

> Within the RTR market, NS Power service to customers is governed by the Distribution Tariff, which includes the Distribution Tariff Rates (DTR) as Appendix A. Until recently, the Distribution Tariff has only included provisions for RTR Distribution-connected customers. Within the GRA,[1] the Company has expanded the DTR to include service to RTR Transmission-connected customers. It was an oversight to not make accompanying revisions to the main body of the Distribution Tariff. To address this, pending a Board determination with respect to the proposed changes to the DTR, the Company proposes to update the Distribution Tariff, to align with the proposed DTR revisions, in the Compliance Filing to follow the GRA Decision.

NS Power confirms that this update has been made to the Distribution Tariff included as part of this compliance filing, as described below in Section 3.10.4.

3.10 Tariff Revisions

In addition to the changes in rates described in Section 3.11, certain of the Company's tariffs reflect revisions to tariff language or provisions proposed in the Application. In addition, and in the time

[1] Please refer to Section 13.10 of the Direct Evidence.

since the September 2025 Application, five of these tariffs have been amended through other proceedings. Further clarification is provided for each, as set out in the following sections.

Please note that the FAM and DCRR amounts contained in **OR-01** Proof of Revenue, and associated sheets, have remained unchanged since the original GRA filing. The SCRR rate in OR-01 Proof of Revenue represents actual 2025 SCRR in 2025, no SCRR in 2026, and assumes no SCRR in 2027. The rates included in the Tariff sheets (provided in **PR-01 Attachments 01A to 02W**) reflect the rates for 2026 and 2027, including the recently approved 2026 DCRR amounts, as described in Section 3.10.2.

3.10.1 Fuel Adjustment Mechanism (FAM) Tariff

On December 18, 2025, NS Power applied for approval to extend the existing FAM Actual Adjustment (AA) and Balance Adjustment (BA) riders on an interim basis. The FAM BA rider (M11393) was set to collect the $117 million receivable on behalf of Invest Nova Scotia, while the FAM AA rider (M11902) was set to temporarily recover the first year of costs related to the Federal Loan Guarantee (FLG) through the Maritime Link Assessment, pending an application by the Company to reset its BCF. On December 23, 2025, the Board approved the continuation of "existing FAM AA and BA riders on an interim basis, effective January 1, 2026, until further order of the Board, or as ordered in NS Power's ongoing general rate application and its 2026 FAM AA/BA rider application."[2]

As provided in this compliance filing, FLG costs are incorporated into the BCF and no longer require collection through the FAM AA rider. Collection of the $117 million receivable on behalf of Invest Nova Scotia will continue to be administered through the FAM BA rider until fully collected. Therefore, the FAM Tariff included in this compliance filing removes the FAM AA rider amounts which reflected the balance of the $500 million Maritime Link FLG and, consistent with the FAM Tariff provided in the GRA, retains the BA amounts for continued collection of the $117 million.

Further, in preparing the compliance filing FAM Tariff, the Company determined that the "Unmetered" rates were unintentionally excluded from the 2026 and 2027 Rate tables in the FAM Tariff sheet. However, these charges were, and are, included in the Rate Schedules provided in **SR-01 Attachment 8**, and is in the proof of revenue calculations provided in **OR-01 Attachment 1**. This has been corrected in the compliance filing FAM Tariff which is provided as **PR-01 Attachments 01S** (beginning on PDF page 62) and **02S** (beginning on PDF page 185).

[2] M12640 – Board Order, 326791, page 2.

3.10.2 DSM Cost Recovery Rider (DCRR)

On March 31, 2026, the Board issued its Order approving the 2026 DCRR (M12521) effective January 1, 2026. The DCRR Tariff has been updated to reflect the 2026 rates and the revised method for allocating system costs using the new cost-of-service study, as approved in M12521. The Tariff also reflects the BA_1 and BA_2 revisions as proposed and approved in the GRA, subject to the Board Order on this compliance filing. The implementation of rate changes in NS Power's billing systems is a multi-step process (e.g. updating rate amounts, quality assurance, testing) that typically requires a few weeks to complete. As further rate changes will be required following the Board's Order on the GRA, NS Power intends to implement both DCRR and GRA rate changes in its billing system such that both changes are reflected on customer bills at the same time. NS Power believes this approach is in customers' best interest as it avoids the need for two separate and proximate rate increases. Any true-up required as a result of the differences between the 2025 DCRR and 2026 DCRR amounts collected between January 1, 2026 and the date of the Board's Order in this proceeding will be addressed in the BA component of the DCRR in a future DCRR Application. The tariff is included as **PR-01 Attachments 01W** (beginning on PDF page 109) and **02W** (beginning on PDF page 247).

To keep class rate impact calculations consistent with those applied in the Application, NS Power did not update the DCRR charges for the M12521 Order in rate tables included in 2026-2027 GRA **SR-01 Attachment 01** (Compliance) and Proof of Revenue calculations included in 2026-2027 GRA **OR-01 Attachment 01 EO** (Compliance).

3.10.3 Time-Varying Pricing (TVP) Tariffs

In October 2025, NS Power sought approval to temporarily modify the Domestic, Small General, and General Critical Peak Pricing (CPP) and Time-of-Use (TOU) Tariffs for the 2025/26 TVP Season due to the cyber incident which affected system functionalities required to administer the Tariffs. Pursuant to the Board's Order (M12499), NS Power amended the CPP and TOU Tariffs, introducing an Interim Energy Charge which reflects the applicable standard offer rate until system functionality is restored. The 2026 CPP and 2026 TOU Tariff Interim Energy Charge has been updated to reflect the applicable standard offer rates to take effect upon the date of the Board's Order in this proceeding. The CPP Tariff Energy Charges to be applied effective November 1, 2026 and January 1, 2027, respectively, reflect the CPP rates for Critical and Non-Critical Peak Hours. The TOU Tariff Winter Period Energy Charges to be applied effective November 1, 2026 and January 1, 2027, respectively, reflect the TOU rates for Winter Peak and Off-peak Periods. The TOU Tariff Non-winter Period Energy Charge to be applied effective April 1, 2027 reflects the TOU rates for the Non-winter Period. All other charges in these Tariffs are made effective upon the date of the Board's Order for 2026 and January 1, 2027. These tariffs are included as **PR-01 Attachments 01B** (beginning on PDF page 3) and **02B** (beginning on PDF page 115)**, PR-01 Attachments 01C** (beginning on PDF page7) and **02C** (beginning on PDF page 119)**, PR-01 Attachments 01F** (beginning on PDF page 15) and **02F** (beginning on PDF page 128)**, PR-01 Attachments 01G** (beginning on PDF page 19) and **02G** (beginning on PDF page 132)**, PR-01 Attachments 01I** (beginning on PDF page 24) and **02I** (beginning on PDF page 138)**,** and **PR-01 Attachments 01J** (beginning on PDF page 28) and **02J** (beginning on PDF page 142)**.** The Multi-unit Residential Building Pilot TOU Tariff was not modified in M12499 and is found at **PR-01 Attachment 01K** (beginning on PDF page 32) and **02K** (beginning on PDF page 146).

3.10.4 Distribution Tariff

Further to the commitment NS Power made in response to Renewall IR-7 (noted in Section 3.9), the main body of the Distribution Tariff reflects the extension of Board-approved service provisions to potential RTR transmission-connected customers. The Distribution Tariff Rates are contained in Appendix A to the tariff. The Distribution Tariff is found at **PR-01 Attachments 01U** (beginning on PDF page 84) and **02U** (beginning on PDF page 212).

3.10.5 Storm Cost Recovery Rider (SCRR)

At section 4.2 of the GRA decision the NSEB approved the proposed continuation of the Storm Rider pilot for the GRA test period with the change to include the added symmetrical component. At paragraph 699 of the decision the Board noted that the 2026 and 2027 SCRR rider values are set at zero. To update the Tariff from what was included with the original GRA filing in September

2025, NS Power has removed the “Rates for 2025” table from the SCRR Tariff, and the Tariff now only includes the “Rates for 2026” table. The SCRR Tariff is included in **PR-01 Attachments 01V** (beginning on PDF page 107) and **02V** (beginning on PDF page 244).

3.11 Rate Changes

Standardized filing **FO-9** includes the revenue requirement and rate increase breakdown. For ease of reference, that information is provided below. The standardized filing FO-9 in the GRA referred to three figures in the Application (11-1, 14-2 and 14-3).

Figure 3 - 2026-2027 Breakdown of Forecast Revenue Requirement by Category

Category	**2026 ($ Million)**	**2027 ($ Million)**
Fuel & Purchased Power	916.8	916.6
OM&G	343.7	349.8
Demand Side Management Expense	63.8	63.8
Depreciation and Accretion	282.1	300.8
Taxes (including grants-in-lieu of property taxes)	29.6	55.9
Regulatory Amortization (including FAM expense)	16.1	(2.4)
Interest and Other Expenses (including AFUDC and FAM interest)	118.5	130.1
Return on Equity	200.4	212.0
Revenue Requirement	1,971.0	2,026.5
Other Revenue	44.8	46.2
Revenue Requirement from Electric Rates	1926.2	1980.4

Figure 4 – 2026 Rates (Compliance)[3]

Proposed Rate Changes	Units	Current 2025	Proposed for 2026	Percent Change
Domestic Service Tariff				
Customer Charge	$/mo.	19.17	20.08	4.8%
Energy Charge	¢/kWh	17.928	18.480	3.1%
DSM Rider	¢/kWh	0.633	0.648	2.3%
Small General Tariff				
Customer Charge	$/mo.	21.28	22.00	3.4%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	18.474	19.075	3.3%
Energy Charge (Block 2)	¢/kWh	16.748	17.268	3.1%
DSM Rider	¢/kWh	0.753	0.729	-3.2%
General Tariff				
Demand Charge	$/kW	10.554	9.809	-7.1%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.977	14.989	0.1%
Energy Charge (Block 2)	¢/kWh	11.680	11.925	2.1%
DSM Rider	¢/kWh	0.646	0.749	16.0%
Large General Tariff				
Demand Charge	$/kVA	13.845	11.174	-19.3%
Energy Charge	¢/kWh	11.507	11.322	-1.6%
DSM Rider		0.790	0.458	-42.0%
Small Industrial Tariff				
Demand Charge	$/kVA	8.332	7.496	-10.0%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	13.873	13.976	0.7%
Energy Charge (Block 2)	¢/kWh	11.299	11.660	3.2%
DSM Rider	¢/kWh	0.753	0.555	-26.3%
Medium Industrial Tariff				

[3] The Energy Charge reflects a total of the smoothed base cost charge, SCRR, and the FAM AA/BA Riders. NS Power has maintained the FAM AA/BA riders consistent with this Application, as described in Section 3.10.1. 2026 DSM Riders have been updated to reflect Board's DCRR Order M12521.

Demand Charge	$/kW	13.796	10.710	-22.4%
Energy Charge	¢/kWh	11.044	10.888	-1.4%
DSM Rider	¢/kWh	0.314	0.479	52.3%
Large Industrial Tariff				
Demand Charge	$/kVA	12.601	9.268	-26.5%
Interruptible Credit	$/kVA	(7.486)	(7.638)	2.0%
Distribution Cost Adder	$/kVA	1.632	2.161	32.4%
Energy Charge (Firm- Transmission)	¢/kWh	10.799	10.542	-2.4%
Energy Charge (Firm -Distribution)	¢/kWh	10.836	10.542	-2.7%
Energy Charge (Interruptible - Transmission)	¢/kWh	10.776	10.558	-2.0%
Energy Charge (Interruptible - Distribution)	¢/kWh	10.813	10.558	-2.4%
DSM Rider	¢/kWh	0.431	0.663	53.8%
Municipal Tariff				
Demand Charge	$/kVA	13.428	11.248	-16.2%
Energy Charge	¢/kWh	10.658	11.705	9.8%
DSM Rider	¢/kWh	0.627	0.265	-57.7%

Figure 5 – 2027 Rates (Compliance)[4]

Proposed Rate Changes	**Units**	**Proposed for 2026**	**Proposed for 2027**	**Percent Change**
Domestic Service Tariff				
Customer Charge	$/mo.	20.08	21.04	4.8%
Energy Charge	¢/kWh	18.480	19.223	4.0%
DSM Rider	¢/kWh	0.648	NA	NA
Small General Tariff				
Customer Charge	$/mo.	22.00	22.73	3.4%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	19.075	19.952	4.6%
Energy Charge (Block 2)	¢/kWh	17.268	17.950	4.0%

[4] The Energy Charge reflect a total of smoothed base cost charge, SCRR and FAM AA/BA riders. NS Power has maintained the FAM AA/BA riders, as described in Section 3.10.1,consistent with this Application. 2026 DSM Riders have been updated to reflect Board's DCRR Order M12521. The 2027 DSM Riders are unknown at this point and have been marked as Not Available (NA).

DSM Rider	¢/kWh	0.729	NA	NA
General Tariff				
Demand Charge	$/kW	9.809	10.697	9.1%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.989	15.039	0.3%
Energy Charge (Block 2)	¢/kWh	11.925	11.698	-1.9%
DSM Rider	¢/kWh	0.749	NA	NA
Large General Tariff				
Demand Charge	$/kVA	11.174	11.989	7.3%
Energy Charge	¢/kWh	11.322	10.781	-4.8%
DSM Rider	¢/kWh	0.458	NA	NA
Small Industrial Tariff				
Demand Charge	$/kVA	7.496	8.143	8.6%
Energy Charge (Block 1, first 200 kWh)	¢/kWh	13.976	13.939	-0.3%
Energy Charge (Block 2)	¢/kWh	11.660	11.424	-2.0%
DSM Rider	¢/kWh	0.555	NA	NA
Medium Industrial Tariff				
Demand Charge	$/kW	10.710	11.269	5.2%
Energy Charge	¢/kWh	10.888	10.147	-6.8%
DSM Rider	¢/kWh	0.479	NA	NA
Large Industrial Tariff				
Demand Charge	$/kVA	9.268	10.006	8.0%
Interruptible Credit	$/kVA	(7.638)	(7.667)	0.4%
Distribution Cost Adder	$/kVA	2.161	2.327	7.7%
Energy Charge (Firm- Transmission)	¢/kWh	10.542	9.956	-5.6%
Energy Charge (Firm -Distribution)	¢/kWh	10.542	9.956	-5.6%
Energy Charge (Interruptible - Transmission)	¢/kWh	10.558	9.912	-6.1%
Energy Charge (Interruptible - Distribution)	¢/kWh	10.558	9.912	-6.1%
DSM Rider	¢/kWh	0.663	NA	NA
Municipal Tariff				
Demand Charge	$/kVA	11.248	12.226	8.7%
Energy Charge	¢/kWh	11.705	11.849	1.2%
DSM Rider	¢/kWh	0.265	NA	NA

A breakdown of the average increases per customer class is set out below in **Figure 6.**

Figure 6 – 2026 – 2027 Proposed Rate Impacts (Percentage Change)

Customer Class	2026	2027
Domestic Service		
Fuel	1.3	(0.6)
Non-Fuel	1.8	4.5
Total	**3.1**	**3.9**
Small General		
Fuel	2.6	(0.9)
Non-Fuel	0.4	4.8
Total	**3.0**	**3.8**
General		
Fuel	3.2	(2.8)
Non-Fuel	(3.7)	3.8
Total	**(0.5)**	**1.0**
Large General		
Fuel	3.3	(5.1)
Non-Fuel	(8.3)	2.6
Total	**(4.9)**	**(2.5)**
Small Industrial		
Fuel	4.5	(2.8)
Non-Fuel	(5.2)	3.6
Total	**(0.7)**	**0.8**
Medium Industrial		
Fuel	3.5	(6.0)
Non-Fuel	(10.3)	1.9
Total	**(6.9)**	**(4.0)**
Large Industrial Firm Transmission Service		
Fuel	3.6	(5.9)
Non-Fuel	(10.3)	2.4
Total	**(6.7)**	**(3.4)**
Large Industrial Firm Distribution Service		
Fuel	3.4	(5.6)
Non-Fuel	(9.6)	2.7

Total	**(6.2)**	**(3.0)**
Large Industrial Interruptible Transmission Service		
Fuel	4.3	(7.2)
Non-Fuel	(11.9)	2.7
Total	**(7.6)**	**(4.5)**
Large Industrial Interruptible Distribution Service		
Fuel	4.0	(6.8)
Non-Fuel	(12.2)	3.3
Total	**(8.2)**	**(3.4)**
Large Industrial Total		
Fuel	4.1	(6.8)
Non-Fuel	(11.7)	2.9
Total	**(7.6)**	**(3.9)**
Municipal Class		
Fuel	9.5	(0.5)
Non-Fuel	(8.2)	3.6
Total	**1.3**	**3.1**
Unmetered Classes		
Fuel	(0.2)	1.6
Non-Fuel	7.7	4.7
Total	**7.5**	**6.2**
Total FAM Classes		
Fuel	2.2	(1.7)
Non-Fuel	(1.0)	4.2
Total	**1.2**	**2.5**

4.0 BILLING DIRECTIVE

The Board's Decision includes the following:

> [731] The Board understands that before the implementation of AMI meters, the implementation of a new rate in the middle of a billing cycle might mean that the bill for that period would need to be prorated. However**, it is not clear to the Board why any bill rate change needs to be prorated if an AMI meter is used. As the Board understands it, an AMI meter would be able to precisely determine the amount of energy used before a new rate came into effect and after the new rate came into effect. In such circumstances, the Board would expect the approved rates at the time the energy is consumed would be used.**
>
> [732] **Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase,** the Board directs that the bills covering the time that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used.
> [**emphasis added**]

The Board is correct that the accumulation of customer electricity consumption across the day and throughout the year, as enabled by AMI, provides a foundation to "precisely determine the amount of energy used before a new rate came into effect and after the new rate came into effect".

However, the calculation of customer bills occurs within the legacy Customer Information System (CIS). While the CIS utilizes the time differentiated data complied within the AMI system, the CIS relies on a single starting meter read and a single ending meter read to calculate a customer's bill. Current practice involves taking the number of days in a billing period and prorating the new and old rates based on the number of days before and after the rate change. To apply different prices to actual consumption before and after the effective date of the rate change would require the creation of additional and irregular bill periods within CIS and the application of the old and new rates to these new bill periods. In addition, there are numerous systems and processes that rely on the current structure of bill periods. Even if possible, inserting a new interim bill period would create known and unknown issues.

If even possible, the complexity and broad scope of issues faced to undertake the types of changes that would be required to the CIS billing system would involve those set out below. The Company anticipates that such a process would require a minimum of 6 months.

- Within the CIS, there are more than 250 variations of the rate structures included in NS Power tariffs. These accommodate a variety of billing scenarios within each customer class such as cadence (bi-monthly/monthly/seasonal), special credits (i.e. transformer ownership), peak/off-peak periods and net metering vs. self-generation.
- The bill print program alone contains over 10,000 lines of code and 10–15 sub-programs.
- This code supports all customer bills, and any changes to it require careful design, testing, and deployment because they carry a risk of unintended impacts across the entire customer base.
- Additionally, the specialized resources required to modify this code are the same personnel maintaining the legacy CIS and preparing for its replacement. Redirecting them to interim changes would duplicate effort and cost, as similar work would need to be repeated during the modernization project.
- Changes to the billing calculation methodology within the CIS would require review and potential revisions to key financial controls under the Company's compliance programs.
- The required additional bill periods would lead to additional bills generated and mailed. As 40% of the Company's customers are still receiving paper bills by mail, this translates to approximately $200,000 in additional OM&G costs for each additional bill period.
- Additional billing periods and/or split billing periods could impact other systems that rely on such data. The MyEnergy Insights tool, for example, provides personalized energy usage and billing notifications to customers by comparing bill periods that are expected to be of equal durations.

Revision to billing processes for implementing changes in electricity prices requires care. However, for changes arising from GRAs, which have the potential to affect all classes of customers and the entire customer base, particular care is required. To attempt to introduce multiple billing dates, as would be required to apply different prices within the same billing period, would be a fundamental change to the CIS billing process. If this were indeed possible within the current CIS, it would require creation of a team with expertise in this area, extensive development and extensive testing prior to implementation. Such an undertaking would involve significant cost and significant risk for customers.

In comparison, the proration methodology that exists in the NS Power CIS is well-tested and produces a reasonable approximation of the cost effect of rate increases applied to customer consumption before and after the effective date of the rate change. The Company understands the proration methodology is common electric utility practice, including for utilities with AMI.

NS Power understands the Board's desire for more precise application of rate changes. As the Board is aware, work is currently underway at NS Power to replace its legacy CIS system, and, subject to the foregoing, the replacement system may provide an opportunity to achieve more precise implementation of rate changes. As part of the development of the CIS replacement project, the Company will undertake to assess the feasibility of adding the functionality required to apply changes to rates across billing periods to actual customer consumption. Until this work is completed and the associated capital project is brought before the NSEB for the Board's approval, the Company proposes to retain the existing proration methodology.