



PUBLIC REDACTED VERSION

Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2024 – 2025

Report to the Nova Scotia Energy Board

Prepared by Bates White, LLC

August 3, 2026

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Abbreviations

AA	Actual Adjustment	ERM	Enterprise Risk Management group (Emera)
AGC	Automatic Generation Control		
AGT	Algonquin Gas Transmission	ERMC	Enterprise Risk Management Committee (Emera)
ASTM	American Society for Testing and Materials	ETRM	Energy Trading and Risk Management software
BA	Balancing Adjustment	FAM	Fuel Adjustment Mechanism
BCF	Base Cost of Fuel	FERM	Fuels Energy and Risk Management
CAD	Canadian dollar	F&PP	Fuel and Purchased Power
CER	Canadian Energy Regulator	FST	Fuel Strategy Table
COMFIT	Community Feed in Tariff	FT	firm transportation
COMSOLAR	Solar for Community Buildings Program	GHG	greenhouse gases
CO ₂	carbon dioxide	HFO	heavy fuel oil
COO	chief operating officer	Hg	mercury
CROC	Credit Risk Oversight Committee	IPP	independent power producer
CT	combustion turbine	IRP	Integrated Resource Plan
DAFOR	de-rated adjusted forced outage rate	ISDA	International Swaps and Derivatives
DCZ	Drain Cooling Zone	IT	information technology or interruptible transportation
DR	demand response	LFO	light fuel oil
DSM	Demand-Side Management	LNG	liquefied natural gas
ECC	Energy Control Centre	LRT	Load Retention Tariff
EE	energy efficiency	LSH	low-sulphur, high Btu
EFOR	Equivalent Forced Outage Rate	McF	thousand cubic feet
EIA	US Energy Information Administration	M&NE	Maritimes and Northeast Pipeline
ELI	extra-large industrial	MNITMR	minimum revenue interruptible transport
ELIADC	Extra Large Industrial Active Demand Control Tariff	MT	metric tonne
EPIA	Electricity Plan Implementation (2015) Act	MTM	mark-to-market
		MVAR	mega volt ampere reactive power

MW	megawatt	PI	Process Information
MWh	megawatt-hour	PNGTS	Portland Natural Gas Transmission System
NAESB	North American Energy Standards Board	POA	FAM Plan of Administration
NBEM	New Brunswick Power Energy Marketing	PPA	power purchase agreement
NBP	New Brunswick Power	PRB	Powder River Basin
NBP-SO	New Brunswick Power System Operator	REC	Renewable Energy Certificate
NERC	North American Electric Reliability Corporation	RFP	request for proposal
NO _x	nitrous oxide	ROA	Record of Approval
NPCC	Northeast Power Coordinating Council	RSP	Rate Stability Period
NSEB	Nova Scotia Energy Board	RTED	real time economic dispatch
NSPI	Nova Scotia Power, Inc.	SAE	Statistically Adjusted End-Use
NSPSO	Nova Scotia Power System Operator	SCADA/EMS	Supervisory Control and Data Acquisition/Energy Management System
NSR	Net System Requirement	SO ₂	sulphur dioxide
NSUARB	Nova Scotia Utility and Review Board	SOEP	Sable Offshore Energy Project
NYMEX	New York Mercantile Exchange	SWG	FAM Small Working Group
OEM	original equipment manufacturer	TCPL	TransCanada Pipeline
O&M	operating and maintenance	TGP	Tennessee Gas Pipeline
OM&G	operating, maintenance, and general	Tidal FIT	developmental tidal feed in tariff
OTC	over the counter	TSR	total system requirement
PAC	power-activated carbon	USD	United States dollar
PH	Port Hawkesbury	VaR	value at risk
PHB	Port Hawkesbury Biomass	VOM	variable operation and maintenance costs
PHP	Port Hawkesbury Paper	WACC	weighted average cost of capital

I. Introduction and Background

Bates White Economic Consulting (“Bates White”)¹ appreciates the opportunity to serve the Nova Scotia Energy Board (NSEB, or “the Board”) as its independent consultant tasked with providing an audit of Nova Scotia Power, Inc.’s (NSPI’s) Fuel Adjustment Mechanism (FAM) for the period January 1, 2024, through December 31, 2025 (“Audit Period”). This report provides the results of our audit (“Audit Report”).

I.A. Brief Background on Nova Scotia Power, Inc.

NSPI, operating as a privatized company since 1992, provides 95% of the generation, transmission, and distribution of electricity in Nova Scotia.² NSPI has approximately 2,200 employees and serves approximately 550,000 residential, commercial, and industrial customers.³ NSPI controls over \$4.3 billion of assets, which consists in part of approximately 2,400 MW of generating assets and 32,000 kilometers of transmission and distribution lines.⁴ NSPI’s major facilities can be seen in Figure I-1.

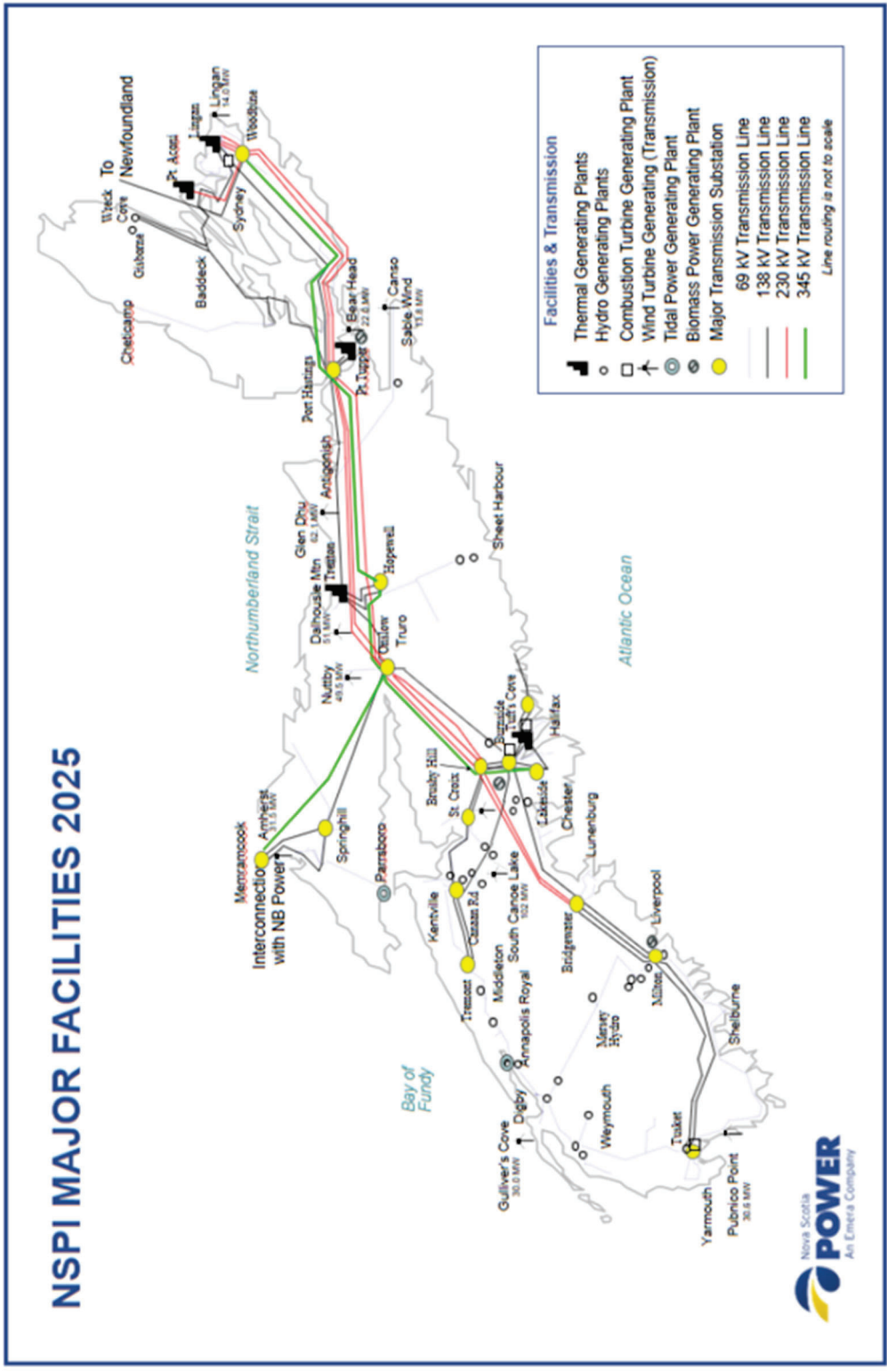
¹ Bates White is an economic consulting firm offering services to law firms, Fortune 500 companies, and government agencies. Founded in 1999 and headquartered in Washington, DC, we have been recognized by *The Washington Post* as a Top Workplace, named a Top 50 Consulting Firm by Vault, and cited as a Top 21 Economics Firm by Global Competition Review.

² Emera, “Nova Scotia Power,” Available at <https://www.emera.com/companies/regulated-electric/nova-scotia-power>

³ Nova Scotia Power, “Who We Are: At A Glance,” Available at <https://www.nspower.ca/about-us/who-we-are>

⁴ Nova Scotia Power, “Who We Are: At A Glance,” Available at <https://www.nspower.ca/about-us/who-we-are>

Figure I-1: NSPI's Major Facilities (2025)⁵



⁵ 2025 10-Year System Outlook NS Power, Nova Scotia Energy Board in the Matter of *The Public Utilities Act*, R.S.N.S. 1989, c.380, Figure 21.

NSPI is a wholly owned subsidiary of Emera Inc. (“Emera”), a diversified energy and services company with approximately 2.7 million customers⁶ and \$45 billion in assets.⁷ Emera’s reportable segments include (a) other regulated electric utilities including Tampa Electric, the Barbados Light & Power Company, Grand Bahama Power Company, and a partial ownership interest in St. Lucia Electricity Services, (b) a 100 percent ownership interest in NSP Maritime Link Inc., which developed the Maritime Link Project (“Maritime Link”), and a 50 percent interest in Wasoqonatl Transmission Incorporated, (c) multiple gas utilities in Canada and the U.S., (d) Emera Energy, which consists of Emera Energy Services, Brooklyn Power Corporation, and a 50 percent interest in Bear Swamp Power Company, a pumped hydro storage project, as well as (e) other insurance, financing, and technology subsidiaries.⁸

⁶ Emera, “About Us,” available at: <https://www.emera.com/about-us>.

⁷ Emera, “As-Reported Financials,” available at: <https://investors.emera.com/financials/as-reported-financials/default.aspx>.

⁸ Emera Q1 2025 Financial Statements, March 31, 2025, pages 8 to 9, available at: https://s205.q4cdn.com/781121964/files/doc_earnings/2025/q1/supplemental-info/Emera-Q1-2025-Financial-Statements.pdf.

I.B. The Fuel Adjustment Mechanism

The FAM is the cost recovery mechanism by which NSPI recovers the cost of fuel and purchased power from its customers. According to NSPI, the cost of fuel and purchased power is its largest expense in providing electricity to customers. Over the Audit Period, NSPI incurred approximately \$1.6 billion in fuel and purchased power costs: in 2024, costs totaled \$509.2 million;⁹ in 2025, the total costs were \$1.065 billion.¹⁰ The total FAM cost over the Audit Period, excluding the benefit associated with a \$485 million Federal Loan Guarantee,¹¹ was approximately \$2.06 billion. These FAM costs are passed through directly to customers.

The FAM is intended to allow NSPI to recover the exact amount of FAM costs from ratepayers without the need for a general rate case. To do so, the FAM rate has three components: (1) the Base Cost of Fuel (“BCF”); (2) the Actual Adjustment (“AA”); and (3) the Balancing Adjustment (“BA”). The BCF is the test year forecast of fuel costs that are incorporated into customer rates by calculating the fuel cost component of customer electricity rates.¹² Historically, the BCF is reset every two years or, alternatively, in the course of any general rate application.¹³

Since the BCF is based on forecasts, there will always be differences between the FAM costs recovered via the BCF and the actual FAM costs that NSPI incurs. These differences accumulate each month in the FAM as either a regulatory asset (if NSPI under-recovers its actual fuel costs) or as a regulatory liability, if NSPI over-recovers its actual fuel costs.¹⁴ To ensure NSPI recovers only its actual FAM costs exactly, a true-up is necessary. To true up the costs, recoveries from or refunds to ratepayers are determined via two adjustments—the AA and BA—which change each year.¹⁵ As explained by NSPI:

The AA represents the difference in the current year between the amount actually spent on fuel and the fuel-related revenue actually recovered from customers. At year end, the under- or over-recovered amount (plus the applicable interest) will be the total FAM deferral amount for that year. For purposes of establishing customer fuel rates to recover or return the FAM deferral amount, NSPI files an application which includes 12 months of actual fuel data (October to September).

⁹ NSPI Q4 2024 FAM Report 3(3).

¹⁰ NSPI Q4 2025 FAM Report 3(3).

¹¹ December 2024 Monthly Report Transmittal Letter, Table 3.

¹² NSUARB, “Decision,” In the Matter of a hearing into Nova Scotia Power Incorporated’s Base Cost of Fuel Reset and Fuel Forecast Standardized Filing for 2011 Fuel Adjustment Mechanism, NSUARB-P-887(2), November 18, 2010, page 6.

¹³ NSUARB, “Decision,” In the Matter of an application by Nova Scotia Power Incorporated for Approval of its 2020-2022 Fuel Stability Plan, NSUARB 165-M09288, December 6, 2019, page 6.

¹⁴ NSPI, “2020-2022 Fuel Stability Plan Application,” June 27, 2019, page 21, lines 26-29.

¹⁵ 2016 FAM BCF Application, page 8, lines 11 to 17.

This total deferral amount is divided by the upcoming year's sales forecast in order to determine the AA rate.

...

The BA represents the difference in the prior year between the actual fuel costs and the fuel-related revenue recovered from customers. As noted above, although the FAM AA calculation uses 12 months of actual data so a balancing adjustment is no longer required to true up the actual costs of fuel during the year...the BA comprises previously deferred FAM amounts and any residual amount of the AA related to previous years not fully refunded or recovered by the AA. The BA rate is established using the cumulative under- or over-recovery divided by forecast sales for the period. Residual BA at the end of a year is applied to the following year and is used in the determination of future BA rates. In this way, only actual costs are recovered from customers.¹⁶

Again, in a typical FAM rate cycle, the BCF would be set for a two-year period, while the AA and BA adjustments would be reset annually to make sure that FAM recovery exactly equaled FAM expenditures over that two-year period. However, on December 18, 2015, the Province enacted the Electricity Plan Implementation (2015) Act (EPIA), which required NSPI to “apply to the Board for approval of a Fuel Stability Plan that sets the amount customers will pay for fuel for...2017, 2018, and 2019,” which is referred to as the “Rate Stability Period.”¹⁷ On March 7, 2016, NSPI filed its Fuel Stability Plan with the Board, which specified an average annual increase in FAM customer rates of 1.3% in each year of the Rate Stability Period,¹⁸ which the Board accepted on July 19, 2016.¹⁹ The Board noted that, while the AA and BA adjustment process would not occur annually during the Rate Stability Period, NSPI’s “[a]ctual fuel costs will be tracked during the duration of the Fuel Stability Plan and trued up at the end of the Rate Stability Period, which ends December 31, 2019.”²⁰

In 2019, near the end of the Rate Stability Period, NSPI applied and received approval to set BCF rates for the 2020-2022 period, which were approved by the Board in December 2019.²¹ In that proceeding, the Board approved BCF rates for 2020 through 2022.²² The BCF rates were based on forecasted total fuel and purchased power costs for 2020, 2021, and 2022.²³ NSPI referred to this three-

¹⁶ NSPI, “2020-2022 Fuel Stability Plan Application,” June 27, 2019, page 22-23.

¹⁷ NSUARB, “Decision,” In the Matter of a hearing into Nova Scotia Power Incorporated’s 2017–2019 Fuel Stability Plan and Base Cost of Fuel Reset under the Fuel Adjustment Mechanism as required under the Electricity Plan Implementation (2015) Act, M07348, July 19, 2016 [hereinafter “2016 Board BCF Decision”], paragraph 3.

¹⁸ 2016 Board BCF Decision, paragraph 5.

¹⁹ 2016 Board BCF Decision, paragraph 60.

²⁰ 2016 Board BCF Decision, paragraph 5.

²¹ Nova Scotia Utility and Review Board, Decision, M09288, December 6, 2019 (“2019 FSP Order”).

²² The Board also made findings related to the AA and BA adjustments and riders.

²³ 2019 FSP Order, page 11.

year period as a “Fuel Stability Period,” because it applied fixed, smoothed BCF rates for the full period for FAM customers. The AA and BA adjustments have continued to operate annually to reconcile any imbalances in fuel and purchased power cost recovery.

In 2022, NSPI submitted a general rate application which introduced a new “Rate Stability Plan” of 2022 through 2024. The Rate Stability Plan, which received Board approval in February 2023, called for recovery of FAM costs pursuant to specified, “smoothed” annual rate increases over the 2022-2024 period, with the AA and BA adjustments being deferred until 2025.²⁴

The specific costs allowed to be recovered through the FAM include (1) natural gas;²⁵ (2) solid fuel;²⁶ (3) heavy fuel oil (“HFO”);²⁷ (4) diesel oil;²⁸ (5) light starter oil;²⁹ (6) fuel—additives;³⁰ (7) fuel—limestone;³¹ (8) purchased power;³² (9) fuel biomass;³³ (10) fuel—mercury sorbent;³⁴ (11) grid sales

²⁴ NSUARB, “Decision,” M10431, February 2, 2023, paragraphs 19-21.

²⁵ This includes (1) natural gas consumed; (2) financial instruments used for hedging (including gains, losses, fees and interest charges); (3) pipeline reservation fees, tolls, penalties (such as imbalance charges); (4) pipeline losses; and (5) natural gas storage fees. See section 3.2.1 of the FAM Plan of Administration (POA).

²⁶ This includes (1) inventoried costs, such as commodity costs (coal, petroleum coke), financial instruments used for hedging (including gains, losses, fees and interest charges), third-party quality testing and sampling, and transportation costs (e.g., by rail, barge, vessel, truck etc.), including loading, unloading, dispatch, demurrage, port fees, draft surveys, and marine service fees; (2) costs directly applied, including third-party handling, transportation (e.g., movement between Long-Term Dead Storage/Bear head and plants) and maintenance related to coal piles, storage fees (e.g., lease, handling fees, facility fees), environmental compliance fees (e.g., provincial air emissions fees), rail car costs (e.g., lease, repair, maintenance), and international pier operating and maintenance costs; (3) costs expensed through the Plant Fuel Handling Adjustment (i.e., expenses incurred up until the point of the reclaim hopper), including NSPI labour and associated costs for equipment operators, mechanics, supervisors related to fuel handling and lab techs related to testing, costs associated with measurement of inventory (e.g., surveys density testing), non-capital materials for fuel handling (e.g., tools, replacement parts for machines), repair costs for fuel handling equipment and infrastructure, heavy equipment operating costs for fuel handling (e.g., rental and fuel), and Point Tupper Marine Terminal operating and maintenance costs. See section 3.2.2 of the FAM POA.

²⁷ This includes (1) HFO/bunker fuel consumed; (2) financial instruments used for hedging (including gains, losses, fees and interest charges); (3) quality testing and inventory measurement costs; (4) standby emergency response services; (5) third-party supervision of unloading; and (6) transportation costs (e.g., rail, barge, vessel, truck, etc.) including loading, unloading, dispatch, demurrage, port fees, draft surveys, and marine service fees. See section 3.2.3 of the FAM POA.

²⁸ This includes (1) diesel commodity consumed, (2) transportation costs, and (3) quality testing and inventory measurement costs. See section 3.2.4 of the FAM POA.

²⁹ This includes (1) light fuel oil (LFO) commodity consumed, (2) transportation cost, and (3) quality testing and inventory measurement costs. See section 3.2.5 of the FAM POA.

³⁰ This includes additives and transportation costs. See section 3.2.6 of the FAM POA.

³¹ This includes (1) limestone and related transportation; (2) limestone ash hauling and equipment rentals; (3) limestone royalties; and (4) water royalties. See section 3.2.7 of the FAM POA.

³² This includes (1) independent power producer (IPP) purchases (e.g., Wholesale Market Non-Dispatchable Spill Tariff) and IPP and Community Feed in Tariff (COMFIT) production bonuses and penalties; (2) COMFIT purchases; (3) developmental tidal feed in tariff (“Tidal FIT”) purchases; (4) import power purchases and associated fees (e.g., transmission tariffs and losses); (5) renewable energy credits; and (6) financial instruments used for hedging (including gains, losses, fees and interest charges). See section 3.2.8 of the FAM POA.

³³ This includes (1) biomass commodity consumed; (2) maintenance and operating expenses for fuel handling (allocation between operating, maintenance, and general (OM&G) and FAM); (3) third-party quality testing and inventory management costs (e.g., surveys, density testing, sampling); (4) storage fees (e.g., lease, handling fees, facility fees); (5) environmental compliance including Silviculture Fees and harvest audits; and (6) transportation costs (e.g., by barge, truck etc.). See section 3.2.9 of the FAM POA.

³⁴ This includes (1) additives—power activated carbon (PAC) and calcium chloride; (2) transportation costs; and (3) costs

revenue;³⁵ (12) natural gas revenue;³⁶ (13) miscellaneous revenue and recoveries;³⁷ (14) foreign exchange;³⁸ (15) limited-duration fuel testing;³⁹ and (16) below-the-line costs.⁴⁰

I.C. The FAM Audit Scope

The FAM audit is provided for in the FAM Plan of Administration. Specifically, the FAM POA states:

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently.⁴¹

The Board has previously and clearly defined the prudence standard to be applied in the FAM Audit:

The standard for determining prudence of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, 'prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made...Hindsight is not applied in assessing prudence...A utility's decision is prudent if it was within the range of decisions reasonable persons might have made...The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.'⁴²

The POA specifies that the Board will use "a qualified independent firm [to] conduct the audit," which will "address the financial and management/performance aspects of NSPI's fuel procurement and

relating to an Hg (mercury) diversion program that the Minister of Environment approved under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended. See section 3.2.10 of the FAM POA.

³⁵ This includes any revenue from power exports net of any transmission tariffs and losses; this includes renewable energy credits arising out of the sale of renewable energy in the New England market. See section 3.2.11 of the FAM POA.

³⁶ This includes any revenue from the resale of natural gas. See section 3.2.12 of the FAM POA.

³⁷ This includes revenues from joint partnerships in wind farms, other fuel-related miscellaneous revenues, steam sales to Port Hawkesbury Paper, and steam sales at the Trenton generating station. See section 3.2.13 of the FAM POA.

³⁸ This includes adjustments to record expenses or revenues denominated in foreign currencies and includes the gain or loss on currency hedges entered into for the purpose of fuel procurement. See section 3.2.14 of the FAM POA.

³⁹ This includes fuel testing costs (including solid fuel, liquid, and additives such as PAC) and consists of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third-party testing and analysis), only to the extent incurred as part of limited duration test burns occasionally made by NSPI, limited to non-capital costs. See section 3.2.15 of the FAM POA.

⁴⁰ This includes spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff and fuel costs incurred in providing service under the Wholesale Market Backup/Top-Up Service Tariff, less revenue received under the Wholesale Market Backup/Top-Up Service Tariff net of non-fuel items. See section 3.2.16 of the FAM POA.

⁴¹ FAM POA, section 5.0.

⁴² NSUARB, "Decision," In the Matter of a hearing into Nova Scotia Power Incorporated's Fuel Adjustment Mechanism Audit for the years 2014 and 2015, M07611, December 21, 2016, paragraph 13, citing 2005 NSUARB 27, paragraph 84.

recovery under the FAM.”⁴³ The audit will review “the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period.”⁴⁴ The POA explains the objectives and scope of the audit as follows:

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power’s procurement as described in the NS Power Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power’s conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):

- Fuel and purchased power costs
- Review of overall operational availability and capacity factor for the generating fleet
- Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
- Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
- Review all Fuel and Purchased Power contracts executed by NS Power and NSPEMI for the period under review for prudence and for compliance with the Fuel Manual
- Review of NS Power’s use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments⁴⁵

In addition to those topics specifically identified in the FAM POA, the Board also tasked us with reviewing NSPI’s transactions with its affiliates for compliance with the Affiliate Code of Conduct. We

⁴³ FAM POA, section 5.0.

⁴⁴ FAM POA, section 5.0.

⁴⁵ FAM POA, section 5.0.

also conducted a follow-up to NSPI's response to the 2020-2021 FAM Audit recommendations. We include discussion of these items in each chapter, as applicable.

I.D. Our Methodology and Process

Bates White's approach to the audit was to compile a record of information obtained from NSPI through formal data requests, phone interviews, online demonstrations, online sensitive document review, site visits, and conference calls. We issued formal data requests, reviewed numerous contracts for FAM-related products and services and conducted numerous conference calls and interviews with key personnel at NSPI (onsite and virtually), including management and operations personnel that are responsible for fuel and power procurement, sales, and supply management. From the record of evidence we compiled, we also conducted independent quantitative analysis using NSPI-provided data. Our report's findings, conclusions, and recommendations are based on that record of information.

The FAM POA requires the fuel auditor to “[c]onduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring.”⁴⁶ In this Audit Period, we visited NSPI generating stations (Tufts Cove, Port Hawkesbury Biomass, and Trenton), the Point Tupper Marine Terminal and Bear Head facilities, and the NSPI headquarters in Halifax in May 2026.

Our audit had a specific, defined scope of work. We focused on NSPI's practices, procedures, and processes for FAM-related items. We did not audit NSPI's operations outside of its fuel and power procurement processes, nor its compliance with reliability standards. Further, while we sampled hundreds of transactions for FAM-recoverable products and services for prudence, we did not review every FAM-recoverable transaction that NSPI made over the Audit Period.

As we have noted in past audit reports, NSPI remained cooperative and responsive throughout the audit process. NSPI accommodated our requests to interview dozens of specific NSPI employees; to review NSPI's models and software tools; and to receive countless contracts, reports, invoices, and other forms of supporting documentation requested throughout the audit process. NSPI staffed the audit with sufficient resources to provide a consistent, logical interface with our audit team and to provide information in a reasonable timeframe. NSPI also used a secure document sharing platform (SharePoint) to allow for efficient sharing of documents that served as a reliable record of documents provided to date throughout the process.

⁴⁶ FAM POA, section 5.0.

I.E. Structure of this Report

Our report proceeds as follows. We have fourteen substantive chapters, each addressing a different aspect of our scope of work—and NSPI’s FAM-related activities:

- Chapter II—Organization, Staffing, and Controls
- Chapter III—Forecasting and Fuel Supply Planning
- Chapter IV—Solid Fuel Procurement and Contracts
- Chapter V—Solid Fuel Supply Management
- Chapter VI—Biomass Procurement and Supply Management
- Chapter VII—Natural Gas Supply Planning
- Chapter VIII—Natural Gas Procurement
- Chapter IX—Fuel Oil Procurement and Management
- Chapter X—Power Plant Performance
- Chapter XI—Commitment and Dispatch
- Chapter XII—Power Purchases and Sales
- Chapter XIII—Hedging
- Chapter XIV—FAM Accounting
- Chapter XV—ELIADC

We note that Chapter XIV (FAM Accounting) was primarily authored by BDO USA, P.C. (“BDO”), with Bates White providing review. We also note that all currency figures in this report are Canadian dollars (“CAD”), unless otherwise noted.

Each chapter has the same structure. Each begins with a **Background** section, which provides contextual information useful for understanding the chapter. Next is the **Findings** section, which contains our factual records, evidence, and analysis. This is always the longest of the sections, as it serves as the factual basis for the next two sections. The next section is the **Conclusions** section, which includes our distilled deductions and judgments on NSPI’s FAM-related activities during the Audit Period. This section is particularly important for readers to review, as it provides our view of what NSPI is doing well and what can be done better. Last is the **Recommendations** section, which contains our action items for NSPI to address to improve outcomes for FAM customers.

I.F. Summary of Recommendations

Below are our forty-two (42) audit recommendations. To provide at least some context for these recommendations, we include the directly related conclusion(s) on which the recommendations are based. To fully understand our basis for these recommendations, please refer to the full respective chapters for our complete findings.

II - Organization, Staffing, and Controls

Conclusion II-10: The NSPI Risk Manual's current language regarding risk management organization is partially outdated, as it indicates delegation of risk responsibilities within Emera and NSPI to personnel that no longer have that responsibility. NSPI indicated that it would update the specifics of risk delegation for both NSPI and Emera in the next Fuel Manual update. **(Recommendation II-1)**

Recommendation II-1: NSPI should ensure its next Fuel Manual update revises the NSPI Risk Manual, as necessary, to make accurate references to risk management authority delegations at both NSPI and Emera.

Conclusion II-14: NSPI's December 2025 internal audit addressing the hedging process was found to be "Acceptable" and contained no recommendations. However, NSPI noted that the audit scope was limited to assessing processes to manage and monitor hedging activities by management and to test effectiveness of the hedging portfolio, and that the underlying analysis could not be opined upon because detailed support was unavailable as a result of the cyber event. This was a reasonable conclusion, given the lack of data access. However, in our view, it will be important for the internal audit team to complete this audit to the extent it can when data access is restored. **(Recommendation II-2)**

Recommendation II-2: NSPI should complete its December 2025 internal audit of NSPI's hedging program as soon as practicable and to the extent possible.

III - Forecasting and Fuel Supply Planning

No recommendations.

IV – Solid Fuel Procurement

Conclusion IV-20: NSPI uses current index futures prices to evaluate index-priced solid fuel supply offers and does not add a risk premium associated with those bids when evaluating them against fixed-priced offers. This is a reasonable approach and NSPI should continue to allow suppliers flexibility in making offers, including index-priced offers. Still, an index-priced bid is subject to change and could get more or less expensive if the index price rises. NSPI hedges its [REDACTED] index exposure through derivative contracts, which is a credible way to reduce exposure to index price variations, but hedging has costs and is subject to risk of unexecuted hedges due to market price movements as the hedging procurement process takes its course. We include a recommendation that NSPI consider a method to account for index price risk when evaluating index priced offers against fixed price alternatives, without sacrificing the benefits of allowing suppliers to offer index-priced bids. **(Recommendation IV-1)**

Recommendation IV-1: NSPI should consider a method to account for index price risk when evaluating index priced offers against fixed price alternatives in its solid fuel procurement process, without sacrificing the benefits of allowing suppliers to offer index-priced bids.

Conclusion IV-21: The results of NSPI's October 2025 petcoke RFP were reasonable, though did result in a suboptimal contract clause. As offered, winning supplier [REDACTED] would deliver its supply between "December 1, 2025 and December 31, 2026," with the delivery schedule to be "mutually agreed upon between Buyer and Seller." In the final executed contract, the delivery schedule made no reference to the as-bid delivery period, only noting that [REDACTED] would propose a planned delivery date by December 31, 2025 and that NSPI would use commercially reasonable efforts to accommodate the schedule. This open-ended delivery schedule language is suboptimal and should be avoided in future supply agreements.

(Recommendation IV-2)

Recommendation IV-2: NSPI should take steps to ensure fuel supply contracts have specified delivery periods, and that those periods match offers received from suppliers, unless in allowing for flexibility in contract language specifying delivery periods and terms, NSPI receives compensation through other more favorable rates, terms, or conditions within the negotiated final supply agreement.

Conclusion IV-24: First, NSPI failed to invite all relevant suppliers to participate in its October 2024 trucking RFP, including [REDACTED] the economic bidder in the December 2023 trucking RFP. This is a material lapse in practice from a team that ordinarily maximizes use of competition and good practices. It cannot be known what would have occurred in the RFP process had others been invited, though note [REDACTED] price offer was lower than [REDACTED] in all trucking RFPs held during the Audit Period. (We include a recommendation to reduce the likelihood of such lapses in the future.) This led to the selection of [REDACTED] which underperformed both in delivering required volumes and in meeting safety standards. However, our review of inventory data suggests [REDACTED] underperformance had no direct incremental costs to FAM customers. Moreover, once the [REDACTED] contract was awarded pursuant to the October 2024 RFP, NSPI acted prudently by (1) tracking [REDACTED] performance under the contract, (2) issuing a supplemental trucking RFP quickly upon observing [REDACTED] poor performance, (3) administering the supplemental RFP in a reasonable manner and selecting the most economic offer, (4) terminating [REDACTED] contract upon repeated safety violations, (5) allowing [REDACTED] to provide a safety mitigation plan and executing a new, lower risk contract with [REDACTED] (which again, was lower cost than [REDACTED] and (6) maximizing the volumes delivered by [REDACTED] (~39,000 tonnes vs. a contract maximum of 40,000 tonnes), not [REDACTED] (11,714 tonnes). We therefore do not recommend any disallowances associated with these contracts. **(Recommendation IV-3)**

Recommendation IV-3: NSPI should introduce a process to ensure all suitable vendors are invited to relevant RFPs.

Conclusion IV-29: NSPI's decisions regarding rail line maintenance, including its decision to fund track maintenance on the coal spur (despite no contractual obligation to do so), were reasonable and supported by credible evidence. Costs incurred matched work purchase orders with vendors. However, NSPI's reliance on Purchase Orders (as opposed to contracts) for its \$[REDACTED] in [REDACTED] transactions is an outlier from NSPI's normal and common practice for its suppliers of FAM-related products and

services. The Purchase Orders contain key protections for NSPI and their customers and incorporate “NSPI Standard Terms and Conditions,” which are appended to the Purchase Orders. However, these “standard” terms and conditions make specific references to the purchase order itself, anticipating that key details of a transaction will be specified there. In the case of the [REDACTED] Purchase Orders, there was not always a reference to key aspects of the work, such as its timing or full scope. This can subject NSPI and FAM customers to additional risk. We include a recommendation that NSPI institute a process to ensure that Purchase Orders include key information that is required in NSPI’s Standard Terms and Conditions. **(Recommendation IV-4)**

Recommendation IV-4: NSPI should institute a process to ensure that Purchase Orders include key information that is required in NSPI’s Standard Terms and Conditions.

V – Solid Fuel Supply Management

Conclusion V-16: On October 6, 2025, there was a derailment of five railcars of a northbound, 21-car coal train on the Sydney Coal Railway connecting the International Pier to the Lingan generating station. While NSPI owns the Sydney Coal Railway, it contracts with [REDACTED] for the operation of the railway, including “preventative, breakdown and capital maintenance” of the railway. Upon derailment, [REDACTED] retrieved spilled coal volumes and addressed all cleanup and restoration efforts at no cost to NSPI. While the derailment did not impose costs on NSPI, the findings of [REDACTED] review and [REDACTED] conclusions demonstrate that there is room for improvement in the inspection and maintenance of the Sydney Coal Railway. While [REDACTED] is already at work on identifying and implementing those improvements, it would be prudent of NSPI to ensure that the improvements are being carried out and that [REDACTED] conclusions have also been considered by [REDACTED] in its improvement efforts. Besides safety and environmental impacts, derailments can also disrupt NSPI’s fuel supply chain. We therefore recommend that NSPI track [REDACTED] progress in implementing these improvements, including any implied by [REDACTED] inspection report. **(Recommendation V-1)**

Recommendation V-1: NSPI should track [REDACTED] progress in implementing improvements following the October 6, 2025 derailment on the Sydney Coal Railway line, including any implied by [REDACTED] inspection report.

Conclusion V-20: In the third quarter of 2024, NSPI discovered an error in the Trenton 5 coal blend, which caused NSPI’s assumptions about the fuel mix being consumed by Trenton 5 to be incorrect back to the fourth quarter of 2023. The error caused an overstatement of mid-sulfur and LSL coal consumption, an understatement of LSH consumption, and understated Trenton 5 heat rates. NSPI addressed this error by making adjustments to inventory and consumption data in the third quarter of 2024. The implication for this error is that heat rates have been incorrectly stated for Trenton 5, at minimum, and potentially Trenton 6 and Point Tupper in historical FAM reports. We include a recommendation that NSPI correct any reported heat rate data for these three units since the fourth quarter of 2023. **(Recommendation V-2)**

Recommendation V-2: NSPI should correct any previously-reported heat rate data for Trenton 5, Trenton 6, and Point Tupper that were impacted by incorrect assumptions about the fuel mix consumed by Trenton 5 from the fourth quarter of 2023 to the third quarter of 2024.

VI – Biomass Procurement and Supply Planning

Conclusion VI-8: Given the low turnout to the June 2024 biomass supply RFP, NSPI could improve its RFP process by removing the stated preference for biomass supply contracts with terms that are not less than two years and specify the time period(s) of NSPI's biomass supply need. **(Recommendation VI-1) (Recommendation VI-2)**

Recommendation VI-1: NSPI should consider revising future biomass supply RFPs to reduce or remove preference for supply contracts of 2-years or greater, given the inability or unwillingness of suppliers to offer such terms and the potential negative impact this preference may have on participation.

Recommendation VI-2: Future biomass supply RFPs should specify the time period(s) of its biomass supply need for which it is inviting offers.

Conclusion VI-10: Some of NSPI's executed contracts lacked execution dates. **(Recommendation VI-3)**

Recommendation VI-3: NSPI should ensure that its FAM-related contracts include execution dates from their signatories.

Conclusion VI-14: We have four concerns with the energy balance process. First, the "Step 1" moisture target, which is set at a fixed ■%, is rigid, and that rigidity could lead to outcomes that unduly favor (or disfavor) PHP, relative to FAM customers. Second, the "Step 2" moisture target is subject to a "collar" (floor and ceiling values) that should be reconsidered. Third, the energy balance process allows PHP to carry "negative" balances on its ledger with NSPI indefinitely and penalty-free. Fourth, the price of chips applied to PHP chip deficits under the energy balance process when PHP's chip deficit exceeds the chip volumes delivered by PHP (such that NSPI burns chips from other suppliers to serve PHP's industrial demand) should be clarified to reflect the actual cost of the chips consumed on PHP's behalf.

(Recommendation VI-4) (Recommendation VI-5) (Recommendation VI-6) (Recommendation VI-7)

Recommendation VI-4: NSPI should consider ways to revise "Step 1" of the energy balance process in specifying a target moisture content that accounts for the dynamism in PHB's relative economics and the biomass fuel supply realities in the province to prevent instances of unduly high or low payments by PHP.

Recommendation VI-5: NSPI should consider relaxing or removing the moisture target "collar" in "Step 2" of the energy balance process.

Recommendation VI-6: NSPI should consider an enhancement to capture the time value of PHP bark deficits determined under the energy balance process that carry over into future months.

Recommendation VI-7: NSPI should consider ways to clarify the price of chips applied to PHP chip deficits under the energy balance process when PHP's chip deficit exceeds the chip volumes delivered by PHP (such that NSPI burns chips from other suppliers to serve PHP's industrial demand) to better reflect the actual cost of the chips consumed on PHP's behalf.

Conclusion VI-20: In the aftermath of the cyber event, when NSPI did not have access to Aligné Fuels, NSPI did not conduct any biomass inventory adjustments in order to avoid making any adjustments until it had access to Aligné to avoid the need for any retroactive changes. Once it regained access, NSPI applied a Q4 2025 inventory adjustment. NSPI stated that the Q4 2025 adjustments were pending as they had not yet been agreed to by PHP, noting that due to the codification of the energy balance process, "retroactive adjustments" were made to 2024 and 2025 results. (**Recommendation VI-8**)

Recommendation VI-8: NSPI should update the Board with the results of its effort to reconcile biomass inventory adjustments and energy balance results in Q4 2025 that carried over to 2026.

VII – Natural Gas Supply Planning

Conclusion VII-1: NSPI does not appear to have completed the analyses made in Recommendation VII-1 from the previous FAM audit, which recommended that "[t]his quantification should include a quantification of risk mitigation strategies including, but not limited to, reselling gas, releasing capacity, and various rate levels and contract terms." (**Recommendation VII-1**)

Conclusion VII-2: NSPI evaluated FT contract opportunities and explicitly excluded any quantification of risk mitigation strategies, resulting in the opportunities not being pursued to the possible detriment of FAM customers. (**Recommendation VII-1**)

Recommendation VII-1: NSPI should conduct the analysis described in Recommendation VII-1, that was accepted by NSPI, from the 2022 – 2023 FAM Audit.

Recommendation VII-2: NSPI should re-do its analysis of the Freeport FT capacity offer reflecting the following: use of the same assumptions and price forecasts for the 10-year term starting November 1, 2029, explicitly including the value of cost mitigation strategies (e.g., sales of unneeded gas, AMA, etc.) using unneeded existing FT capacity and Freeport FT capacity, allowing the existing FT capacity to expire at term, and calculating the NPV of the net costs from November 2029 through October 2039 using the discount rate of the FAM customers.

Recommendation VII-3: NSPI should formalize a written draft of the ERM position on FT capacity, as described in VII.B.2.h. and in NSPI's response to DR 6-9, and provide it for review by the Board and FAM stakeholders. In generating that document, NSPI should clearly identify

who (FAM customers, NSPI, or others) bears the risk of over-paying for unneeded longer-term FT capacity and why, and who currently pays to mitigate that risk by paying for spot gas.

VIII – Natural Gas Procurement

Conclusion VIII-6: NSPI has adequately addressed our natural gas procurement-related recommendations from the 2022-2023 Audit Report but note that a portion of Recommendation VIII-5 regarding the evaluation of reducing gas purchases appears to remain outstanding. **(Recommendation VIII-1)**

Recommendation VIII-1: Provide monthly documentation of gas sales by NSPEMI and NSPI (excluding transactions between NSPEMI to NSPI) identifying the terms (e.g., quantity, location, price, etc.) of the transaction, why the counterparty was selected, how the price was agreed to, and why a particular title transfer location was selected.

IX – Fuel Oil Procurement and Management

No recommendations.

X – Power Plant Performance

Conclusion X-14: NSPI completed and provided ten Root Cause Analyses with another four reported in progress. The completed Root Cause Analyses contained recommendations that NSPI adopted, many of which NSPI has implemented, with 27 recommendations in progress. NSPI should provide the Board an update on the status of these recommendations at the end of 2026. **(Recommendation X-1)**

Recommendation X-1: NSPI should provide the Board an update on the status of the remaining 27 recommendations from the Root Cause Analyses at the end of 2026.

Conclusion X-17: A November 22, 2024 forced outage event at Tufts Cove 2 due to elevated vibration levels followed a planned maintenance outage. The Root Cause Analysis found that (1) several rotor blades exhibited a loss of welding material at the shroud-to-blade attachment points and (2) significant deposits were observed on the underside of the blades. The Root Cause Analysis concluded that the most probable cause of the elevated vibration was machine imbalance caused by under-blade deposits not fully removed during the planned outage. As a result of this issue, Tufts Cove 2 was offline from November 22, 2024 through January 6, 2025. When asked if it had estimated the incremental FAM cost of this outage, NSPI indicated that it did not conduct this calculation. We recommend NSPI provide an estimate of the incremental FAM costs incurred during this event. **(Recommendation X-2)**

Recommendation X-2: NSPI should provide its estimate of the FAM and non-FAM costs associated with the November 22, 2024 forced outage at Tufts Cove 2 due to elevated vibration levels.

Conclusion X-19: A March 7, 2024 forced outage event at Burnside 1, which occurred when the unit tripped due to high vibration, was caused by a liberated turbine blade. The subsequent investigation determined that the engine, which was purchased by NSPI from the OEM (Wood Group Pratt & Whitney) as a refurbished engine in 2021, had not been refurbished using industry best practices prior to delivery to NSPI. The engine was out of service until December 1, 2024, though a leased engine was installed and operated from July 24, 2024 until the replacement engine was received and installed on December 1, 2024. NSPI negotiated a settlement with the OEM worth \$ [REDACTED] USD in avoided costs of engine refurbishment and the leased engine. When we requested NSPI's estimate of the FAM costs associated with this event, NSPI indicated that it did not conduct this calculation. NSPI further noted that the leased engine allowed Burnside 1 to remain operational during the time the refurbished engine was out of service, avoiding displacement of generation to higher-cost resources. We agree with this point, at least for the period when the leased engine was in place (July 2024-December 2024). However, there was a period where the unit was fully offline, prior to receipt of a leased engine (March 8, 2024-July 24, 2024). It is unlikely this event resulted in significant incremental FAM costs, as Burnside 1 is a high-cost peaking unit rarely operated. Given the nature of this event, however, NSPI should confirm that no incremental FAM costs were incurred, and if they were, to refund those costs to customers, who should bear no costs associated with this event. **(Recommendation X-3)**

Recommendation X-3: NSPI should provide its estimate of the FAM costs associated with the March 7, 2024 forced outage at Burnside 1 and ensure that FAM customers bear no incremental costs for this outage.

Conclusion X-22: On October 26, 2024, Point Tupper was forced offline in an outage that would last 552.37 hours until November 18, 2024 due to a generator trip on under-excitation protection. The trip was traced to a failure within the rotating brushless exciter assembly, specifically involving damage to rectifier diodes and associated fuses. Subsequent inspection identified carbon and dirt accumulation on the exciter components, which contributed to electrical arcing across an insulator and the resulting component failures. Following the event, NSPI has updated the frequency of preventative maintenance to annually as an additional precaution and noted the OEM's suggestion that an engineering study could be performed to validate cleanliness improvements that may be achieved by installing baffles. Given the impact of outages like these, we include a recommendation that NSPI complete its corrective measures and update the Board with an explanation of the measures ultimately implemented. **(Recommendation X-4)**

Recommendation X-4: NSPI should update the Board on its corrective measures taken in response to the October 26, 2024 forced outage at Point Tupper by the end of 2026.

Conclusion X-23: Point Tupper experienced a forced outage on June 25, 2023, which lasted until August 2, 2023, in which the plant's two CW pumps tripped due to ground faults at separate times. The cause of the two failures was a combination of contamination and moisture that contributed to the motor failures. The Root Cause Analysis found that "less than ideal moisture management in the operating environmental

for these motors” was present, “[c]abinet heaters were not fully functional on either motor at the time of failure,” and that while “[t]he operating environment is challenging...there are opportunities to improve moisture management.” When we requested NSPI’s estimate of the FAM costs of this event, which kept Point Tupper offline for 38 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so. That calculation should include the impact of the forced outage (which lasted from June 23, 2023 to July 12, 2023), plus the period in which Point Tupper was derated (through August 2, 2023).

(Recommendation X-5)

Recommendation X-5: NSPI should provide its estimate of the FAM costs associated with the June 25, 2023 forced outage at Point Tupper.

Conclusion X-25: PHB suffered a forced outage on May 31, 2024 due to a broken Low-Pressure Steam Extraction Control Valve Rod. The Rod was classified by NSPI as a “critical spare” part by NSPI, and NSPI’s inventory records indicated that one spare Rod was held in inventory at the plant. However, following the event, and despite inventory records to the contrary, NSPI was unable to physically locate the Rod at the plant. Unable to locate the spare Rod, NSPI made the decision to undertake temporary repairs to the failed Rod and initiate procurement of a replacement spare. The broken Rod was repaired and added back to the LP Extraction Control Valve system on June 17, 2024, and the PHB unit was returned to service that same day. The Rod was later replaced during the unit’s annual planned outage. When we requested NSPI’s estimate of the FAM costs of this event, which kept PHB offline for 18 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so, given that the forced outage lasted longer than what it would have been if NSPI had been able to locate the spare Rod in the immediate aftermath of the event. That calculation should include the impact of the forced outage (which lasted from May 31, 2024 to June 17, 2024), plus the cost of repairs to the failed Rod. **(Recommendation X-6)**

Recommendation X-6: NSPI should provide its estimate of the FAM costs associated with the May 31, 2024 forced outage at PHB, plus the costs of repairs to the failed Low-Pressure Steam Extraction Control Valve Rod.

Conclusion X-33: In 2024, NSPI’s GHG emissions were 5.6 mega tonnes and 5.8 mega tonnes in 2025, meeting air quality regulations. NSPI’s total OBPS GHG compliance costs were \$ [REDACTED], though that differs from the \$ [REDACTED] reported by NSPI in its FAM reporting. We include a recommendation that NSPI reconcile this difference. **(Recommendation X-7)**

Recommendation X-7: NSPI should reconcile the difference between the \$ [REDACTED] in total OBPS compliance cost reported in the audit to the \$ [REDACTED] provided in FAM reporting.

XI – Commitment and Dispatch

Conclusion XI-2: The processes that NSPI uses for committing, scheduling, and dispatching units were not changed during the period before the cyber event, January 1, 2024 through April 25, 2025. The concerns that we raised about these processes in prior audit reports remain intact for the 2024-2025 audit period. A new Outage Coordination Solution and Economic Dispatch Optimization Solution is expected to be implemented in 2026. **(Recommendation XI-1)**

Conclusion XI-5: The commitment and scheduling plans, based on least-cost optimization using PortOps, were frequently manually adjusted to incorporate unmodelled constraints, or judgements by marketers or the NSPSO based on knowledge and experience. **(Recommendation XI-1)**

Conclusion XI-11: Low capacity factors of most units in NSPI's fleet may be indicative of potential inefficiencies. More efficient use of existing generation may be possible with the new Economic Dispatch Optimization Solution. **(Recommendation XI-1)**

Recommendation XI-1: NSPI should be required to comply with 2022-2023 Recommendation XI-1 and provide a detailed and comprehensive report that explains how the new functionality in the Economic Dispatch Optimization and Outage Coordination Solutions address (or do not address) the outage, optimization, and dispatch issues identified in the current systems.

Conclusion XI-8: Lingan 2 was kept online after it was called to service for system security reasons for long stretches of time. Once Lingan 2 is brought on line, it is kept online for a period of time to allow thermal stresses to stabilize (typically a week). **(Recommendation XI-2)**

Recommendation XI-2: NSPI should develop a written set of criteria, to be approved by the Board, that must be met to keep Lingan 2 operational once committed. Compliance with these criteria should be used by the Board when approving capital and operating costs for Lingan 2.

XII – Power Purchases and Sales

Conclusion XII-14: NSPI and NLH agreed that all undelivered volumes *during the Audit Period* were Block A volumes. However, the parties remain in dispute regarding classification of 61.2 GWh of “undelivered” Base Block energy that accrued during the August-December 2021 timeframe. NSPI claims that this volume should be considered Block B energy, while NLH argues it should be Block A. While the volumes themselves have long been since redelivered, the classification of these volumes matters. If Block A, NLH has already met its obligations under the ECA. If Block B, NLH owes NSPI “compensation energy” in the form of 120% of the undelivered volumes, or an additional 12.2 GWh, which NSPI values at approximately [REDACTED] million. NSPI provided evidence of negotiations between the parties, but the parties remain at an impasse. Under the ECA, the parties are required to negotiate a solution, and barring that, proceed to mediation. If that fails, the parties either agree to an arbitration procedure or litigation. In our view, NSPI has reasonably pursued this issue and we include a recommendation that NSPI update the Board upon resolution. **(Recommendation XII-1)**

Recommendation XII-1: By the earlier of the resolution of the dispute or the end of 2026, NSPI should update the Board regarding its efforts to recover the value associated with [REDACTED]
[REDACTED]

Conclusion XII-24: In assessing NLH's compliance with the EAA requirement that it make available to NSPI an average of 1.2 TWh per year over the 35-year term of the EAA, NSPI clarified in discussions that it does not consider NLH's annual EAA RFP offers in assessing this metric, but rather considers what is made available to NSPI on a day-ahead basis. This is a highly material point, and we agree with NSPI's interpretation, as it prevents NLH from meeting its average 1.2 TWh/year offer requirement through a high annual EAA offer that can then be pared down later. Still, given the nature of this offer requirement, which is a 35-year average, it would be prudent for NSPI to begin reporting its tracking of NLH's compliance with this requirement. To that end, we include a recommendation that NSPI report in its FAM Annual Report NLH's average Surplus Energy offered to date, as of the end of the most recent EAA contract year. Reporting this to the Board and stakeholders will mitigate the possibility of a surprise contractual dispute later on in the administration of the EAA. **(Recommendation XII-2)**

Recommendation XII-2: NSPI should report in its FAM Annual Report NLH's average Surplus Energy offered to date, as of the end of the most recent EAA contract year.

XIII – Hedging

Conclusion XIII-18: Notwithstanding Conclusion XIII-20, we observed unexecuted hedges in seven out of eight quarters. On average, [REDACTED] days elapsed between the date of the PLEXOS forecast and FST approval. Once traders had approval from the FST, they began transacting almost immediately, executing the first transaction one day after FST approval, on average. Energy markets can change substantially during a [REDACTED]-day period, and prices for financial hedge contracts can increase beyond the range of approved price ranges, increasing the risk of unexecuted hedges. We therefore include a recommendation that NSPI review the timing of its hedging lifecycle – from PLEXOS forecasting, to FST presentation development, to FST approval – to find areas for increased efficiency. **(Recommendation XIII-1)**

Recommendation XIII-1: NSPI should review the timing of its hedging lifecycle – from PLEXOS forecasting, to FST presentation development, to FST approval – to find areas for increased efficiency.

XIV – FAM Accounting

Conclusion XIV-7: NSPI should maintain a detailed listing of invoices included in each payment batch to enhance the audit trail of cash disbursements. The listing should identify the invoices processed, related vendors, payment amounts, payment dates, and batch references to provide a complete audit trail and support management's review of cash disbursements. Maintaining this documentation would strengthen

internal controls, improve payment tracking, and reduce the risk of duplicate or unauthorized payments.
(Recommendation XIV-1)

Recommendation XIV-1: NSPI should maintain a detailed listing of invoices included in each payment batch to enhance the audit trail of cash disbursements. The listing should identify the invoices processed, related vendors, payment amounts, payment dates, and batch references to provide a complete audit trail and support management's review of cash disbursements.

XV – ELIADC

Conclusion XV-2: ELIADC benefits as reported in the ELIADC annual reports are largely composed of the mandatory contribution to fixed costs. **(Recommendation XV-1)**

Recommendation XV-1: In the 2026 ELIADC annual report and all future reports, NSPI should report the amounts collected under the \$4/MWh (or any other) mandatory contribution to fixed costs, but should not characterize this cost recovery as a benefit to FAM customers.

Conclusion XV-9: There is no basis to reduce the penalty charged to PHP for Cause Code 5 PDN deviations (PHP decision to vary from schedule) by █%, an amount equal to \$ █.
(Recommendation XV-2)

Recommendation XV-2: We recommend that PHP be required to pay an additional \$ █ for Cause Code 5 penalties in 2025 and that these amounts be allocated to FAM customers.

Conclusion XV-4: ADC benefits are calculated as the difference between annual forecasted incremental fuel costs (based on forecast load), and actual annual weighted average fuel costs (based on actual load). Changes in fuel prices and load from forecast amounts will distort the ADC benefit calculation which can result in no ADC benefits when they do exist, or positive ADC benefits when they do not. The design of the ADC benefits calculation is deficient. **(Recommendation XV-3)**

Recommendation XV-3: To the extent possible, the calculation of ADC benefits should be modified to account for changes between forecast and actual fuel prices and forecast and actual loads starting in 2026.

Conclusion XV-5: NSPI identifies real-time schedule deviations by the event, not the hour. If actual load and scheduled load are at different OM levels for multiple hours as PHP adjusts to a real time change in schedule, NSPI identifies only one deviation and assigns it to one hour. **(Recommendation XV-4)**

Conclusion XV-6: Identifying deviations on an hourly basis will result in the identification of many more real-time PHP deviations from scheduled load than currently reported. **(Recommendation XV-4)**

Recommendation XV-4: Real-time PHP deviations from schedule should be identified on an hourly basis starting in 2026 and reported in the 2026 ELIADC annual report and any future reports.

Conclusion XV-7: NSPI measures the size of real-time schedule deviations by event, not the hour.
(Recommendation XV-5)

Recommendation XV-5: The size of real-time PHP deviations should be measured by hour, as opposed to event, starting in 2026 and reported in the 2026 ELIADC annual report and any future reports.

Conclusion XV-10: In 2025, positive amounts were included in the calculation of the Cause Code 5 PDN cost penalty resulting in a credit of \$ [REDACTED] for unilaterally deviating from schedule in four hours. In prior audit period calculations positive amounts were set to zero. **(Recommendation XV-6)**

Recommendation XV-6: NSPI should correct the calculation of off-schedule costs associated with Cause Code 5: PDN violations in the 2025 ELIADC Annual Report, to remove positive values, increasing the total cost by \$ [REDACTED] to \$ [REDACTED]

Conclusion XV-8: PHP determines and records off-schedule deviations, not NSPI or NSPSO, in violation of the ELIADC tariff. **(Recommendation XV-7)**

Recommendation XV-7: The NSPSO or successor SO should be required to identify and record PHP real-time deviations from schedule, and the reason for each deviation using verifiable information from PHP.

Conclusion XV-15: No load shifting benefits have been established for real-time active demand control. Real-time load deviations could have resulted in net costs. **(Recommendation XV-8)**

Recommendation XV-8: NSPI should investigate other methods of pricing deviations in real time for PHP such as paying PHP for responding to a request by the SO to change OM level in real time and charging PHP when it deviates from its OM level in real time.

Conclusion XV-16: ELIADC annual reports continue to lack information needed to give FAM customers an objective overview of the pros and cons of the ELIADC tariff and a path for its improvement.
(Recommendation XV-9)

Recommendation XV-9: The Board should include the determination of reporting requirements as part of the proceeding to determine the successor tariff to the ELIADC.

II. Organization, Staffing, and Controls

II.A. Background

This chapter addresses NSPI's organization, staffing, and controls—including risk management—related to fuel and purchased power.

II.B. Findings

II.B.1. Organization

NSPI's fuel and power purchasing and management is the responsibility of NSPI's Energy and Risk Management ("ERM") group. ERM buys solid fuel, natural gas, fuel oils, biomass fuel, and other fuels, additives, and related services for the production of power at NSPI's power plants. ERM also buys and sells power and develops commitment and dispatch schedules for NSPI's generation resources. ERM is the primary unit whose decision-making impacts FAM costs.

In executing its responsibilities, ERM interacts with many other areas of NSPI's organization, many of which have some impact on FAM costs. ERM coordinates with Nova Scotia Power System Operator ("NSPSO," or "System Operator"), on issues such as day-ahead planning and real-time operation of the generation fleet and outages.⁴⁷ NSPI's Portfolio Optimization group is primarily responsible for the fuel and purchased power forecasts that drive NSPI's purchasing decisions. NSPI's Enterprise Asset Management team centrally manages NSPI's generation fleet performance monitoring, maintenance, and management (among other roles), while also providing ERM with the operating characteristics of each of NSPI's generation units. Plant personnel at each of NSPI's generating facilities also play a key role in operating and maintaining NSPI's assets and coordinating with ERM regularly, including during daily day-ahead planning calls. Annual and longer-term load forecasting is the responsibility of NSPI's Accounts and Customer Solutions Group. NSPI's Fuels Accounting and Reporting team provides back-office support to ERM. Throughout the remainder of this report, the roles and performance of these teams are discussed in more detail.

Entering the Audit Period, the organizational structure of ERM remained similar to its structure in the 2022-2023 audit period. Figure II-1 below shows that the Senior Director of ERM reported to the Chief

⁴⁷ In February 2024, IESO Nova Scotia was created to take over several of NSPI's roles. These roles include energy system planning, energy resource procurement, and real-time system operations. For the duration of the Audit Period, these roles stayed within NSPI. Thus, references to the "System Operator" are to the NSPSO, not the IESO.

Operating Officer, while Portfolio Optimization, Compliance, Commercial & Gas, and Solid Fuel Procurement all reported to the Director of ERM.

Figure II-1: NSPI's Fuels-Related 2024 Organizational Chart⁴⁸

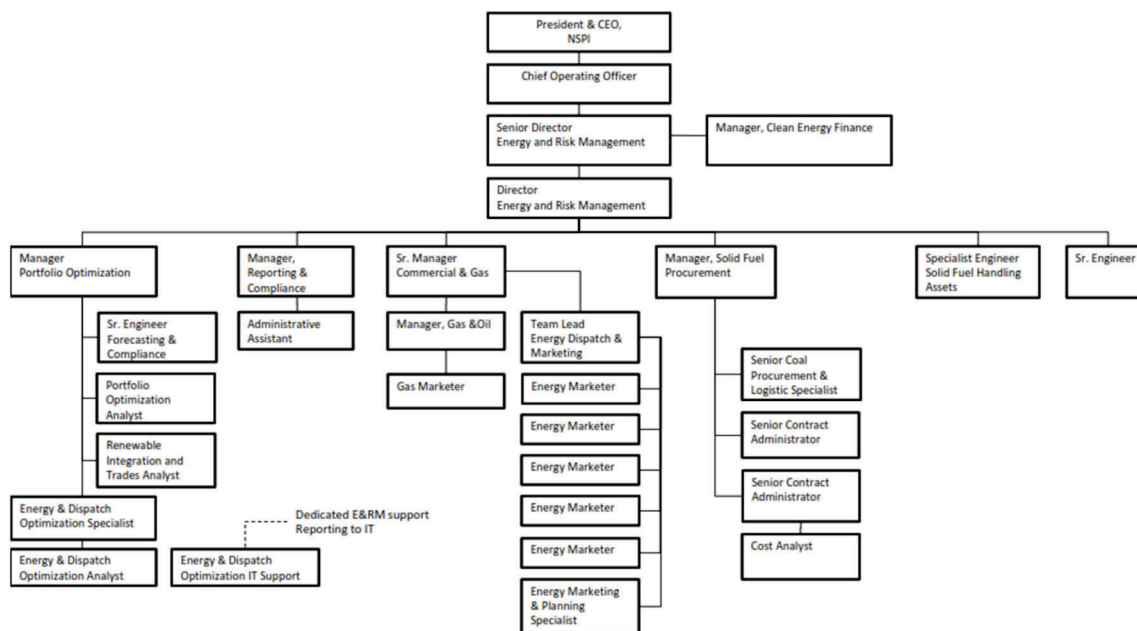


Figure II-2 shows the updated organizational structure that was in place in 2025. The position of Senior Director of ERM was changed to Vice President of Power Production and ERM. The position of Energy & Dispatch Optimization Analyst was transitioned to the Commercial & Gas Division, reporting to the Senior Manager of Commercial & Gas. This position was eventually changed to Markets and Term Power Specialist.

⁴⁸ NSPI 2024 FAM Annual Report, A-1.


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graph TD
    CEO[President & CEO, NSPI] --> COO[Chief Operating Officer]
    COO --> VP[Vice President  
Power Production and Energy & Risk Management]
    VP -.-> MCEF[Manager, Clean Energy Finance]
    VP --> DERM[Director  
Energy and Risk Management]
    DERM --> MPO[Manager  
Portfolio Optimization]
    DERM --> SMC[Senior Manager,  
Compliance & Contracts]
    DERM --> SMC&G[Sr. Manager  
Commercial & Gas]
    DERM --> SML[Sr. Manager,  
Solid Fuel  
Procurement]
    DERM --> SESA[Specialist Engineer  
Solid Fuel Handling  
Assets]
    DERM --> SE[Sr. Engineer]

    MPO --> SEFC[Sr. Engineer  
Forecasting & Compliance]
    MPO --> POA[Portfolio Optimization Analyst]
    MPO --> RITA[Renewable Integration and Trades Analyst]
    MPO --> EDOSS[Energy & Dispatch Optimization Specialist]

    SMC --> MRC[Manager, Reporting & Compliance]
    MRC --> AA[Administrative Assistant]

    SMC&G --> EDOA[Energy & Dispatch Optimization Analyst]
    SMC&G --> MGO[Manager, Gas & Oil]
    MGO --> GM[Gas Marketer]
    SMC&G --> TLEDM[Team Lead  
Energy Dispatch & Marketing]
    TLEDM --> EM1[Energy Marketer]
    TLEDM --> EM2[Energy Marketer]
    TLEDM --> EM3[Energy Marketer]
    TLEDM --> EM4[Energy Marketer]
    TLEDM --> EM5[Energy Marketer]
    TLEDM --> SEMPS[Senior Energy Market and Planning Specialist]

    SML --> SCLP[Senior Coal Procurement & Logistic Specialist]
    SML --> SCA[Senior Contract Administrator]
    SML --> MCA[Manager, Contract Administration]
    MCA --> CA[Contract Administrator]

    EDOSS -.-> EDOIT[Energy & Dispatch Optimization IT Support]
    EDOIT -.-> DERSM[Dedicated E&RM support Reporting to IT]
  
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II.B.2.a. ERM Employees

Our review suggests ERM remained well-staffed with experienced personnel, including in leadership positions. Throughout our audit work, we observed through a series of interviews, discussions by phone, and reviews of individual résumés that ERM personnel were knowledgeable about their specific roles and how their roles fit within the processes and goals of the larger group. We identified no concerning results or personnel changes.

We also reviewed all personnel changes in ERM and Fuels Finance over the Audit Period. We identified no concerning decisions or changes. We noted NSPI has cultivated a team that has shared expertise across functions in some cases. For example, NSPI has four employees working in various planning roles (fuel and purchased power, emissions compliance) that run the PLEXOS model. One notable personnel development was the retirement of a long-tenured ERM employee responsible for natural gas trading and execution of hedge transactions. NSPI hired an additional gas trader and

⁴⁹ NSPI 2025 FAM Annual Report, A-1.

transitioned the execution of financial hedges to other gas traders and, for API-2 index trades hedging solid fuel, to an experienced solid fuel contract specialist.

At ERM overall headcounts increased slightly during the Audit Period, from 28 as of January 1, 2024, to 29 at the end of the Audit Period. This was driven by newly-created positions during the Audit Period, such as the Senior Manager of Regulatory Compliance and Contract Operations.⁵⁰ Descriptions of each role were thorough and clear and the employees filling those roles were well qualified.

We reviewed NSPI's methodology for forecasting attrition and found it to be reasonable. Specifically, NSPI uses five-year averages of both resignations and retirements to develop forecasted attrition rates. These attrition forecasts are for NSPI as a whole and not across individual groups or organizations, such as ERM, where small sample sizes would make such formulaic forecasts less valid. Overall, attrition was reduced relative to the prior audit period, reaching just 6.1% in 2024. This was almost equal to the forecast attrition rate for 2024 (6.2%).

Elsewhere, attrition at NSPI has been low. Figure II-3 below shows the change in headcount at Enterprise Asset Management, the System Operator, and NSPI's generating stations. Enterprise Asset Management headcount remained unchanged and is up 25% at the System Operator. Headcount remained unchanged or increased at all power plants except for Trenton, which experienced a decline of 3.9%.

Figure II-3: Change in Headcount during Audit Period at NSPI Business Units

	As of January 1, 2024	As of December 31, 2025	Change	% Change
Enterprise Asset Management	39	39	0	0.0%
System Operator	20	25	5	25.0%
Lingan	139	140	1	0.7%
Point Aconi	72	77	5	6.9%
Point Tupper	62	62	0	0.0%
Port Hawkesbury Biomass	32	33	1	3.1%
Trenton	103	99	-4	-3.9%
Tufts Cove	99	113	14	14.1%
Combustion Turbines	10	11	1	10.0%
Hydro Stations	79	96	17	21.5%

II.B.2.b. Performance Management

NSPI's performance management process remained consistent with the process put into place in the prior Audit Period. NSPI continued the use of "Performance Review," a third-party software tool to manage and track performance of employees. The overall program and structure remains largely unchanged and similar to the "My Annual Performance Plan" in place in prior audit periods. Under the program, NSPI employees (in consultation with their direct supervisor) outline key accountabilities for

⁵⁰ NSPI 2024 FAM Monthly Report, September.

their position for the year as well as the goals associated with their role for the year. (The job role descriptions and accountabilities (explained above) feed directly into the performance management process.) Employees meet with their supervisor at three regular intervals during the year. First, they meet at the beginning of the year to set accountabilities and goals for the year; next, they meet for a mid-year review to discuss progress on accountabilities and goals and to make adjustments where required; last, they meet at year's end to assess whether all accountabilities and goals were completed, and to what degree the overall performance was achieved.

The performance management program meetings look at both the employee's performance during the previous period and long-term career goals. The employee and supervisor discuss training and additional resources needed to help the employee grow and attain his or her career goals and objectives. Year-end performance ratings are calibrated through a facilitated discussion among managers or leadership teams to create alignment within the organization on the performance ratings and feedback to be given to direct reports. The process helps ensure all employees are evaluated on the same criteria, no matter to whom they report. The calibration process provides leaders with an opportunity to highlight the strengths, accomplishments, and development needs of their team members. In addition, it provides supervisors the chance to gain insight into the perspectives of other supervisors regarding performance of their team members. Following the calibration session, NSPI executive leadership approves all year-end ratings; employees then receive their year-end rating along with feedback from the calibration session. NSPI's performance management process appropriately ties directly to both employees' incentive-based compensation and training and development, as well as to NSPI's succession planning process.

NSPI continues to use a leadership development process as part of its performance management process. NSPI tracks its employees' "Leadership Competencies," which are a combination of observable knowledge, skills, abilities and behaviors which generally result in strong employee performance. There are seven competencies, ranging from "Speaks Up on Safety, Health and the Environment" to "Cultivates Innovation and Embrace[s] Change." The leadership competencies are open for all employees to complete. The Leadership Competency section includes an assessment tool for both management and non-management employees to complete, which identifies one area of strength and one area for growth. These identified strengths and weaknesses are included in the employee's development plan moving forward.

[REDACTED]

[REDACTED] We understand NSPI is engaged in other matters before the Board that address the impact of the cyber event.

II.B.2.c. Training

NSPI continues to require ERM employees to take annual training across a variety of topics, including: (1) the Emera Code of Conduct; (2) the NSPI Power Safety Manual; (3) the NSPI Affiliate Code of Conduct; (4) the NSPI Credit Policy; and (5) NSPI's Risk Management Policy, among others.

Cybersecurity training is also provided quarterly, though again, this is not a cybersecurity audit and it is not in our scope to assess the sufficiency of NSPI's cybersecurity practices or training. New employees are required to take these training sessions upon being hired, and like every other employee, take them again annually. The Senior Manager of Compliance & Contracts coordinates and tracks corporate policy training for ERM employees.

ERM employees also receive more specialized training depending on their role. For example, new employees whose job function provides them with confidential transmission information receive Open Access Transmission Tariff ("OATT") Standards of Conduct training, and all ERM employees are required to take additional FERC compliance training included in the Energy Source Learning Catalogue. Employees also attend training sessions identified through their performance management process as part of their short-term and long-term development plans.

We requested training materials associated with at least one training module used during the Audit Period, but NSPI explained that all trainings were delivered through online portals and thus the materials were not able to be exported for review. In prior audits, we reviewed materials related to several training sessions. The materials themselves were sufficiently detailed, contained very clear definitions and guidelines, and were easily understandable. In the training session on the Affiliate Code of Conduct, for example, we had observed clear and accurate definitions of key terms, appropriate explanations of and guidance on "grey area" issues, and point-of-contact information for NSPI employees who have questions about the Affiliate Code of Conduct. Another example is the training on Credit and Market Risk Concepts and Emera Policy, which defines risk parameters, explains the applicable risk policies in place, and has clear, visual demonstrations of NSPI's systems (e.g., Allegro) as they relate to credit and market risk. Moreover, many of the training topics remain the same as those conducted over prior audit periods. Thus, we had no concerns about the effectiveness of the training materials used during the Audit Period.

II.B.2.d. Incentive-Based Compensation

ERM employee compensation is not a FAM-recoverable expense, but compensation in general for the employees chiefly responsible for FAM-related cost incurrence is relevant. While we did not audit employee compensation, we did review evidence of FAM-related staffing levels and incentive-based compensation for any red flags.

NSPI continues to offer incentive-based compensation to ERM employees and the program remains similar to the prior audit period. NSPI offers two incentive-based compensation programs for NSPI's ERM employees: the Commercial Incentive Program and the Short-Term Incentive Program. Both incentive programs are driven by both individual employee performance and the performance of ERM and NSPI. This remains a reasonable structure that creates incentives for individual employees to perform well, while creating a broader incentive for all employees to strive to meet corporate and departmental goals.

NSPI's Commercial Incentive Program is designed to reward ERM employees based on the success of ERM and the employee's performance. The overall incentive target is expressed as a percentage of the employee's base salary. The Commercial Incentive Program includes six metrics: (1) realizing a lower actual fuel cost than forecasted; (2) achieving hedging targets under the Fuel Hedging Plan and creating value from hedge rebalancing and GHG optimization activities; (3) optimizing Surplus Energy purchases over the Maritime Link; (4) execution of solid fuel procurement strategy and associated FAM savings; (5) optimization of commercial and operational activities to create FAM savings; and (6) fuel cost savings associated with the ELIADC tariff.

NSPI made revisions to the Commercial Incentive program during the Audit Period to reduce both subjectivity in the metrics and after-the-fact adjustments to the calculations of those metrics. NSPI made these revisions in response to one of our recommendations in the prior audit.⁵¹ In making this recommendation, we noted, for example, that NSPI removed from the Commercial Incentive Program "the impact of Maritime Link delays and legislative changes," leading to 2022 results in which NSPI achieved a "100% incentive payout" for the Commercial Incentive Program despite having actual costs exceed forecast by 32.9%.⁵² NSPI was responsive to our recommendation, adding clarity in the calculations of the metrics to account for cost saving opportunities that arise during the period that were unforeseen at the time of incentive development and how to account for actions that become moot during the year. For the 2025 Commercial Incentive Program, NSPI modified their approach to making after-the-fact adjustments. Instead of adjusting the actual FAM costs, corrections to the target metrics were made by removing both the energy and the corresponding actual replacement costs from the fuel and purchased power forecast values. Corrections were restricted to specific items outside of ERM control: (1) impacts of generation projects that are budgeted for but do not achieve commercial operation or expected contribution, (2) impacts of unforeseen legislative changes not captured in the Q1 forecast, and force majeure events, and (3) non-routine maintenance outages impacting energy volumes from Muskrat Falls and LIL beyond the stated forced outage rates assumed in the fuel and purchased power forecast. These revisions were reasonable and responsive to our Recommendation II-1 in the prior audit period. We note that these metrics are likely to continue to be changed by NSPI on an annual basis and should continue to be reviewed for reasonableness and the incentives they create.

The second incentive program is NSPI's Short-Term Incentive plan, which is driven by NSPI-wide performance as well as the individual's performance. Annual performance objectives are established for each individual employee and for NSPI's Power's Corporate Scorecard. Every employee has an individual target incentive based upon his or her level within the organization. At the end of the calendar year, the incentive calculation is based on both individual and company performance. Payments under the Short-Term Incentive plan are a smaller portion of an ERM employee's potential incentive payment than

⁵¹ 2022-2023 Bates White Audit Report, Recommendation II-1.

⁵² 2022-2023 Bates White Audit Report, Section II.B.d.2.

payments under the Commercial Incentive Program—a reasonable approach that recognizes that an employee has more impact over ERM's performance than NSPI as a company.

Both incentive programs are appropriately linked directly to NSPI's performance management program. Specifically, in both incentive programs, ERM employees are assessed a "multiplier" that is used to calculate the size of the employee's bonuses, if any, under these two programs. The multiplier is determined by the employee's year-end performance rating under the performance management program. For example, employees rated as "meeting expectations" receive a multiplier of 1; employees exceeding expectations can earn a multiplier as high as 1.5, and employees failing to meet expectations receive multipliers below 1, and potentially zero. During the Audit Period, approximately 74% of the ratings of ERM employees were "1," a modest decline from the approximately 82% of "1" ratings received by ERM employees in the prior Audit Period.⁵³

We reviewed the results of NSPI's calculated payouts for 2024 and 2025 under the Commercial Incentive Program. We identified no erroneous calculations. NSPI continued to make after-the-fact adjustments to determine results, but those adjustments were limited to factors outside of NSPI's control. Moreover, we observed no evidence of bias in the adjustments. For example, in 2025, in determining performance relative to the "Fuels Budget" metric,⁵⁴ NSPI adjusted both the annual forecast cost and annual actual cost to reflect the "lower [Energy Access Agreement] volumes offered by [Newfoundland and Labrador Hydro]," which increases NSPI's performance on this metric, while also removing the impact of the SO₂ emissions relief received from the province, which decreases NSPI's performance on this metric. In both years, NSPI's Commercial Incentive Program included six worthwhile metrics that, if achieved, help lower cost and risk to FAM customers. These included (1) actual FAM costs compared to FAM budgets, (2) fuels hedging and rate stabilization, (3) acceptance of energy from Newfoundland over the Maritime Link, (4) quantifiable solid fuel savings through transactional or policy outcomes (such as negotiated savings in solid fuel contracts relative to FAM budgets), (5) commercial or operational achievements that lead to quantifiable savings while exceeding renewable energy standard targets, and (6) achieving active demand control savings of at least \$[REDACTED]/MWh or more through administration of the ELIADC. One noteworthy metric outcome involved the solid fuels metric (#4 above) for 2025, in which NSPI achieved the highest possible score driven by NSPI's successful "negotiation" of SO₂ emissions relief⁵⁵ from Nova Scotia Energy and Climate Change.

⁵³ 2022-2023 Bates White Audit Report, p. 27.

⁵⁴ The Fuels Budget metric attempts to incentivize NSPI's FAM-related employees to manage fuel costs in a prudent, cost-effective manner to drive positive economic outcomes for customers. To arrive at the metric result, actual annual fuel costs are compared to BCF budgets. If actual costs equal forecasted costs, the metric is judged to be met and contributes 100% of its weighted value to the incentive payouts for employees. This figure can reach as low as 50% (if actual costs exceed forecasted costs by 50%) and as high as 200% (if actual costs are 50% below forecasted costs).

⁵⁵ This relief is the so-called "Certificate of Variance" discussed later in this report.

II.B.2.e. Succession Planning

NSPI's succession planning process remained in place without material changes during the Audit Period. NSPI continues to employ its "Leadership Potential Assessment" and "Talent Review" processes, which allow NSPI to identify future leaders and provide these leaders with enhanced development opportunities. First, NSPI performs a Leadership Potential Assessment using a formalized, online system similar to the Performance Review program detailed above. The assessment allows NSPI to identify individuals who are ready to take on greater responsibility within the organization.

Based on the results of the Leadership Potential Assessment, NSPI's Talent Review process allows the organization to dedicate greater resources to employees with leadership potential. Through the Talent Review process, these employees will receive specialized development or training opportunities. These opportunities are discussed with the employee and administered through NSPI's Performance Review program.

NSPI conducts ongoing monitoring of its employee demographics and historical data (i.e., average retirement age across NSPI), along with pension plan data to assist in forecasting attrition, including in specialized positions such as plant managers, operators, and engineers. NSPI indicated that it is expecting turnover risk within engineering roles, noting that it anticipates the currently strong labor market demand for engineers to persist over the next five years, which could contribute to attrition. NSPI noted ongoing nationwide infrastructure project investment, including in power generation and energy infrastructure, as a cause for elevated demand for engineering expertise. This risk is most relevant to NSPI's Enterprise Asset Management group.

To mitigate these risks, NSPI combines its monitoring of its personnel and labor market trends with cultivation of talent pipelines. NSPI maintains relationships with both local universities and universities across the Maritimes from which it currently hires several EITs (engineers-in-training) each year, in addition to student placements in rotational programs in other departments. NSPI also indicated confidence in its ability to attract and retain sufficient expert personnel at the thermal generating stations until their retirement. NSPI continues to rely on competitive compensation packages in line with market standards, provision of professional development opportunities and career advancement, and employee engagement to attract and retain sufficient expert personnel.

II.B.3. Controls

II.B.3.a. Fuel Manual

NSPI's 700+ page Fuel Manual remains a useful tool for NSPI to hold its employees accountable to its policies and for the Board to hold NSPI accountable for its decisions related to fuel and power purchasing. Revision 13 of the Fuel Manual, which became effective in August 2021, was in place until October 17, 2024, when Revision 14 of the Fuel Manual became effective. This version of the fuel manual was in effect during the rest of the Audit Period.

The Fuel Manual contains substantial information about the goals and guidelines applicable to NSPI and ERM employees that should serve as guides on a day-to-day basis. It contains appropriate statements of policy—e.g., “[REDACTED]

”⁵⁶—clear references to applicable guidelines—e.g., [REDACTED]

”⁵⁷—and clear statements of goals—e.g., [REDACTED]

s.”⁵⁸ Statements like these codified in the Fuel Manual are important, as they serve to hold NSPI accountable for its actions during the Audit Period and to create a set of best practices that NSPI should follow going forward, even if a particular practice receives little attention by the Board or an auditor for some period of time.

The Fuel Manual also contains the detailed processes and guidelines NSPI must follow in planning and procuring fuel and purchased power across all fuels. This creates accountability, assists employees to do their jobs effectively, and creates a touchstone for NSPI, the Board, stakeholders, and ratepayers to assess NSPI’s performance. Moreover, the Fuel Manual contains the key areas of risk management that dictate how NSPI is to address the inherent risks in transacting for a fuel and purchased power portfolio the size of NSPI’s. We find that the Fuel Manual remains a crucial control in place during the Audit Period.

II.B.3.b. Risk Management

NSPI’s fuel and power purchasing activities inherently expose it to a variety of risks. Prudent utilities manage those risks, such as counterparty, credit, country, market, regulatory, and currency risks,⁵⁹ through well-defined processes, documentation, and organizational structures. NSPI appropriately uses a variety of risk management measures that are industry standard and that should be effective in managing these common utility risks. We detail our findings below.

II.B.3.b.i. Organization

NSPI manages risk both at the company level (i.e., NSPI-specific) and the enterprise level (i.e., Emera-wide). At the enterprise level, Emera’s Board of Directors has the overall responsibility to ensure that the principal risks in the enterprise and operating subsidiaries are identified and that systems and processes have been implemented to manage those risks. Emera’s Board carries out this responsibility by formally delegating authority for risk management to Emera’s Enterprise Risk Management Committee (“ERMC”), which sets the overall framework of the risk management program for Emera and consists of

⁵⁶ [REDACTED]

⁵⁷ [REDACTED]

⁵⁸ [REDACTED]

⁵⁹ Fuel Manual Revision 14, Link 3, section 1.2.

leaders from across Emera's businesses. In the Fuel Manual, it states that the President and CEO of Emera has delegated their responsibilities for the risk management program to the Chief Legal and Compliance Officer of Emera as Chief Risk Officer for Emera.⁶⁰ However, NSPI confirmed with us that the Chief Legal and Compliance Officer of Emera is no longer in place, and thus the CEO of Emera has delegated responsibility for the overall risk management program for Emera to the Executive Vice President Enterprise Risk, who is also the President and CEO of Peoples Gas System, Inc.

Within the enterprise risk umbrella, NSPI follows a top-down approach to risk management whereby the NSPI Board of Directors (or its delegates) discusses and approves policies related to NSPI's risk management program and risk assessment. NSPI's Board of Directors has the overall responsibility to ensure that all principal risks in NSPI's business are identified and that systems and processes have been implemented to identify and manage those risks. The Board of Directors delegate responsibility to NSPI's President and CEO and other NSPI executives and managers.⁶¹ In the Fuel Manual, it states that the NSPI President and CEO has delegated their authority for NSPI's risk management program to the VP Finance of NSPI.⁶² However, during the Audit Period, the CEO delegated that responsibility to the Executive Vice President, Regulatory, Legal and Government Relations until December 15, 2025, at which point it was delegated to (and remains with) the Executive Vice President Finance, Legal and Regulatory. NSPI indicated that it would update the specifics of risk delegation for both NSPI and Emera in the next Fuel Manual update.

NSPI's Credit Risk Oversight Committee ("CROC") is responsible for the overall direction, implementation, structure, coordination, conduct, control, and oversight of NSPI's risk management program. CROC includes senior members of NSPI's management team⁶³ and is chaired by NSPI's Executive Vice President of Finance. CROC updates the ERMC on the nature of NSPI's risk profile and on any significant risk management activities. CROC's numerous responsibilities include ensuring NSPI's risk management program is established, in place, and in compliance with Emera's overall risk management program, as well as monitoring compliance with the Fuel Manual.⁶⁴

NSPI's risk management structure includes a three-office structure that keeps those who are responsible for fuel procurement transactions separate from those required to monitor and manage risk. Specifically, NSPI has a front, middle, and back office. NSPI's front office—which reports to the Director of ERM⁶⁵—is responsible for executing transactions, associated hedges, and assisting the middle

⁶⁰ Fuel Manual Revision 14, Link 3, section 2.1.

⁶¹ Fuel Manual Revision 14, Link 3, section 2.1.

⁶² Fuel Manual Revision 14, Link 3, section 2.1.

⁶³ Current members include: Executive Vice President of Finance (Chair of CROC), Executive Vice President of Regulatory, Legal, & Government Relations, and VP of Customer Experience and Innovation. See Fuel Manual Revision 14, Link 3, Appendix B.

⁶⁴ Fuel Manual Revision 14, Link 3, section 2.4.

⁶⁵ Fuel Manual Revision 14, Link 3, section 2.1.

and back offices to identify, assess, monitor, and report on the risks in NSPI's procurement activities.⁶⁶ NSPI's middle office, which is handled at the enterprise level (by ERM), serves as a control on the front office, policing its activities to ensure data integrity through deal validation, analyzing and monitoring market and credit risks, validating price curves, and reporting risk data to management.⁶⁷ The back office, which reports to NSPI's Controller and is carried out by the Fuels Finance team,⁶⁸ serves as an additional control through maintenance of the balance sheet, (e.g., accounts receivable, accounts payable), settlements, and financial reporting.⁶⁹

Another key player in NSPI's risk management organization is the Fuels Strategy Table ("FST"), which governs NSPI's fuel procurement and hedging activities.⁷⁰ FST's purpose is to govern fuel procurement and hedging by reviewing and approving recommendations related to hedging and procurement of fuel and purchased power, reviewing fuel strategy and planning, ensuring that procurement of fuel and purchased power are in line with the most recent fuel forecast, and reviewing internal audit reports of NSPI's fuel procurement processes and functions, among other things. The FST is chaired by the Director of ERM, who does not vote on matters presented to the FST (prior to March 6, 2025, the FST was chaired by the Senior Director of ERM). Voting members of the FST in 2024 included the President and CEO, the COO, the Executive Vice President of Finance, Legal & Regulatory, and the Vice President of Health, Safety & Environment. In 2025, the roster of FST voting members included the President and CEO, the COO, the Executive Vice President of Finance, Legal & Regulatory, and the Vice President of Power Production and ERM. NSPI's risk management organizational structure is shown in Figure II-4.

⁶⁶ Fuel Manual Revision 14, Link 3, section 2.5.

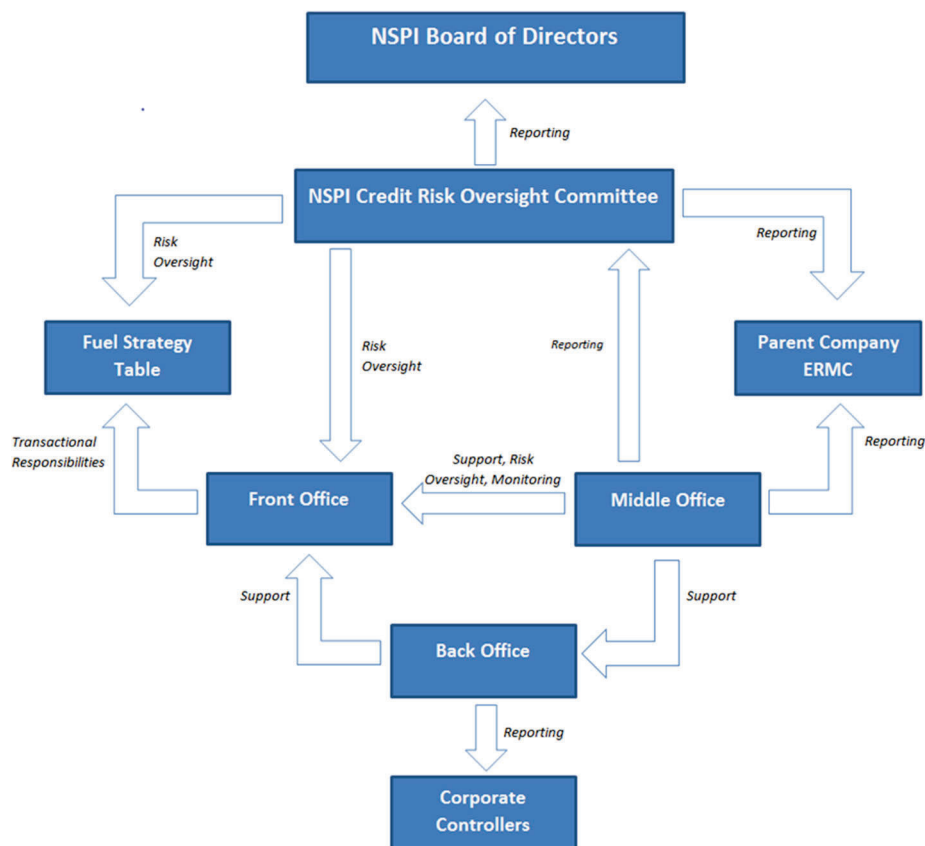
⁶⁷ Fuel Manual Revision 14, Link 4, pages 2 to 3.

⁶⁸ Fuel Manual Revision 14, Link 3, section 2.1.

⁶⁹ Fuel Manual Revision 14, Link 3, section 2.7.

⁷⁰ Fuel Manual Revision 14, Link 3, section 2.8.

Figure II-4: NSPI's Risk Management Organizational Chart⁷¹



II.B.3.b.ii. Risk Management Documents

NSPI's risk management procedures are presented in the Fuel Manual. Provided as "Links" to the Fuel Manual, the key documents that contain NSPI's approach to risk management are (1) the NSPI Fuel Procurement Risk Management Policy & Procedures ("NSPI Risk Manual"), (2) the Emera Incorporated Credit Policy ("Emera Credit Policy"), (3) the Affiliate Code of Conduct, and (4) the NS Power Fuel Hedging Plan. We address each below. In all cases, NSPI's governing risk management documents reasonably define key terms, roles, responsibilities, and approval processes for transacting fuel and purchased power.

The NSPI Risk Manual, which is Link 3 of the Fuel Manual, addresses all risks NSPI faces in transacting for fuel and power, including commodity price market risk, supplier risk, country risk, foreign exchange risk, interest rate risk, credit risk, environmental risk and operational risk.⁷² The NSPI Risk Manual defines CROC's essential role, noting that CROC is responsible for ensuring that "[REDACTED]"

⁷¹ Fuel Manual Revision 14, Link 3, Appendix A.

⁷² Fuel Manual Revision 14, Link 3, section 1.

[REDACTED] as well as other important responsibilities of CROC, such as reporting requirements to the NSPI Board of Directors and to ERMC.⁷³

The Risk Manual also defines the middle office's role, including its day-to-day role as steward of the risk management program and its functional separation from transactional activity at NSPI's front and back office. The Risk Manual also provides specificity regarding actions to be taken by the middle office in the event that there are material violations of the risk management program, and tasks the middle office with the quantification of credit exposures and review authority over credit applications, the approval of credit lines, and certain transactions with new counterparties.⁷⁴ The Risk Manual also explains FST's role in governing NSPI's fuel procurement and hedging activities.⁷⁵

The Risk Manual references other areas of the Fuel Manual as containing some of the terms related to risk management in fuel procurement that must be followed.⁷⁶ For example, NSPI's Solid Fuel Portfolio Process, which is Link 6 of the Fuel Manual, specifies that NSPI is not to commit more than 25% of its solid fuel requirements, at minimum contract levels, to a single mine, that it will limit purchases from any single domestic mine to 40% of NSPI's solid fuel requirements, and that it will strive to diversify the countries of origin of its solid fuel by limiting exposure to any one country of origin to 60%.⁷⁷

NSPI is required to conduct its fuel and freight procurement and hedging activities in accordance with the Emera Incorporated Credit Policy (Link 4 of the Fuel Manual), which governs the credit risk processes, approvals, and authorities applicable to commodity transactions and hedging activities for NSPI and its affiliates. The Emera Credit Policy's purpose is to focus on credit risk, which it defines as

"[REDACTED]"⁷⁸ Importantly, the Emera Credit Policy further explains and offers more examples regarding credit risk, which is an important feature of good risk management policies; specifically, the Emera Credit Policy explains that financial risk includes "[REDACTED]"

[REDACTED]
[REDACTED]
[REDACTED], " as well as "[REDACTED]"

[REDACTED]
[REDACTED]⁷⁹ It is reasonable and expected that NSPI, as part of a broader organization of Emera affiliates, is subject to an Emera-wide credit policy, as it

⁷³ Fuel Manual Revision 14, Link 3, section 2.4.

⁷⁴ Fuel Manual Revision 14, Link 3, section 2.5.

⁷⁵ Fuel Manual Revision 14, Link 3, section 2.8.

⁷⁶ Fuel Manual Revision 14, Link 3, section 1.1.

⁷⁷ NSPI Solid Fuel Portfolio Process, Link 6 of Fuel Manual Revision 14, page 4.

⁷⁸ [REDACTED]

⁷⁹ [REDACTED]

remains good practice for entities such as Emera to monitor and set limits and guidelines for transacting and the inherent credit risk that doing so accrues.

The Emera Credit Policy clearly identifies and defines the key roles for managing risk across the Emera-wide portfolio of affiliates, including the role of the Board of Directors, the ERM, and the ERM, as well as the roles of affiliates' front and back offices, including NSPI's.⁸⁰ The Emera Credit Policy tasks the NSPI front office with "[REDACTED]".⁸¹ We observed several instances of the front office seeking CROC approval of particular transactions during the Audit Period.

The Emera Credit Policy also includes clear credit limits for application to all counterparties with which Emera or its subsidiaries transact. For example, the Emera Credit Policy specifies a credit limit of \$15 million for entities with credit ratings of "A" by Standard & Poor's; moreover, absent approval from senior management, NSPI and its affiliates are prohibited from extending credit to any entities that are not investment grade.⁸² Some exceptions to these credit limits exist, such as those for procurement of solid fuel, which the Emera Credit Policy appropriately recognizes as requiring a different approach.⁸³ During the Audit Period, the Emera Credit Policy was updated once on November 26, 2025, though we observed no material changes in the updated policy.

A third important risk management document is the Affiliate Code of Conduct, which is included as Link 5 to the Fuel Manual. The purpose of the Code of Conduct is to govern NSPI's business dealings with its affiliates and applies to all employees.⁸⁴ The Code of Conduct makes it clear that affiliate transactions are only allowed "when doing so has been demonstrated through sound, documented analysis to be the best available option for NS Power's customers at the time" and that NSPI will not "subsidize its Affiliates by charging too little or paying too much for Affiliate Transactions."⁸⁵ The Code of Conduct applies to all NSPI affiliates other than NSPEMI and NSP Maritime Link.⁸⁶ NSPI can also apply for additional exemptions from the Code of Conduct by making an application with the Board. The Code of Conduct contains fair dealing and clear pricing requirements for any affiliate transactions⁸⁷ and prohibits certain affiliate transactions, such as assumption of affiliate debt or the pledging of other financial support to NSPI's affiliates.⁸⁸

⁸⁰ Fuel Manual Revision 14, Link 4, pages 1-3.

⁸¹ [REDACTED]

⁸² Fuel Manual Revision 14, Link 4, page 4.

⁸³ Fuel Manual Revision 14, Link 4, page 4.

⁸⁴ Fuel Manual Revision 14, Link 5, page 1.

⁸⁵ [REDACTED]

⁸⁶ Fuel Manual Revision 14, Link 5, section 3.2.

⁸⁷ Fuel Manual Revision 14, Link 5, section 6.

⁸⁸ Fuel Manual Revision 14, Link 5, section 5.

The fourth key risk document is NSPI's Fuel Hedging Plan, which is included as Link 12 to the Fuel Manual. We address NSPI's hedging activities in detail in a later chapter; here, we note that the Fuel Hedging Plan contains the guidelines for NSPI to follow in hedging its exposure to variable fuel and power costs during the 2022-2024 Fuel Stability Period.⁸⁹ NSPI's Fuel Hedging Plan remains similar to the hedging plan in place during the 2017-2019 Rate Stability Period and 2020-2022 Fuel Stability Period.

II.B.3.b.iii. Risk Management Systems

NSPI continues to use Allegro's Energy Trading and Risk Management ("ETRM") software as its energy trading and risk management system. ETRM is used for deal capture, credit and market risk monitoring, and settlement. The Allegro database captures NSPI's physical and financial gas, power, coal, and oil positions centrally, as well as current forward market pricing and historical spot and forward market data.⁹⁰ The middle office retains the responsibility for maintaining the Allegro database and updating changes to the database content and is also tasked with being the "owner" of Allegro and of the integrity of the data.⁹¹ Allegro is sometimes referred to as "Allegro Horizon" or "Horizon," but for continuity's sake, we continue to refer to the product simply as Allegro.

NSPI also uses Aligné Fuels to manage heavy fuel oil ("HFO"), light fuel oil ("LFO"), diesel, and solid fuel information.⁹² Aligné Fuels is an off-the-shelf commercial software system designed for the power generation industry to manage fuel information from procurement through to consumption and account for the expense. Generation and fuel consumption data are collected from each plant and exported to the Aligné Fuels database. Information on fuel suppliers, contracts, and fuel types is administered within Aligné Fuels. Like Allegro, Aligné interacts with NSPI's other systems, including the Oracle billing system; under normal circumstances, fuel data from Aligné is uploaded monthly to Oracle Financial Systems for financial reporting purposes.⁹³

[REDACTED]

[REDACTED]

[REDACTED] Throughout the remainder of this report, the impact of the cyber event on FAM-related operations, including the use of Allegro and Aligné Fuels, are discussed in more detail.

II.B.3.b.iv. Audit Period Results

While we discuss in our FAM Accounting chapter more detail about NSPI's controls and their performance during the Audit Period, we generally observed that NSPI takes the role of the FST seriously and that FST functioned as required and designed in reviewing and approving numerous transactions

⁸⁹ Fuel Manual Revision 14, Link 12, page 3.

⁹⁰ Fuel Manual Revision 14, Link 3, section 5.1.

⁹¹ Fuel Manual Revision 14, Link 3, section 5.1.

⁹² Fuel Manual Revision 14, Link 3, section 5.1.

⁹³ Fuel Manual Revision 14, Link 3, section 5.1.

In this Audit Period, NSPI reported no instances of violations of its risk management policies. In our review of Audit Period data, we noted Records of Approval in which ERM, in seeking approval for a given transaction, sought and received approval from CROC as it related to counterparty risk or creditworthiness issues. This is good evidence that NSPI takes risk management seriously in its FAM-related contracting.

Country	Share of GDP
United States	1.0%
Germany	0.9%
France	0.8%
Italy	0.7%
Spain	0.6%
Japan	0.5%

NSPI's Fuel Manual contains provisions associated with NSPI's internal auditing process:



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NSPI's internal audit team is an Emera entity that is shared across the Emera companies, including NSPI.⁹⁵ During the Audit Period, NSPI conducted three internal audits (dated February 2024, March 2025, and December 2025, respectively), which we reviewed.

The first internal audit, dated February 2024, addressed NSPI's FAM reporting process, and NSPI's internal auditing team found NSPI's process to be "Acceptable," the highest possible score assessment (others include "Requires Improvement," "Requires Substantial Improvement," and "Not Acceptable"). The internal audit report was clear and concise in its purpose, findings, recommendations, and reasoning for those findings. The internal audit recommended (1) the establishment of formal procedures to periodically review user access to the Shared Drive and SharePoint Folders used by the Fuels Team for FAM Reporting, (2) that evidence of review be maintained, (3) performing a full review of current SharePoint site access and removing employee access if not required for their job, and (4) that management updates UARB report approval processes to include documenting and retaining evidence of the review. In response to the findings of this audit, NSPI developed a semi-annual review process of the list of employees with permission to access the Sharepoint site and the fuels finance network drive. In addition, NSPI has created a process to document review and/or approval of the monthly, quarterly, and annual FAM reports filed with the Board.

The second internal audit (completed in March 2025) addressed NSPI's fuel forecasting and supply planning process, and NSPI's internal auditing team found NSPI's process to be "Acceptable." The internal audit report was clear and concise in its purpose, findings, recommendations, and reasoning for those findings. The internal audit recommended that management conduct refresher training on input validation to ensure team members understand what to review and verify. We followed up with NSPI to determine if this recommendation was adopted and has been implemented. In response to the recommendations of the audit, NSPI developed an action plan, which included a cross-check of the parameters in PLEXOS by a second team member, a team review of the PLEXOS outputs against assumptions (such as

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95 2022-2023 Bates White Audit Report, p. 35.

generation outages), and a final review (by a senior team member) of preliminary and final forecasts against historical statistics and current inputs.

Dated December 2025, the third internal audit addressed NSPI's hedging program development and effectiveness process, and NSPI's internal auditing team found NSPI's process to be "Acceptable." The internal audit made no recommendations. NSPI noted that the audit scope was limited to assessing processes to manage and monitor hedging activities by management and to test effectiveness of the hedging portfolio, and that the underlying analysis could not be opined upon because detailed support was unavailable as a result of the cyber event. This was a reasonable conclusion, given the lack of data access. However, in our view, it will be important for the internal audit team to complete this audit to the extent it can when data access is restored. We include a recommendation that this audit be completed as soon as practicable and to the extent possible.

II.B.4. Bates White's 2022-2023 Recommendations

We had one recommendation regarding Organization, Staffing, and Controls in our prior Audit Report. This was:

Recommendation II-1: NSPI should review its Commercial Incentive Program metrics to reduce, if possible, after-the-fact adjustments and subjectivity.

NSPI accepted this recommendation, noting that "NS Power will devise an approach for the 2025 Program...that strives to minimize the need for after-the-fact adjustments."⁹⁶ We noted in our February 21, 2025 Rebuttal Evidence that we considered NSPI's response to be "positive and satisfactory."⁹⁷ As we explain above in section II.B.2.d, NSPI took steps to be responsive to our recommendation and reduce after-the-fact adjustments and subjectivity. We consider NSPI to have fully addressed this recommendation.

II.C. Conclusions

Conclusion II-1: NSPI's organizational structure remains reasonable and well defined, with the roles across the organization adequately specified, including responsibilities, which can help create an environment of accountability.

Conclusion II-2: ERM is well-staffed with experienced personnel. Other organizations with which we frequently interacted during our audit, including those in Fuels Finance, Enterprise Asset Management,

⁹⁶ NSPI, Exhibit N-3(C), M11533, September 13, 2024, page 14, lines 10-11.

⁹⁷ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 22.

Power Production, and the Energy Control Center – were also staffed with experienced personnel. New hires were well-qualified.

Conclusion II-3: FAM-related personnel attrition rates at NSPI and headcounts were reasonably steady during the Audit Period. NSPI's methodology for forecasting attrition rates is reasonable.

Conclusion II-4: NSPI's performance management program continues to meet industry standards and is well integrated with NSPI's compensation programs, training efforts, and succession planning.

Conclusion II-5: NSPI's training programs are adequate and have a proper focus on both regular, annual training in crucial risk management and code of conduct issues, as well as employee-specific training to further develop NSPI's human capital.

Conclusion II-6: NSPI's performance-based incentive programs provide incentives for NSPI employees to perform in their positions in ways that help minimize costs to FAM customers. Both the Commercial Incentive and Short-Term Incentive Programs balance both the individual's performance with the performance of the larger entity—ERM in the former case, and NSPI in the latter. In response to a prior audit recommendation, NSPI made revisions to the Commercial Incentive program during the Audit Period to reduce both subjectivity in the metrics and after-the-fact adjustments to the calculations of those metrics.

Conclusion II-7: NSPI's succession planning program for ERM employees remained a useful process that helped – and should continue to help – NSPI address short-term disruptions in its labor force, help ERM employees to define their desired roles in the future, assist employees in developing needed skills and experience to enter those roles, and assist NSPI in managing its long-term human resources.

Conclusion II-8: NSPI's Fuel Manual is a useful tool that helps hold NSPI's employees accountable to its policies and for the Board to hold NSPI accountable for its decisions related to fuel and power purchasing. The Fuel Manual contains a substantial amount of information about the goals and guidelines applicable to NSPI and ERM employees that should serve as the guiding document on a day-to-day basis. Fuel Manual Revision 14 became effective on October 17, 2024.

Conclusion II-9: NSPI's risk management processes, procedures, organization, and documentation are reasonable and should encourage effective risk management. As part of a broader corporate entity with multiple affiliates (Emera), NSPI has risk management that is appropriately driven in part by Emera-wide policy, particularly related to credit risk. NSPI's documentation of risk management assigns sufficient levels of accountability for key personnel at NSPI and provides clear guidelines regarding definitions of risk, transaction and contract approval thresholds, and reporting procedures.

Conclusion II-10: The NSPI Risk Manual's current language regarding risk management organization is partially outdated, as it indicates delegation of risk responsibilities within Emera and NSPI to personnel

that no longer have that responsibility. NSPI indicated that it would update the specifics of risk delegation for both NSPI and Emera in the next Fuel Manual update. **(Recommendation II-1)**

Conclusion II-11: The March 2025 cyber event had a material impact on NSPI's internal controls. Loss of access to Aligner Fuels and Allegro required manual workarounds to maintain recordkeeping. While these systems themselves required some degree of manual data entry, the loss of those systems meant the loss of one additional source of potential quality control and assurance.

Conclusion II-12: In this Audit Period, NSPI reported no instances of violations of its risk management policies. In our review of Audit Period data, we noted Records of Approval in which ERM, in seeking approval for a given transaction, sought and received approval from CROC as it related to counterparty risk or creditworthiness issues. This is good evidence that NSPI takes risk management seriously in its FAM-related contracting.

Conclusion II-13: NSPI conducted three internal audits during the Audit Period. Reports were clear and concise in their purpose, findings, recommendations, and reasoning for those findings.

Conclusion II-14: NSPI's December 2025 internal audit addressing the hedging process was found to be "Acceptable" and contained no recommendations. However, NSPI noted that the audit scope was limited to assessing processes to manage and monitor hedging activities by management and to test effectiveness of the hedging portfolio, and that the underlying analysis could not be opined upon because detailed support was unavailable as a result of the cyber event. This was a reasonable conclusion, given the lack of data access. However, in our view, it will be important for the internal audit team to complete this audit to the extent it can when data access is restored. **(Recommendation II-2)**

II.D. Recommendations

Recommendation II-1: NSPI should ensure its next Fuel Manual update revises the NSPI Risk Manual, as necessary, to make accurate references to risk management authority delegations at both NSPI and Emera.

Recommendation II-2: NSPI should complete its December 2025 internal audit of NSPI's hedging program as soon as practicable and to the extent possible.

III. Forecasting and Fuel Supply Planning

III.A. Background

The purpose of the Fuel Adjustment Mechanism—to ensure that power rates reflect the actual cost of the fuel used to produce the power and not simply a forecast of fuel need—highlights the importance of accurately forecasting the energy and peak capacity requirements of NSPI's in-province customers and the least cost supply plan to satisfy them. This chapter addresses NSPI's forecasting and planning processes and practices during the 2024-2025 Audit Period.

III.B. Findings

NSPI's overall approach to FAM cost forecasting during the Audit Period was similar to the forecasting processes in place in recent years. The long-term load forecast remained the basis for fuel supply planning, investment planning, and overall operating activities of NSPI required to serve customer load over a 10-year time horizon. NSPI's load forecast is the aggregate of separate forecasts for each customer class. NSPI uses Statistically Adjusted End-Use ("SAE") models to forecast the load for the residential and commercial rate classes; an econometric model for the industrial class load forecast; and customer-specific forecasts for some individual large customers. The forecasting models used by NSPI incorporate analyses of sales history and take into consideration weather, end-use saturations and efficiencies, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other means to supply customers' loads. The customer class forecasts are ultimately aggregated to develop an energy forecast for the province, also referred to as a Net System Requirement ("NSR"), which represents in-province sales plus associated losses, net of exports and station service. NSPI also forecasts peak hourly demand, defined as the highest single hourly average demand experienced in a year, based on the forecast energy requirements and expected load shapes. The peak hourly demand includes both firm and interruptible loads. An annual forecast broken out by month is prepared each year at the end of the second quarter. The results are documented in an annual Load Forecast Report, which is filed with the NSEB each year. There were no significant changes to the forecasting methodology and no organizational changes impacting the load forecasting process during the Audit Period.

The quantities of the various fuels required to supply the forecast load at the lowest possible cost are estimated using a model that simulates the operation of each generating unit and their dispatch in economic merit order, subject to transmission security and environmental constraints. NSPI again used PLEXOS for this purpose. PLEXOS is a commitment-based, security constrained, chronological dispatch optimization software. PLEXOS has the capability to model all system emissions subject to not-to-exceed

limits and shadow prices and can optimize dispatch to any or all of the modeled air emissions, including sulphur dioxide (“SO₂”), greenhouse gases (“GHG”), mercury, or nitrogen oxide (“NO_x”).

To forecast the amount of each fuel required to operate the generating units over a given forecast period, the model must consider (1) the technical and economic characteristics of NSPI’s generating units; (2) a price forecast for each of the fuels used in generation; (3) the impact of GHG limitations; (4) various other assumptions regarding NSPI’s units operation (such as alternative fuel blends and associated emissions); (5) purchased power costs; and (6) the topology and capacity of the transmission system.

To account for future changes in the Nova Scotia power grid over the forecast period, the model requires a schedule of generating unit additions and retirements, as well as a transmission expansion plan. Based on this information, PLEXOS’ optimization algorithms find the lowest cost dispatch that complies with mandated emissions limits, producing an estimate of the energy generated by and the fuel requirements of each generating unit, and the total quantities of each fuel required to operate NSPI’s generating units. The annual fuel budget is calculated based on the quantities of each fuel and its respective price. NSPI forecasts its fuel requirements and budget quarterly, thus requiring a new PLEXOS run with the same frequency. NSPI may also conduct interim forecasts, as needed, due to exogenous events that may have significant impacts on fuel and purchased power forecasts. An example from the Audit Period is receipt of a Certificate of Variance for sulfur emissions compliance, which had a material impact on NSPI’s expected fuel and purchased power mix.

NSPI also accounts for environmental constraints and requirements in its forecasts. As explained below, NSPI’s forecasts accounted for limitations on GHG emissions, as well as other emissions limits (e.g., sulfur). Quarterly PLEXOS forecasts are used to develop emissions compliance adders which are used as a starting point in the development of a seven-day model run using PortOps. The cyber event impacted availability of certain systems during the Audit Period, which we explain below.

III.B.1. Overall Adequacy of Forecasting Models and Data

III.B.1.a. Energy Sales Forecasting

NSPI forecasts long-term system load (energy) and system peak demand using separate models for its residential, commercial, and industrial sector customers. The forecasting methodology and organization involved in the load forecasting process remains similar to that used in the previous audit period. NSPI’s load forecast is filed annually with the Board.

The residential sales forecast is the product of the residential average use forecast and a forecast of customer count. Historical load data used in the model consists of 10 years of monthly billed sales data. Economic data (GDP, employment, housing starts) is based on the Conference Board of Canada 20-year Outlook, which is updated annually. Appliance energy use information (energy intensities and

saturations) comes from Natural Resources Canada (“NRCan”) and the US Energy Information Administration (“EIA”) for New England, adjusted for Nova Scotia (also updated annually). Weather data is based on 10 years of Environment Canada hourly temperature records to produce normal monthly Heating Degree Day and Cooling Degree Day variables, with an 18° C base.

The 2025 Load Forecast Report forecasts an average annual *decrease* in load of 0.2 percent between 2025 and 2035. NSPI identified several reasons for this forecast. First, NSPI updated its forecast of Renewable to Retail (“RTR”) load, which serves to reduce the load that NSPI must serve (and therefore reduce its forecasted load). In NSPI’s 2024 load forecast, NSPI forecasted RTR load to begin in 2025 (61 GWh) and increase in 2026 (246 GWh); in the 2025 load forecast, NSPI recognized that the RTR program’s impact would not materialize in 2025 and would have a smaller impact in 2026 (144 GWh). (In reviewing this issue with NSPI, NSPI indicated that it now did not expect any RTR impact in 2026.) Because the RTR impact is now delayed and reduced, NSPI’s forecasted load in 2025 and 2026 are higher than in the prior forecast. Moreover, NSPI is forecasting higher RTR growth in the remainder of the forecast horizon, reducing NSPI’s forecasted load.

Second, NSPI reduced the estimated impact of new electric vehicles. For its 2025 load forecast, NSPI forecasted 510 GWh of new electric vehicle load from 2025-2034 (inclusive), down 6.9% from its 2024 load forecast estimate of 548 GWh over that period. Third, NSPI is also forecasting load reduction due to increased behind-the-meter solar; NSPI forecasted annual load reduction of 743 GWh by 2034 associated with new installed capacity from 2025-2034, an increase of about 21% from the 2024 load forecast of annual load reduction of 590 GWh by 2034 associated with new installed capacity over that period. Fourth, continued growth of demand side management (“DSM”) and energy efficiency are set to further limit load growth. These load-reducing factors are forecasted to outweigh forecasted customer growth and continued electrification of the heating sector.

NSPI’s commercial SAE models express monthly sales as a function of heating, cooling, and other loads. The Small General Service forecast is based on a monthly SAE average use model and a separate customer count forecast. The General Service rate class model is estimated on a total monthly sales basis, where total monthly billed sales are a function of total monthly heating requirements, cooling requirements, and other uses. In the 2025 load forecast, Small General Service load shows an increase of 1.5 percent per year over the 10-year forecast period compared to 1.8 percent increase per year in the 2024 load forecast. NSPI attributes the net increase to commercial electrification offset by a combination of DSM and decreased intensity forecasts for the ventilation, lighting and miscellaneous end uses. General Service sales were expected to decrease by 0.8 percent annually during the 10-year forecast period, compared to a predicted decline of 0.1 percent in the 2024 forecast. NSPI attributed the larger decrease to lower electric vehicle load, the commercial energy impact of hybrid heating, greater RTR program impact, and higher distributed solar offsets.

Large General Service sales are forecast using a combination of historical information and customer surveys to determine electricity requirements over the next three years. In the absence of information on

individual customer load changes via survey or public information, load levels are forecast as flat before the impact of DSM. In 2025, fourteen of nineteen Large General Service customers replied to the annual survey, with five indicating no change, nine indicating an increase, and none indicating a decrease. The forecast expects a *decrease* of 12 GWh by 2035, which NSPI attributes to DSM outweighing projected growth.

The SAE models NSPI used in its forecasting of residential and commercial load remain well suited to accommodate the growing penetration of energy-efficient and demand-response technologies and improvements of these technologies over time. The end-use variables in the residential and commercial SAE models are based on end-use intensity projections that capture expected end-use intensity trends. Over the 10-year forecast horizon, actual end-use intensities can vary from projected trends due to multiple factors, including changes in the commercial availability and price of new technologies, tax and cash incentives designed to accelerate the adoption of new technologies, etc. Examples of these changes, relatively underestimated in forecasting until recent forecasts, include reductions in the price and increased availability of LED lighting and smart thermostats. Changing trends in preference for multi-unit over single unit housing in new household formation could also significantly affect energy consumption for new customers over the forecast horizon. NSPI's 2025 forecast, for example, forecasts that approximately 63% of new housing starts by 2035 will be multi-unit.

The Small Industrial and Medium Industrial class load forecasting models used in the Audit Period were econometric-based models, with provincial GDP as the primary economic variable for Small Industrial and manufacturing employment for the Medium Industrial class. The models were developed using monthly sales information to align their timeframes with those of the residential and commercial forecast models, and thus be able to produce a joint end-use based peak demand forecast. Sales for the Small Industrial rate class have been flat for the last 10 years and are expected to remain essentially flat, with growth of 0.1 percent annually over the forecast period as a result of underlying economic growth offset by migration to the RTR program (10 GWh). Sales for the Medium Industrial class, essentially flat since 2014, experienced an increase in the 2019 to 2022 period due to several new facilities ramping up production, with minimal impact from the pandemic restrictions. However, sales are expected to decline in 2026 and 2027 as load migrates to the Renewable to Retail market (84 GWh), resulting in an average annual decline of 1.4 percent through 2035.

The load forecasting models for customers served under the Large Industrial, Large Industrial Interruptible, Generation Replacement and Load Following, One-Part Real-Time Pricing, Shore Power and Extra Large Industrial Active Demand Control ("ELIADC") tariffs are based on historical sales information combined with customer surveys used to determine energy requirements for the next three-year period based on planned production levels or equipment changes. These forecasting approaches can provide a reasonably accurate basis for forecasting load, as long as intelligence gathering on future changes in load requirements of large customers are diligently conducted. Customers are surveyed annually, and in the absence of a response, are assumed flat. Of its 30 customers under these tariffs, half

indicated no expected change to their consumption in the 2025 survey, while five indicated an increase and one indicated a decrease (nine customers did not respond). Based on survey results, NSPI expects limited growth over the forecast horizon, as growth (especially by its largest customer) is mitigated by load migration to the RTR market of 34 GWh by 2027.

NSPI's long-term load forecast also considers demand from six municipal utilities that purchase wholesale power from NSPI and distribute it within their service territories. Four of those municipalities now purchase 100 percent of their energy requirement from suppliers other than NSPI, resulting in a reduction in NSPI's municipal load of about 150 GWh from historic levels. Beginning in 2025, NSPI now forecasts 100% of municipal power from these four municipalities to be served by third parties, though NSPI must continue to provide backup capacity, for such utilities and must plan for serving these customers in the long-term. As such, the full amount of the municipal electric utilities' peak demand is included in NSPI's load forecast.

DSM and conservation plans are incorporated into the forecast by reducing the load forecast by Efficiency One's annual projected savings for each sector (residential, commercial, and industrial). To prevent double counting DSM activities (in both the forecast regression models and the projected end-use data), NSPI uses cumulative historical DSM savings (as reported by Efficiency One) in the regression model as a load modifying variable and allows the model to determine what level of DSM is already included in other variables. This is the same approach NSPI has used in recent historical load forecasts.

III.B.1.b. Net System Requirement Forecast

The NSR is the energy required to supply the sum of the residential, commercial, and industrial electricity sales, plus the associated system losses with Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included in NSR. NSPI forecasts NSR to decline at 0.2% per year through 2035.

In 2024, NSPI's actual NSR (11,326 GWh) was 1.43% below forecast (11,490 GWh).⁹⁸ This was driven in part by the weather, with the system experiencing 3,561 heating degree days in 2024, well below the 10-year average of 3,715. In 2025, actual NSR was 0.60% below forecast (11,469 GWh actual vs. 11,539 GWh forecasted).⁹⁹

III.B.1.c. System Losses and Unbilled Sales

Physical losses in NSPI's transmission and distribution system plus any energy generated and sold but not yet billed averaged 6.6 percent of NSR over the past five years and are forecast to remain in the 6.0 to 7.0 percent range over the 10-year forecast period.

⁹⁸ Q4 2024 FAM Report, tab Q(6) NC.

⁹⁹ Q4 2025 FAM Report, tab Q(6) NC.

III.B.1.d. Peak Demand Forecasting

The long-term system peak forecast for the accrued classes is derived through a linear regression model that relates monthly peak demand (excluding large customer contribution) to heating, cooling, and base load requirements derived from the class sales forecast models for “Residential,” “Small General Service,” and “General Service” customers. The monthly heating and cooling requirements from the class sales models are normalized for the number of days and hours for each month and interacted with peak-day Heating Degree Day and Cooling Degree Day measurements. The peak model’s base load variable captures the impact of loads that are not weather sensitive on peak, including residential and commercial, other (non-cooling and heating) lumped end-use components, and industrial and unmetered sales. The contribution to peak of the various growth programs (heat pumps, hot water heaters) are calculated based on End Use Intensities (including their associated losses). The contribution of the large customer and interruptible customer classes (commercial and industrial) are calculated from historical coincident load factors for each rate class. All these, along with the impact of DSM, are then added to the modeled peak to get the total system peak.

Demand response savings are based on the demand reduction amounts were the outcome of a third-party study. The demand response modeled includes programs such as Direct Load Control and Time Variable Pricing, and assume an effective load carrying capability (“ELCC”) of 48 percent.

The 2025 Peak Demand forecast estimates steady peak load growth averaging 1.2 percent per year through 2035.

III.B.1.d.i. Accuracy of NSPI’s Load and Peak Demand Forecasts

The accuracy of the forecast of the Total System Requirement for the Audit Period years (2024 and 2025) was in line with results from the prior audit period (2022-2023), as shown in Figure III-1. The accuracy of the forecast is reasonable and is comparable to the forecast accuracy of other utilities.

Figure III-1: Comparison of Total System Requirement Forecast vs. Actual (MWh, 2022 through 2025)¹⁰⁰

Year	Actual	Forecast	Variance
2022	11,133,919	11,279,702	-1.29%
2023	11,138,520	11,180,622	-0.38%
2024	11,326,320	11,240,054	0.77%
2025	11,473,610	11,541,221	-0.59%

NSPI’s 2024 actual peak load (2,088 MW) was 6.2 percent lower than forecast (2,225 MW). Similarly, in 2025, NSPI’s actual peak load (2,267 MW) was 6.1 percent lower than forecast (2,415 MW). These moderate over-forecasted peaks resume a trend observed since 2020 in which NSPI’s forecasted annual peak load exceeded actual peak load. That changed on February 4, 2023 during a cold weather

¹⁰⁰ Q4 2024 FAM Report, 2(3); Q4 2025 FAM Report, 2(3).

event that was the subject of an NSPI report to the Board.¹⁰¹ The peak load that day—2,455 MW—was the highest load ever experienced on the NSPI system, exceeding the prior record by 217 MW (or 9.7 percent).¹⁰² The actual and forecast peak data is shown in Figure III-2.

Figure III-2: NSPI's Estimated Firm System Peak and Actual Peak Load (MW, 2020 through 2025)¹⁰³

Year	Actual	Forecast	Variance
2020	2,050	2,234	-8.24%
2021	1,968	2,243	-12.26%
2022	2,216	2,248	-1.42%
2023	2,455	2,155	13.92%
2024	2,088	2,225	-6.16%
2025	2,267	2,415	-6.13%

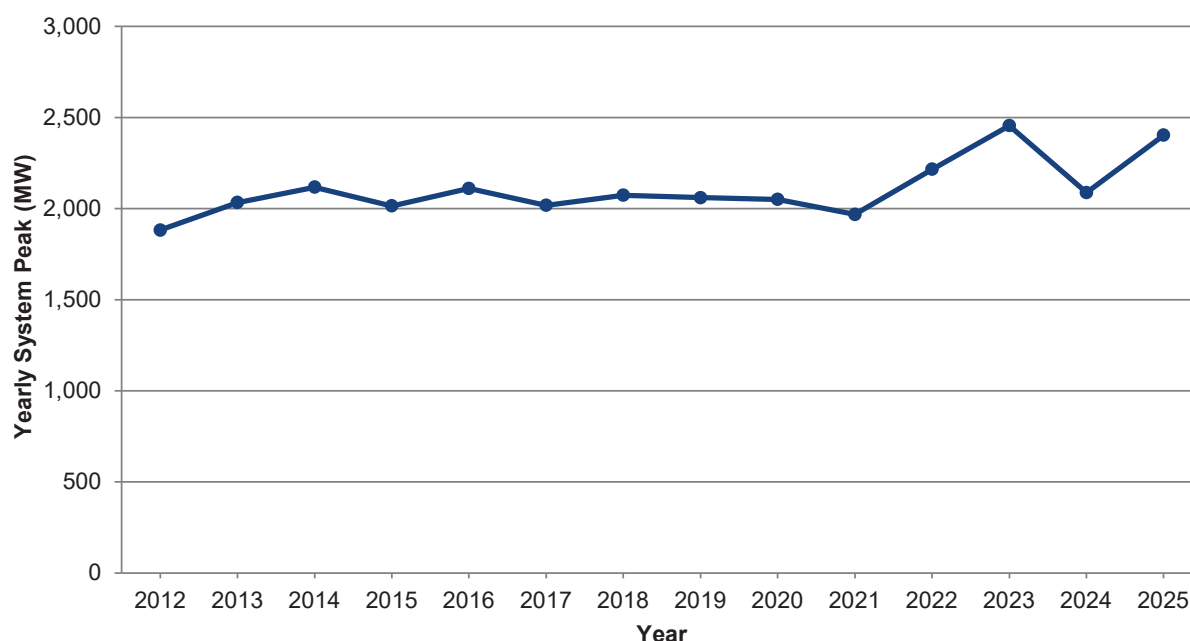
The data in the figure above shows significant differences in most years between forecast and actual peak, with most years showing overestimated peak demand (2020-2022, 2024-2025) and one year showing substantially underestimated peak demand (2023). As we have noted in prior audit reports, this data should not necessarily be a cause for alarm but suggest caution in making long-term decisions based on a single year peak demand forecast value. Figure III-3 below shows yearly peak demand since 2012.

¹⁰¹ NSPI, "Preliminary Outage Report for February 3-5, 2023 Cold Weather Event," M10987, February 21, 2023.

¹⁰² NSPI, "Preliminary Outage Report for February 3-5, 2023 Cold Weather Event," M10987, February 21, 2023, page 4.

¹⁰³ 2022-2023 Bates White Audit Report, page 44.

Figure III-3: NSPI Peak System Demand Trend (2012-2025)¹⁰⁴



Given the forecasted increase in peak demand, we inquired with NSPI regarding the status of its various programs used to mitigate peak demand. NSPI noted its Smart Grid Nova Scotia Project, which was approved by the Board in 2018, and for which NSPI filed its final report in 2024. The Smart Grid Nova Scotia Project included the testing of a distributed energy resource management system (“DERMS”), which included access to resources such as distributed energy resources, electric vehicle smart chargers and managed residential charging, and residential batteries, among other resources.¹⁰⁵ Most resources and programs were tested in providing load smoothing benefits (i.e., flattening a customer’s hourly load profile), though only one resource (commercial and industrial building management systems) was tested for impact on reducing system critical peaks.¹⁰⁶ The tests were largely successful and demonstrated use cases for the DERMS (and the various resources to which it has access) in smoothing load profiles, reducing peak demand, and (for C&I building management systems) reducing system critical peaks.¹⁰⁷ As NSPI noted in its Final Report:

On December 27, 2023, NS Power filed *The Path to 2030* submission. *The Path to 2030*, which is aligned with the province’s *2030 Clean Power Plan*, targets 150 MW of ‘load management’ by 2030 – inclusive of hybrid peak, demand response, energy efficiency, electric vehicle smart charging, etc. The learnings and benefits of the Project are directly applicable to these expanded

¹⁰⁴ 2022-2023 Bates White Audit Report, page 45.

¹⁰⁵ NSPI, “CI C0010778 Smart Grid Nova Scotia Project, Final Report,” March 15, 2024, M09985 (“Smart Grid Nova Scotia Final Report”), page 5.

¹⁰⁶ Smart Grid Nova Scotia Final Report, Table 1.

¹⁰⁷ Smart Grid Nova Scotia Final Report, Appendix F, Attachment 2.

targets. Further, the conclusions of the Project provide a foundation on which to explore opportunities for future permanent deployment of similar innovation capital assets and programs at scale.¹⁰⁸

NSPI's 2025 load forecast noted the high cost of residential batteries (\$15,000-\$20,000 for a 5-7 kW installation) relative to the cost of a gas-powered generator (as low as \$1,000 for a 5-7 kW generator and \$10,000 for a whole-home generator), which limits demand for residential batteries. NSPI noted that its Time Variable Pricing ("TVP") rates, following their pilot process, may encourage more home battery installations. NSPI's latest report on the TVP pilot was issued in July 2024.¹⁰⁹ Participation in the pilot included 2,241 residential time-of-use customers, 922 residential critical peak pricing ("CPP") customers, and 65 commercial customers split between time-of-use and critical peak pricing rates.¹¹⁰ Nine residential CPP events were called during the winter period 2023-2024 with average temperatures of -6.0 degrees Celsius.¹¹¹ The average load reduction in the hours of these events by residential CPP participants was 32.2% relative to participants' reference day average load.¹¹² Results were impacted by household income level and household size, with higher income and larger households showing greater load reduction.¹¹³ Residential time-of-use participants, meanwhile, achieved load reductions of 7.4% during morning peaks and 7.0% during evening peak periods.¹¹⁴

The only other additional rate pilot in place during the Audit Period was the "Multi-Unit Residential Building Time-of-Use Pilot Tariff. NSPI expects to provide its first report on that pilot in the second quarter of 2026.

III.B.1.e. Short-Term Load Forecast

The system operator relies on short-term load forecasts in its day-ahead unit commitment and scheduling processes. NSPI's operations rely on day-ahead, 2-day-ahead, 3-day-ahead, 4-day-ahead, and 5-day-ahead hourly load forecasts developed and updated daily by a third party vendor. The vendor provides a two-week outlook from an artificial neural network model of the hourly demand for NSPI based on hourly load inputs from NSPI and an optimized weather forecast selection procedure. The vendor, which has a 24-hour service desk, provides the forecast as a web-based service and provides hourly data files that are input into the ERM economic dispatch system. The system operator monitors the short-term load forecast on a daily basis for accuracy and interfaces with the vendor for solutions when adjustments or updates are required to maintain acceptable forecast performance. Adjustments may include updating static data (such as the provincial holiday calendar), re-training the model with different

¹⁰⁸ Smart Grid Nova Scotia Final Report, page 7.

¹⁰⁹ NSPI, "Time-Varying Pricing Pilot Program – 2023/24 (Year Three) Evaluation Report," July 31, 2024, M11823 ("TVP Report").

¹¹⁰ TVP Report, Appendix A, Table 5.

¹¹¹ TVP Report, Appendix A, page 21.

¹¹² TVP Report, Appendix A, Table 19.

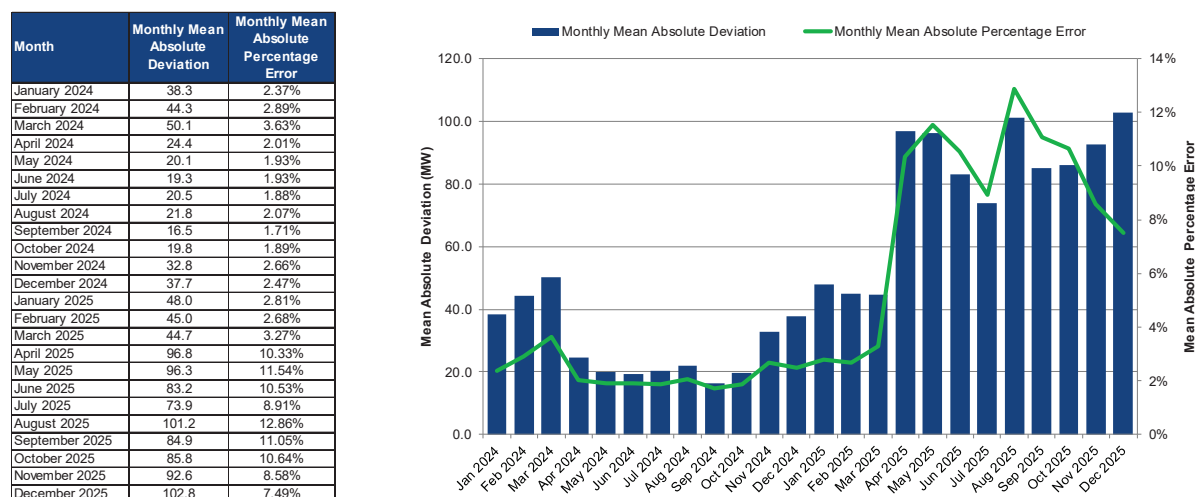
¹¹³ TVP Report, Appendix A, Figure 7.

¹¹⁴ TVP Report, Appendix A, page 9.

input variables, and adjustments for large storm outages that would affect future load predictions. ERM accepts the forecast as vetted by the system operator but can also request that the system operator review forecast model performance if there are concerns about accuracy.

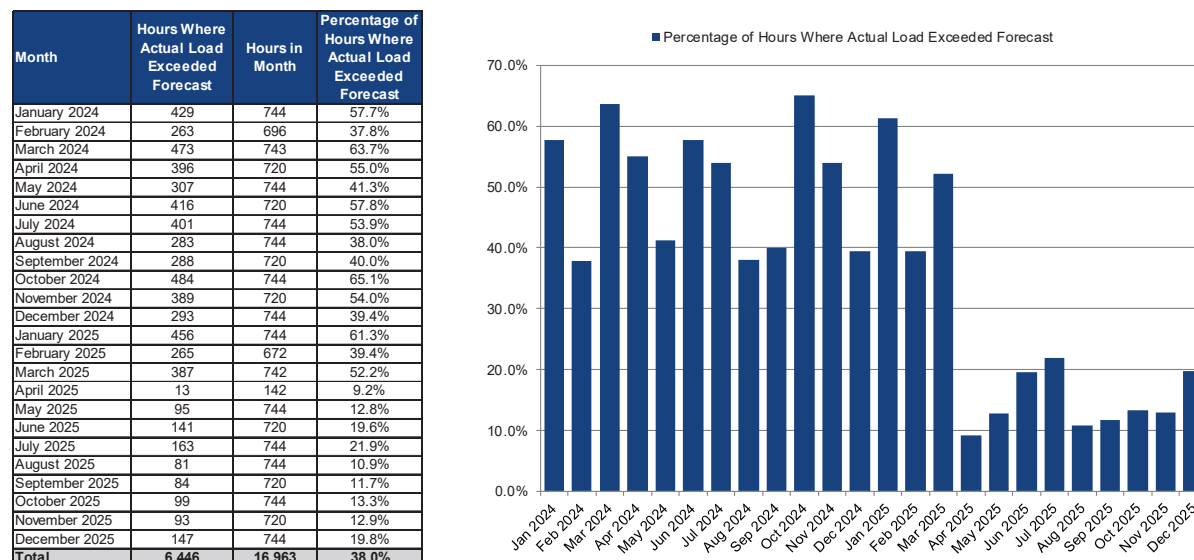
Bates White analyzed the accuracy of the daily day-ahead hourly forecasts by comparing the hourly forecast values to the actual load for the same hour for each day of the 2024-2025 Audit Period. Our review necessarily did not include data for April 1, 2025 (hour ending 01:00) through April 25, 2025 (hour ending 03:00), due to that data not being recoverable by NSPI due to the cyber event. The Monthly Mean Absolute Deviation and Monthly Mean Absolute Percentage Error (“MAPE”) for the Audit Period are shown in Figure III-4. For most of the period (January 2024 through March 2025), the accuracy of the model during the Audit Period is within common utility load forecasting practice, averaging about 2.41 percent during the Audit Period. However, following the cyber event, and beginning with data in April 2025 through the end of the Audit Period, MAPE greatly increased, averaging 10.22% for that period.

Figure III-4: Day-Ahead Forecast Accuracy – All Hours (2024-2025)



To further test the accuracy of the day-ahead forecasts, we assessed whether there was any bias in the forecast, i.e., a tendency to over- or under-estimate load. Again, the results are markedly different for the pre- and post-cyber event periods. As shown in Figure III-5 below, for the pre-cyber event period (January 2024 through March 2025), results showed no evidence of bias, with actual load exceeding forecasted load in 50.5% of all hours. For the post-cyber event period, actual load exceeded forecasted load just 15.2% of the time. In other words, the day-ahead forecast overestimated hourly load in about 85% of hours. This is evidence of substantial bias in the model.

Figure III-5: Percentage of hours where actual load exceeded day-ahead forecast (2024-2025)



Taken together, NSPI’s short-term load forecasts demonstrated bias and high MAPEs in the post-cyber event period. We raised this issue with NSPI, seeking to understand if NSPI intentionally biased their forecasts higher to allow for a margin of safety and ensure reliability. However, NSPI indicated that it had not done so, and that its calculations of MAPEs were in line with historical results. We could not reconcile NSPI’s calculations to our own, and note that we used NSPI’s own data to calculate our MAPE values.

NSPI explained that in the aftermath of the cyber event, the loss of the Process Information (“PI”) system impacted its short-term load forecasting process. Specifically, the short-term load forecasting model lost its automation (from PI) for hourly updates and, as a result, load forecast model updates were done manually. Those updates were completed “a few times per day” instead of automatically throughout the day, and these conditions persisted through the end of the Audit Period.

It appears clear from the data that NSPI’s short-term load forecasts were significantly impacted by the cyber event, and though NSPI denies making any sort of adjustments to bias the model against poor reliability outcomes, the forecasts’ higher MAPE and upward bias suggests NSPI sought to ensure adequate online resources during a challenging period to operate the system. This approach has its merits and occurred in response to a major cyber event that prevented NSPI’s employees from accessing key systems on which they rely each day, such as PI, and processes that are impacted by those offline systems (such as the short-term load forecast). Still, this approach has costs and could, at times, lead to overcommitment of resources. Winter start-up costs for NSPI’s thermal units, for example, range between \$17,795 and \$279,018 per unit, depending on the unit and whether the start is a hot, warm, or cold start. Summer start-up costs are the same for most resources, though lower cost (by about half) for the Tufts Cove units.

III.B.2. Fuel and Purchased Power Forecasting

Fuel and Purchased Power (“F&PP”) forecasts are prepared annually and updated quarterly, or more frequently if there are significant changes that suggest the forecast is no longer reliable (such as pandemics or fuel/commodity market disruptions due to geopolitical disturbances). The results of these forecasts are used in fuel purchasing and the review and rebalancing of the hedging plan. F&PP forecasts are conducted using PLEXOS. The F&PP forecasting methodology, approach, and process remained largely unchanged since the previous audit period. NSPI retained access to PLEXOS throughout the Audit Period, even after the cyber event, though this was a fortuitous result: NSPI explained that while it lost institutional access to PLEXOS, the Portfolio Optimization team was able to locate a recent PLEXOS model and data set on a local disk, which allowed NSPI to continue using PLEXOS without any disruptions. (In fact, as explained in the Commitment and Dispatch chapter, NSPI employed PLEXOS as an alternative to PortOps in committing and dispatching the system, given the loss of access to PortOps following the cyber event.)

The F&PP forecasting process consists of two distinct components: PLEXOS dispatch simulation modelling and financial model production. This section of the report covers only the methodology, data sources, and results of the PLEXOS forecast. The results of the PLEXOS dispatch simulation modelling provide the quantities of the various fuels required to supply the forecast load at the lowest possible cost. The Senior Manager of Fuels Planning and Performance (Finance) is responsible for producing the forecasts, which are reviewed with the ERM and Portfolio Optimization management and the FST, as per the Fuel Manual.

As stated above, the PLEXOS forecast of the amount of each fuel required to operate the generating units over the forecast period takes into consideration the technical and economic characteristics of NSPI’s generating units, a price forecast for each of the fuels and additives used in generation, alternative fuel blends and associated emissions, various assumptions regarding NSPI’s units’ operation, purchased power costs, and the topology and capacity of the transmission system. One improvement made to the PLEXOS model during the Audit Period was the implementation of a dynamic operating reserve margin, which dynamically adjusts the needed level of operating reserves on the system based on a formula that incorporates the respective standard deviations of hourly wind forecasts. In other words, as expected wind and/or load becomes less certain, PLEXOS increases the amount of operating reserves needed for a reliable model solution (and vice versa if load/wind forecast uncertainty decline). This improves upon the prior method, which specified a static operating reserve margin for all modeled hours. NSPI also implemented this improvement for PortOps. This feature will become more useful as additional wind is added to the system.

In its 10-Year System Outlook, NSPI relies on PLEXOS to forecast the long-term utilization of its thermal generating fleet.¹¹⁵ The forecast of each generating unit Utilization Factor (“UF”) over the 10-

¹¹⁵ NSPI, “2025 10-Year System Outlook,” July 14, 2025 (“2025 10-Year System Outlook”), Figure 11.

year plan, in addition to accounting for future changes in the Nova Scotia power grid over the forecast period, requires a schedule of generating unit additions and retirements, as well as a transmission expansion plan.¹¹⁶ The 10-Year System Outlook report does not explicitly discuss nor document whether the resulting system plan and unit utilization forecast represents the plan with the lowest production cost of a number of alternative resource plans considered by NSPI.¹¹⁷ (NSPI's integrated resource planning efforts aim to determine the long-term, lowest-cost portfolios.) As of December 2025, integrated resource planning is now under the purview of the IESO, not NSPI, meaning all IRP-related efforts (including the 10-year System Outlook) will no longer be NSPI's responsibility going forward.

III.B.2.a. Inputs and Assumptions used with PLEXOS in Fuel and Purchased Power Forecasting

To accurately simulate the operation of the NSPI system, including accurate modelling of the transmission security constraints limiting the economic dispatch of its generating units and its imports and exports, PLEXOS requires highly detailed information about the following:

- System load forecast, which includes hourly power requirements for the forecast period (ten years for the 10-Year System Outlook, two years for the FAM forecasts, and one week for day-ahead unit commitment and dispatch);
- Transmission characteristics, including nodal system configuration and individual transmission line characteristics;
- Fuel-price forecasts, which provide an estimate of the delivered price of each fuel to NSPI for each of NSPI's generating plants, over the forecast horizon, using contract prices for fuel and transportation already contracted and forward-market prices for fuel and transportation not yet contracted;
- NSPI's generating unit characteristics and availability, including heat rates, programmed maintenance outages, maximum capacities, deration factors, DAFOR, variable O&M costs, and mercury abatement costs;
- Other operating costs, such as solid fuel pile management costs, rail car leases, pier volume adjustments, and incremental trucking costs;
- Emission assumptions including: emissions targets, Hg diversion credits forecast, NOx parameters, SO₂ removal costs, Hg removal, and GHG shadow price (or OBPS price) and GHG limits, including the potential to use emissions compliance buffers;

¹¹⁶ 2025 10-Year System Outlook, pages 26 to 27.

¹¹⁷ 2025 10-Year System Outlook, pages 26 to 27.

- Volume and price assumptions for power exports and power imports. Export energy to New Brunswick is modeled as energy oversupply sales represented in PLEXOS [REDACTED] [REDACTED] \$/MWh, which is later replaced by New England Power Pool's Hub prices in the financial model. Import prices from New Brunswick are priced at the New England Power Pool's Hub adjusted for transmission costs to the Nova Scotia border and limited to the three-year average of annual import energy. Import energy volumes of Muskrat Falls Base block and Supplemental block are appropriately modeled using \$0 price. Surplus energy is modeled based on on-peak and off-peak forward day-ahead prices for the New England Power Pool's Massachusetts Hub.
- Wind and hydroelectric monthly production is estimated outside of PLEXOS, based on historical information and entered into PLEXOS. Monthly wind energy production profiles are based on averages of the last three years' production data for each telemetered wind project or based on the geographically nearest telemetered wind site. The hourly wind generation profiles are based on the previous year hourly wind profile coincident with the hourly load profile and input into PLEXOS together with monthly energy and peak generation forecast information for each wind generator. Hydroelectric production estimates for each unit use a 23-year rolling average, adjusting the average for unit additions, decommissioning, and extended unavailability for inspections and maintenance. Historical monthly hydro system energy averages are qualified in PLEXOS by the daily and weekly production restrictions representing water flow restrictions and reservoir capabilities including, riparian flows, fish ladder flows, required reservoir levels, etc. The run of river systems are modeled as fixed output profiles to represent the non-dispatchable nature of such systems. As we have pointed out in the past, the use of historical hydroelectric production data to forecast production from these resources assumes a certain regularity in Nova Scotia weather patterns which may not hold true over the long term.¹¹⁸ While the 23 years of hydroelectric history provides a reasonably large enough sample of precipitation variation over time, the impact of climate change may be increasingly felt as reduced annual precipitation and a change in the intensity and frequency of storms, with different effects on impounded and run of river hydroelectric facilities.¹¹⁹

III.B.2.b. Environmental Considerations in Unit Commitment and Dispatch Forecasting

NSPI is subject to air quality regulations that dictate its fleetwide emissions of SO₂, NO_x, mercury, and GHGs. NSPI's F&PP forecasts incorporate these limitations to ensure its modeling results are consistent with environmental regulations. PLEXOS is used by the Portfolio Optimization Group to perform optimized annual and quarterly forecasts of generation dispatch and fuel use. NSPI's day-to-day

¹¹⁸ 2020-2021 Bates White Audit Report, page 48.

¹¹⁹ Government of Nova Scotia, "Climate Impacts", available at: <https://climatechange.novascotia.ca/climate-impacts>

commitment and dispatch decisions aim to keep NSPI on target to meet these limitations in practice. PortOps is used to plan the daily dispatch through the modeling of the incremental cost of consuming powder activated carbon (to control mercury emissions), use of coal price adders to stratify coal pricing based on sulphur content, and dispatch price adders for the cost of GHG emissions.

NSPI manages SO₂ emissions limits through its blending of solid fuels. In the F&PP forecast, NSPI models SO₂ emissions constraints as a “not-to-exceed” constraint, whereby the PLEXOS model results do not violate the specified SO₂ emissions constraints in place. Mercury emissions are managed differently—NSPI uses powder activated carbon (“PAC”) injection to reduce mercury emissions. PLEXOS modeling of mercury constraints is done through adding PAC costs and the corresponding mercury abatement rates based on expected coal fleet dispatch. Optimal use of PAC to achieve Hg emissions limits is calculated outside of PLEXOS by the Emissions Compliance Engineer in order to ensure compliance with regulations.

If emissions estimates reported by NSPI’s Environmental Services group deviate from previously reported estimated emissions releases, the Portfolio Optimization, Fuels, and Environmental Services teams meet and review emissions compliance options. If the magnitude of a deviation is likely to result in a material change to required dispatch to meet environmental requirements, the team discusses the necessity of a new PLEXOS run. If a new dispatch optimization is required, a PLEXOS run is executed to help guide emissions compliance. Based on the PLEXOS dispatch optimization, the Fuels team may adjust fuel blends and either rebalance hedges or issue RFPs for additional energy imports or natural gas quantities to ensure emissions compliance.

Regarding GHG emissions, NSPI was subject to the Output Based Pricing System (“OBPS”).¹²⁰ The OBPS program requires NSPI to purchase GHG fund credits from the province if GHG emissions exceeded specified emissions intensities for a given plant (based on its fuel type), and rewards performance credits (which may be netted against fund credits) to generating units that emit at GHG intensities below specified limits. (We address the details of the intensities in chapters X and XI.) OBPS cost adders ranged from \$■■■■/MWh (Lingan, 2024) to \$■■■■/MWh (Burnside, 2025). Some OBPS “adders” were negative, i.e., output from such units generated OBPS credits, which ranged from \$■■■■/MWh (Trenton, 2024) to \$■■■■/MWh (PHB, 2025).

To model the OBPS program, each MWh of electricity generated was subject to either GHG fund or performance credits. For example, if a gaseous fuel plant releases 0.60 tonnes of GHG per MWh, and the OBPS allowance is 0.37 tonnes of GHG per MWh, then each MWh of electricity generated by that plant is subject to $0.60 - 0.37 = 0.23$ tonnes of GHG fund credits per MWh, or $0.23 * \$95/\text{tonne of GHG in 2025} = \$21.85/\text{MWh}$. Thus, the unit would be subject to a cost adder of \$21.85/MWh.

¹²⁰ Climate Change Nova Scotia, “Nova Scotia’s Output-based Pricing System for Industry,” available at: <https://climatechange.novascotia.ca/output-based-pricing-system>.

III.B.2.c. Estimation Tracking and Verification of Emissions Compliance at NSPI

The NSPI Environmental Services team estimates emissions monthly. Adjustment to SO₂ emissions occurs following month end if there is an instrumentation failure or QA/QC requirements are not met. The Quality Assurance (“QA”) and Quality Control (“QC”) requirements are documented in NSPI’s Continuous Emissions Monitoring Systems Quality Assurance Policy. Adjustments may also be made to emissions following the receipt of results from a semi-annual accuracy testing conducted by third-parties. Emissions are verified annually by March 31 of the following calendar year by a third-party.

III.B.2.d. Safeguards to prevent errors in past emissions data entering PLEXOS

Emissions estimates are made available to Fuels Planning the month following based on the best available information. The data is finalized and verified by a third-party in the first quarter following the end of the year as required by environmental regulations. The monthly emissions report from Environmental Services is issued approximately three weeks following the end of the month. In the interim, Portfolio Optimization produces an estimate of year-to-date system emissions based on fuel consumption and fuel emissions parameters. The Environmental Services month-end emissions estimate is regularly compared to the Portfolio Optimization interim estimate, and any discrepancies are discussed in the monthly emissions compliance meetings.¹²¹

PLEXOS intra-year dispatch optimization simulations receive a single data point entry quantifying the SO₂ emissions allotment for the remainder of the year. That allotment is determined by subtracting the year-to-date emissions estimate from the annual allowable emission. The PLEXOS data entry process is not automated, but the figures are reviewed by the Emissions Compliance Engineer. The resulting optimization, together with the PLEXOS emissions output, undergoes a quality assurance check by the Emissions Compliance Engineer, as well as a review by the ERM teams, who check the emissions against the historical values, previous forecasts, and fleet capabilities, to make sure the values are within an expected and acceptable range.

While these procedures should prevent clearly erroneous emissions compliance data from being fed into PLEXOS, when errors fall within the ranges set to trigger a review of the data and ERM has concerns about emissions compliance data and or revisions to past emissions data (and these concerns are not satisfactorily addressed by Environmental Services), a mechanism is in place to escalate the concerns to the appropriate level of management to resolve the issue.

III.B.2.e. PLEXOS Input Information Origination and Maintenance

Appendix B of the FAM Plan of Administration documents the FAM Fuel Forecasting Methodology governing the process and assumptions used by NSPI to produce the fuel forecast required to establish the Base Cost of Fuel (“BCF”). The document specifies the manner and sources of many of the parameters and assumptions used in PLEXOS; it also refers to the schedule to update the associated values. The

¹²¹ 2020-2021 Bates White Audit Report, page 51.

various parameters are updated by various NSPI subject matter experts identified in the list of assumptions on a periodic basis or on demand as required by observed and/or expected changes in system operation. The assumptions update check-sheet used through the Audit Period is illustrated later in this chapter in Figure III-6.

Enterprise Asset Management (“EAM”) supplies all operating characteristics of generating units, including heat rates, forced outage rates, variable O&M costs, fuel switching capabilities, maximum capacities, and expected wind hourly generation profiles. ERM provides fuel prices and physical limits based on market availability and inventory/logistics constraints. The development of pricing assumptions follows the FAM Plan of Administration. Startup costs and times are provided to System Planning by the ERM group and are consistent with what is currently used in the PortOps day-ahead unit commitment and dispatch model.

Only relatively short duration outages—such as those included in the modeled DAFOR rate—are modeled in PLEXOS; major unplanned outages are excluded for modelling purposes, as they would otherwise have the potential to unduly influence simulation results. Ramp rates are maintained by EAM for the steady state F&PP forecasts and provided by the System Operator to ERM if there are temporary deviations from the steady state parameters. If the temporary ramp rates revisions are to persist and become a steady state condition, PLEXOS will be updated to reflect the new reality, and should be consistent with what is currently modeled in PortOps.

PLEXOS currently models five types of operating reserves for the NSPI system: Regulation Up, Regulation Down, Ten-Minute Spin, Ten-Minute Non-Spin, and 30-Minute Non-Spin. The total of Spinning and Ten-Minute Non-Spin reserves reflects NSPI’s 168 MW operating reserve commitment to the Maritimes Region reserve requirement under Northeast Power Coordinating Council (“NPCC”) and the North American Electric Reliability Corporation (“NERC”) operating guidelines, and reflects NSPI’s single largest contingency (Point Aconi’s net output). NSPI carries 50 MW of 30-Minute Non-Spinning Reserve and 16 MW each of both Regulation Up and Regulation Down.

In addition to explicit operating reserve requirements, NSPI also is required to meet other reliability requirements, which it addresses in its F&PP PLEXOS forecasting. The minimum steam unit commitment parameters currently modeled in PLEXOS are set by the NS System Operator. The NSPI PLEXOS model also incorporates a dynamic requirement for Metro Dynamic Reactive Reserve, where the hourly reserve requirement in mega volt ampere reactive power (“MVAR”) is calculated based on Onslow South corridor flow and total system load. Linearized unit capability curves for the metro units (Tufts Cove and Burnside) are in the model to properly reflect the inverse relationship between unit dispatch level and available generator MVAR. The NSPI Transmission Planning group updates these

Metro Dynamic Reactive Reserve requirements periodically as system configurations change (e.g., capacitor bank modifications, transmission node configurations).¹²²

III.B.2.f. Input Parameter Validation

Some PLEXOS input parameters are subject to regular review within NSPI or are provided by the Nova Scotia System Operator, including System Reserve Requirements and Minimum Unit Commitment Constraints. Other PLEXOS input parameters are maintained by EAM or ERM and are updated in PLEXOS as needed to be consistent with PortOps, including unit start-up costs and unit ramp rates. Still, other PLEXOS input parameters are model calibration values, set to achieve the model behavior that reflects the general fleet dispatch constraints under normal operation. These are updated as those operating behaviors change in the future, including minimum up or down times for steam units and forced outage repair times. We reviewed the parameters and provide the results in the following figure.

Figure III-6: PLEXOS Assumptions – Q4 2025 Fuel and Purchased Power Forecast

Group	PLEXOS Assumptions	Update Required	Notes	Update Received Date
Load	Base Load forecast - Monthly demand and energy	Yes	Load unchanged from previous in 2026 and 2027, new file provided to include 2028.	11/24/2025
	ELIADC forecast - Monthly demand and energy	No	PHP Load remains unchanged from AAR forecast.	9/30/2025
	Load nodal distribution	No	Updated in July 2015.	2015-07
Hydro	Hydro – monthly generation profile by hydro system	No	Based on 23-year average production	2025-Q1
	Hydro system dispatch constraints	No	Provided by ECC – No Change	2016-Q1
	Tidal storage (Annapolis) – energy	No	Unit offline	Permanent
	Tidal storage (Annapolis) hourly profile	No	Unit offline	Permanent
	Wreck Cove LEM (Life Extension Modernization)	Yes	As per updated GMS	2025-Q4
Generation Planning	Power Production Maintenance Schedule	Yes	As per updated GMS	2025-Q4
	Unit maximum and minimum capacities / monthly derations	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Unit DAFOR (Deration adjusted forced outage rate)	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2

¹²² PLEXOS, like other production modelling tools relies on a DC approximation to save execution time when modelling the power flows in the transmission system; thus using a linearized equation to model the relationship between generating unit dispatch and available reactive power from the same unit.

Group	PLEXOS Assumptions	Update Required	Notes	Update Received Date
	DAFOR estimated repair times and distribution	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Unit heat rates	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Unit variable O&M cost	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Unit operating restrictions / constraints	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Generating unit start-up costs / shut down penalties	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Generating unit ramp rates	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
	Generating unit minimum up and down times	No	Updated from the unit performance modeling datasheet, as required.	2025-Q2
IPP & COMFIT	IPP - monthly energy/capacity	No	Update as required. Updated in Q1 and Q3.	2025-Q3
	COMFIT	No	Update as required. Updated in Q1 and Q3.	2025-Q3
	COMFIT nodal distribution	No	Based on geographic distribution of COMFIT generators	2023-Q1
	NSPI Owned Wind monthly energy/capacity	No	Update as required. Updated in Q1 and Q3.	2025-Q3
	NSPI/IPP/COMFIT Wind Curtailment / dispatchability matrix	No	Not used: TX connected wind curtailable – COMFIT not curtailable	Permanent
	Tidal flow through – energy	No	Flow through tidal forecast is at 0 GWh	Permanent
	Tidal flow through - hourly profile	No	Updated 2016-Q3 (Work done by Bizo in 2016)	2016-Q3
	Wind hourly profile	No	Updated Annually in Q1, 2023 Used, cyber incident	2025Q2
	Solar hourly profile	No	Based on Amherst Solar Data	2024
Fuel and Market	Natural Gas, HFO, LFO Prices	Yes	Update Quarterly	10/31/2025
	Natural Gas, HFO, LFO volumetric contracts/constraints	No	Update as required, no changes noted.	2025-10-31
	Natural Gas Carbon Content	No	Unchanged.	2019-05
	Solid fuel prices	Yes	Update Quarterly	10/31/2025
	Coal blends restrictions – volume, calorific value	Yes	Update may be required due to operational constraints.	11/4/2025
	Coal emissions content	Yes	Updated Quarterly	11/4/2025

Group	PLEXOS Assumptions	Update Required	Notes	Update Received Date
	Biomass cost and energy availability profile	No	Update as required.	2025-Q3
	Pt. Aconi ash and limestone cost and consumption	No	Updated annually in Q1	2025-Q1
	Hg abatement – PAC performance and cost	No	Abatement cost calculated outside of the model and supplied to the model. Reviewed, no changes.	2025-Q2
Fuel and Market	NB Exports	No	Modeled as low price to represent wind oversupply	Permanent
	NB Imports	No	Confirm 3 yr avg or document deviation, updated at least annually	2025-Q1
	NB model	No	NB model represented by a market	Permanent
	NE model	No	NE represented by a fixed contract node to allow ML Surplus flow through	Permanent
Fuel and Market (Maritime Link)	ML NS Block	No		Permanent
	ML Supplemental Block	No		Permanent
	ML Surplus Energy	Yes	Update as required.	2025-Q4
	ML Make up energy	Yes	Update as required.	2025-Q4
	Maximum Energy keep / simultaneous NB/NL imports	No	As per discussion with ECC	Permanent
Emission Assumptions	Emissions targets / assumptions	Yes	Update partial year limits based on YTD emissions	2025-Q4
	Hg diversion credits forecast	No	Application of Hg Diversion program credits 2020-2029 up to 10kg available.	Permanent
	NOx parameters	No	Low Nox burners characteristics. No update.	Permanent
	SO ₂ precipitator removal	No	No update.	2020-04
	Hg precipitator removal (native capture)	No	POA native capture Updated as Required.	2025-Q2
	GHG Shadow price / GHG limits	No	Cap-and-trade replaced by OBPS.	Permanent
	OBPS	No	No Changes needed.	Permanent
System Constraints	Minimum Steam generation commitment	No	Confirmed by ECC, CB steam updated to 1 in Q3 2025	2025-Q3
	Reserve – Regulation	No	2025-Q4 – ECC confirmed no update	2023-Q1
	Reserve – Spinning	No	2025-Q4 – ECC confirmed no update	2023-Q1
	Reserve – 10-minute	No	2025-Q4 – ECC confirmed no update	2023-Q1

Group	PLEXOS Assumptions	Update Required	Notes	Update Received Date
	Reserve – Deliverability Constraint	No	All reserve needs to be deliverable to east of Onslow – adjusted for ONI capacity	2023-Q1
	Wind Maximum proportion of load constraint	No	50% of total system load	2023-Q1
	NB Imports maximum % of system demand	No	27% of total system load	2023-Q1
	Simultaneous NB/ML import curve	No	Function of NS, PEI and ML flow needed.	Permanent
	Additional reserve for ML flows above threshold	No	$475 - (475 - (475/2) - 168) = 405.5$ MW (one for one increment).	Permanent
Transmission Constraints	Metro Reactive Reserve Requirement (MDRR)	No	Model updated by System Planning	2020-04
	Cape Breton Export SPS Dispatch constraint	No	Post ML link values in effect – Assumptions by ECC	2019-01
	Line/Corridor/Interface transfer capabilities	No	ONI updated by Bob Creighton	2020-04
	Line Impedances	No	Not used in the model – losses modeled as part of load forecast	2019-07
	System interconnectedness diagram	No	Post ML system configuration	Post-ML

III.B.3. Accuracy of Fuel and Purchased Power Forecasting

Figure III-7: Comparison of Actual vs. Forecast Fuel Costs (2024) ¹²³

	Actual	Forecast	\$ Variance	% Variance
Solid Fuel Cost	\$319,034,892	\$265,660,172	\$53,374,720	20.09%
Natural Gas Cost	\$148,275,704	\$109,186,050	\$39,089,654	35.80%
Biomass Cost	\$17,125,986	\$18,859,896	(\$1,733,910)	-9.19%
Bunker C Cost	\$22,506,123	\$9,178,443	\$13,327,680	145.21%
Diesel Cost	\$7,063,537	\$11,300,899	(\$4,237,362)	-37.50%
Furnace Cost	\$6,301,606	\$2,047,111	\$4,254,495	207.83%
Additives	\$3,726,983	\$1,375,090	\$2,351,893	171.04%
Additives - Hg	\$9,813,201	\$3,474,913	\$6,338,288	182.40%
Total Consumed Costs	\$533,848,032	\$421,082,574	\$112,765,458	26.78%

¹²³ Q4 2024 FAM Report, 3(3).

Figure III-8: Comparison of Actual vs. Forecast Fuel Costs (2025)¹²⁴

	Actual	Forecast	\$ Variance	% Variance
Solid Fuel Cost	\$321,602,838	\$291,312,788	\$30,290,050	10.40%
Natural Gas Cost	\$121,804,288	\$176,366,243	(\$54,561,955)	-30.94%
Biomass Cost	\$19,323,948	\$18,754,719	\$569,229	3.04%
Bunker C Cost	\$50,908,007	\$7,000,998	\$43,907,009	627.15%
Diesel Cost	\$9,350,705	\$5,108,367	\$4,242,338	83.05%
Furnace Cost	\$5,455,326	\$4,383,909	\$1,071,417	24.44%
Additives	\$3,092,941	\$4,872,098	(\$1,779,157)	-36.52%
Additives - Hg	\$11,825,782	\$7,546,486	\$4,279,296	56.71%
Total Consumed Costs	\$543,363,836	\$515,345,608	\$28,018,229	5.44%

Figure III-7 and Figure III-8 above show observed variances between NSPI's actual fuel costs from its forecast fuel costs, by fuel, over the two year 2024-2025 Audit Period. In 2024, the overall variance was 26.8%, or \$112.8 million, a significant deviation from the forecast. In 2025, the forecast was much closer to actual costs, with an overall variance of \$28.0 million, or 5.4%.¹²⁵

There were contributing factors to these deviations that were outside of NSPI's control. For example, Surplus Energy from Muskrat Falls was lower than forecasted. This can be seen in the "Imports" row of the following two figures. In 2024, in particular, NSPI received just 1.1 TWh of imports, about 53% less than the 2.3 TWh forecasted. This "missing" 1.2 TWh required replacement from other generation sources. In addition, renewable resources underperformed forecasts. This included both NSPI's owned renewables, which produced 24% and 22% below forecasts in 2024 and 2025, respectively, and (in 2024 only) third-party renewables, including third-party wind and COMFIT resources. Again, this missing generation required replacement. Figure III-9 and Figure III-10 compare the PLEXOS forecasted supply budget by resource (NSPI generating unit or purchased power source) to the actual volume of energy supplied by that resource.

¹²⁴ Q4 2025 FAM Report, 3(3).

¹²⁵ 2024 and 2025 Q4 FAM Reports, Tab 3(3).

Figure III-9: Comparison of Forecast Budgets vs. Actual Supply by Resource (2024) (MWh)¹²⁶

Detail	Actual	FAM Budget	Variance	Variance (%)
Generation				
Lingan	1,559,503.40	1,541,984.50	17,518.90	1.14%
Tufts Cove	1,614,389.19	557,559.58	1,056,829.61	189.55%
Trenton	858,243.66	771,548.28	86,695.38	11.24%
Point Tupper	563,036.29	220,704.40	342,331.89	155.11%
Point Aconi	782,438.05	425,927.02	356,511.03	83.70%
Combustion Turbines	15,110.98	32,615.58	(17,504.60)	-53.67%
LM6000	754,903.59	789,212.32	(34,308.72)	-4.35%
Renewables	1,094,559.88	1,431,066.19	(336,506.31)	-23.51%
Total Generation	7,242,185.05	5,770,617.87	1,471,567.19	25.50%
Purchased Power				
Imports	1,075,238.00	2,250,924.52	(1,175,686.52)	-52.23%
IPP	258,989.69	223,034.40	35,955.29	16.12%
Maritime Link	1,377,693.47	1,134,000.00	243,693.47	21.49%
Wind	879,092.61	1,327,123.57	(448,030.96)	-33.76%
COMFIT	493,120.92	534,353.90	(41,232.98)	-7.72%
Total Purchases	4,084,134.69	5,469,436.38	(1,385,301.70)	-25.33%
Total MWhs Available				
Total MWhs Available	11,326,319.74	11,240,054.25	86,265.49	0.77%
Other Data				
Domestic Revenue	10,580,582.95	N/A	N/A	N/A
Exports	0.00	N/A	N/A	N/A
Total Electric Revenue	10,580,582.95	N/A	N/A	N/A
Line and Other Losses	745,736.79	N/A	N/A	N/A

¹²⁶ Q4 2024 FAM Report, 8(3).

Figure III-10: Comparison of Forecast Budgets vs. Actual Supply by Resource (2025) (MWh)¹²⁷

Detail	Actual	FAM Budget	Variance	Variance (%)
Generation				
Lingan	2,195,760.27	1,413,123.10	782,637.16	55.38%
Tufts Cove	978,803.66	1,310,053.96	(331,250.30)	-25.29%
Trenton	1,127,222.43	1,134,507.47	(7,285.03)	-0.64%
Point Tupper	690,323.40	192,336.04	497,987.36	258.92%
Point Aconi	670,856.83	1,057,463.62	(386,606.79)	-36.56%
Combustion Turbines	20,255.72	14,615.68	5,640.04	38.59%
LM6000	653,118.73	748,981.24	(95,862.51)	-12.80%
Renewables	1,039,415.83	1,331,411.46	(291,995.63)	-21.93%
Total Generation	7,375,756.86	7,202,492.57	173,264.29	2.41%
Purchased Power				
Imports	1,237,725.62	1,536,545.14	(298,819.52)	-19.45%
IPP	314,307.88	198,402.79	115,905.09	58.42%
Maritime Link	1,133,957.67	1,134,000.00	(42.33)	0.00%
Wind	964,016.31	975,445.73	(11,429.42)	-1.17%
COMFIT	502,303.42	494,334.65	7,968.77	1.61%
Total Purchases	4,152,310.90	4,338,728.32	(186,417.42)	-4.30%
Total MWhs Available				
Total MWhs Available	11,528,067.76	11,541,220.88	(13,153.13)	-0.11%
Other Data				
Domestic Revenue	10,705,091.07	N/A	N/A	N/A
Exports	4,528.00	N/A	N/A	N/A
Total Electric Revenue	10,709,619.07	N/A	N/A	N/A
Line and Other Losses	818,448.69	N/A	N/A	N/A

III.B.4. Bates White's 2022-2023 Audit Recommendations

We made no recommendations regarding Forecasting and Fuel Supply Planning in our prior Audit Report.

III.C. Conclusions

Conclusion III-1: NSPI's load forecasting approach remains largely unchanged from the prior audit period. NSPI continues to file an annual 10-year load forecast with the Board and allows for stakeholder involvement in the process.

Conclusion III-2: The 2025 Load Forecast Report expects average annual forecasted *decreases* in net system requirement of 0.2 percent over the 2025-2035 period. Migration to RTR load, electrification of

¹²⁷ Q4 2025 FAM Report, 8(3).

transportation and heating, behind-the-meter solar, and DSM growth all contribute to this forecasted decrease.

Conclusion III-3: The SAE models NSPI used in its forecasting of residential and commercial load remain well suited to accommodate the growing penetration of energy-efficient and demand-response technologies and improvements of these technologies over time.

Conclusion III-4: NSPI's 2024 actual peak load (2,088 MW) was 6.2 percent lower than forecast (2,225 MW). Similarly, in 2025, NSPI's actual peak load (2,267 MW) was 6.1 percent lower than forecast (2,415 MW). These moderate over-forecasted peaks resume a trend observed since 2020 in which NSPI's forecasted annual peak load exceeded actual peak load. These data should not necessarily be a cause for alarm but suggest caution in making long-term decisions based on a single year peak demand forecast values.

Conclusion III-5: NSPI completed and reported on pilot programs that are designed in part to limit peak demand, including its DERMS project, TVP rates, and CPP program. The DERMS pilot demonstrated use cases for the DERMS (and the various resources to which it has access) in smoothing load profiles, reducing peak demand, and (for C&I building management systems) reducing system critical peaks. Residential time-of-use participants reduced load by 7.4% during morning peaks and 7.0% during evening peak periods, while residential CPP participants reduced load during CPP events 32.2% relative to participants' reference day average load.

Conclusion III-6: For most of the period (January 2024 through March 2025), the accuracy of NSPI's short-term load forecasting model's accuracy was within common utility load forecasting practice, averaging about 2.41 percent during the Audit Period while exhibiting no bias. Due to the cyber event, data for April 1, 2025 through April 25, 2025 was not provided as it was unrecoverable.

Conclusion III-7: For the period April 25, 2025 through the end of the Audit Period, NSPI's short-term load forecasts' accuracy declined significantly and exhibited bias. Specifically, the forecasts' MAPE greatly increased, averaging 10.22% for that period, while the forecasted load exceeded actual load 84.8% of the time. NSPI provided its own MAPE results that do not match our MAPE calculations, which were calculated using NSPI's own data.

Conclusion III-8: Further to Conclusion III-7, in the aftermath of the cyber event, the short-term load forecasting model lost its automation (from PI) for hourly updates and, as a result, load forecast model updates were done manually and less frequently. While NSPI denies biasing the forecasts to ensure daily reliability, the data suggests otherwise, and we see merit in ensuring sufficient online resources during such a challenging operational period. Still, this approach has costs and could, at times, lead to overcommitment of resources, such as excess start-up costs, which range between \$17,795 and \$279,018 per unit, depending on the unit and whether the start is a hot, warm, or cold start.

Conclusion III-9: NSPI continues to rely on PLEXOS for its F&PP forecasting and maintains updated input parameters to encourage greater accuracy and usefulness of its F&PP forecasts. PLEXOS was used as well in NSPI's 10-Year System Outlooks and IRP processes, though that system planning role has been transferred from NSPI to the IESO as of December 2025.

Conclusion III-10: NSPI retained reasonable methods of account for emissions constraints in its forecasting and planning efforts, including use of modeling dispatch price adders, fuel adders (e.g., PAC), and fuel blend assumptions, while also modeling the GHG intensities of its plants and the OBPS costs and credits they generate.

Conclusion III-11: NSPI also continued use of reasonable QA, QC, and verification processes to prevent errors in emissions data tracking and reporting.

Conclusion III-12: In 2024, the overall variance between forecasted and actual fuel costs was 26.8%, or \$112.8 million, a significant deviation from the forecast. In 2025, the forecast was much closer to actual costs, with an overall variance of \$28.0 million, or 5.4%. External factors outside NSPI's control contributed to this forecast error, including lower-than-forecasted Surplus Energy and renewable energy from third parties and NSPI's own generation.

III.D. Recommendations

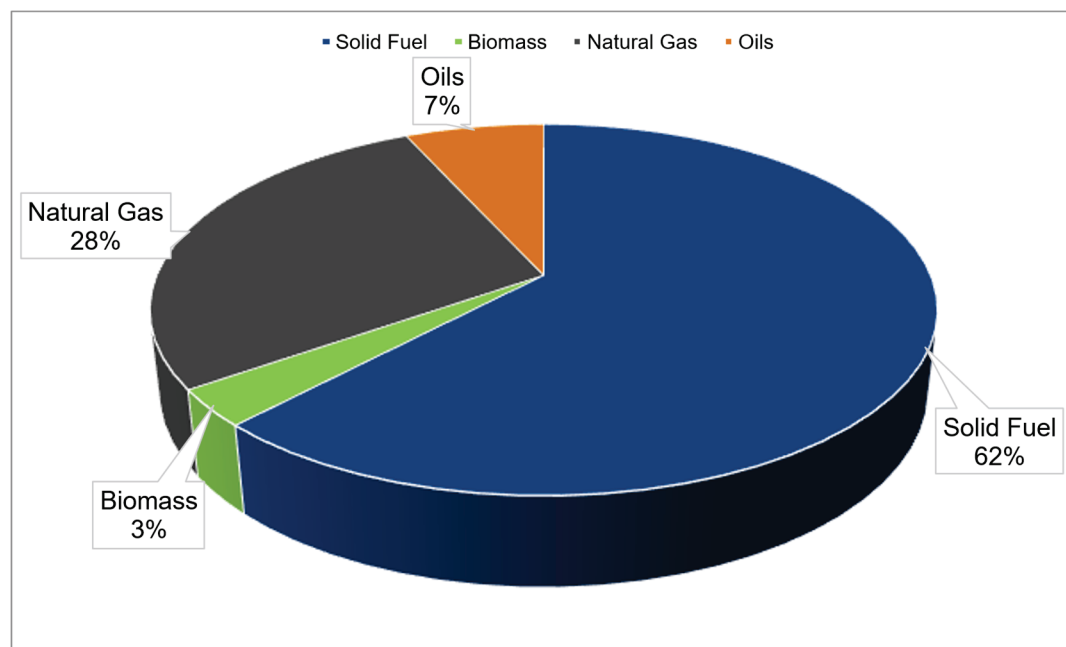
None.

IV. Solid Fuel Procurement and Contracts

IV.A. Background

Solid fuel—i.e., coal and petcoke—has historically been NSPI's largest fuel expenditure. The same remained true in this Audit Period. Figure IV-1 and Figure IV-2 show that for both 2024 and 2025, solid fuel accounted for 62% of all NSPI's expenses for fuel purchases that are burned for the purposes of generating electricity.¹²⁸ More broadly, of the \$2.060 billion in gross total FAM expenditures during this Audit Period,¹²⁹ \$696.7 million (or about 34%) were spent on solid fuel costs, including additives burned at solid fuel-fired plants.

Figure IV-1: Percentages of Total Fuel Expense among Four Major Categories of NSPI's Fuel (2024)¹³⁰

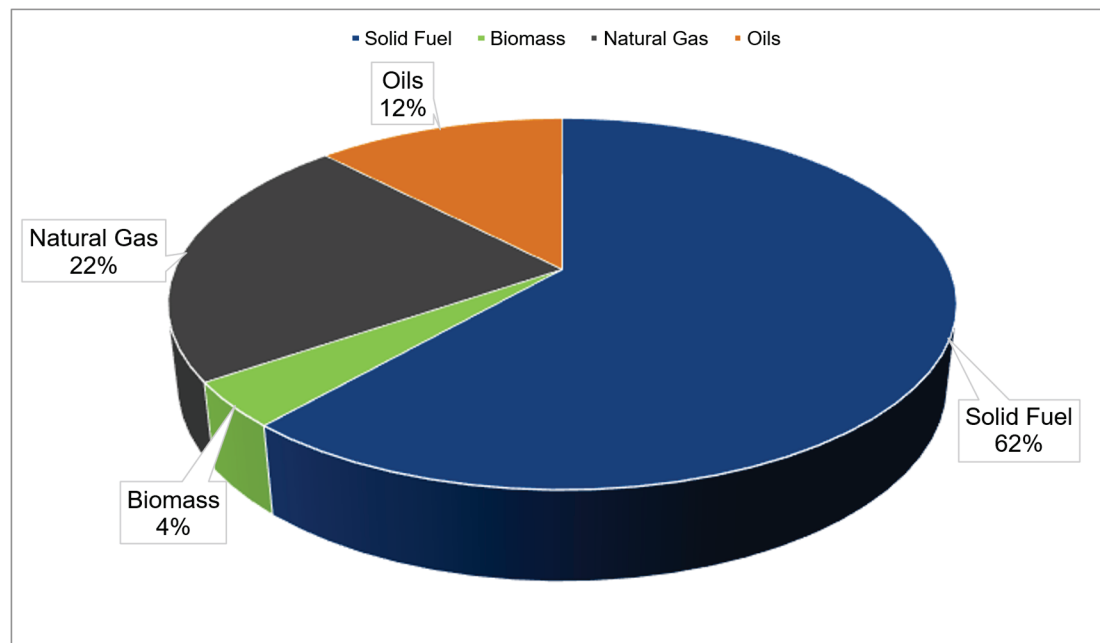


¹²⁸ Figures IV-1 and IV-2 do not include other FAM expenses, such as those for purchased power, or additives to the power generating process (e.g., powder-activated carbon), etc.

¹²⁹ The \$2.060 billion does not reflect the FAM cost reduction associated with the Federal Loan Guarantee, which reduced FAM costs by \$485.9 million in December 2024.

¹³⁰ NSPI 2024 Annual FAM Report, A-3. Solid fuel includes coal and petcoke. Oils include diesel, bunker C, and furnace oil.

Figure IV-2: Percentages of Total Fuel Expense among Four Major Categories of NSPI's Fuel (2025)¹³¹



In this chapter, we review and assess NSPI's procurement of solid fuel. We do not include biomass in this chapter, instead reviewing biomass procurement and contract administration in a standalone chapter (Chapter VI). We begin by explaining NSPI's solid fuel-fired fleet, including which type of solid fuel each uses. Next, we look at NSPI's consumption of solid fuel during the Audit Period—that is, the amount of solid fuel burned for the purpose of generating electricity. We look at these data by plant, across solid fuel types, and in comparison with forecasts. We then explain the sources and types of NSPI's solid fuel. Next, we discuss the prices NSPI paid for solid fuel during the Audit Period. We then summarize NSPI's master supply contracts for solid fuel and all existing NSPI supply arrangements entering the Audit Period. We then review new supply arrangements for solid fuel executed during the Audit Period. Next, we provide our assessment of NSPI's solid fuel procurement process. We then review all contract actions taken by NSPI during the Audit Period (e.g., amendments, litigation, force majeure). We conclude with an assessment of NSPI's procurement of solid fuel-related goods and services, such as marine and rail transportation, as well as calcium chloride and powder activated carbon.

¹³¹ NSPI 2025 Annual FAM Report, A-3. Solid fuel includes coal and petcoke. Oils include diesel, bunker C, and furnace oil.

IV.B. Findings

IV.B.1. NSPI's Solid Fuel-Fired Fleet

Eight of NSPI's generating units—representing 1,229 MW of capacity—burn solid fuel as their primary fuel. Most are fired by coal; only Point Aconi (petcoke) burns something other than coal as primary solid fuel. **Figure IV-3** shows NSPI's solid fuel-fired fleet.

Figure IV-3: NSPI's Solid Fuel-Fired Fleet¹³²

Generating Unit	Max Net Capacity (MW)	Primary Solid Fuel	Other Solid Fuels
Lingan 1	153	Coal	Petcoke
Lingan 2	148	Coal	Petcoke
Lingan 3	153	Coal	Petcoke
Lingan 4	153	Coal	Petcoke
Point Aconi	168	Petcoke	Coal
Point Tupper	150	Coal	Petcoke
Trenton 5	150	Coal	Petcoke
Trenton 6	154	Coal	Petcoke
Total	1,229		

IV.B.2. Solid Fuel Consumption

NSPI consumed a total of [REDACTED] metric tonnes of solid fuel in the Audit Period. This was about 26.9% above forecasted consumption of [REDACTED] metric tonnes. Figure IV-4 provides these data in more detail, as broken down between 2024 and 2025.

Figure IV-4: NSPI's Solid Fuel Consumption vs. Forecast (2024, 2025)¹³³

Solid Fuel Type	2024			2025		
	Consumption (MT)	Forecast (MT)	Comparison	Consumption (MT)	Forecast (MT)	Comparison
Solid Fuel	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

There were a few key factors driving solid fuel consumption during the Audit Period. First, while NSPI received NS Block volumes that were in line with contractual obligations under the Energy and Capacity Agreement (when considering Make-up Energy), NSPI did not receive volumes of Surplus Energy under the Energy Access Agreement that were in line with forecasts. Total non-NS Block imported power over the Audit Period was 2.31 TWh, which was 1.47 TWh below forecasted imports of 3.79 TWh.¹³⁴ Additional coal-fired generation helped make up the missing 1.47 TWh. Second, as

¹³² NSPI 2025 Annual FAM Report, A-2.

¹³³ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).

¹³⁴ Q4 2024 FAM Report, 2(3); Q4 2025 FAM Report, 2(3).

explained later in this chapter, NSPI changed the fuel blends at several solid fuel-fired power plants to reduce sulfur emissions in 2024. This was due to NSPI's sulfur emissions compliance requirements, which limited the fleet to 68 kt of SO₂ emissions in the 2023-2024 period; NSPI emitted 36.4 kt in 2023, leaving just 31.6 kt of emissions in 2024. NSPI took steps to reduce sulfur emissions, including blending lower sulfur fuels at its solid fuel-fired plants, which consequently reduced the heat content of its fuel blends (thereby requiring more tonnes of coal to produce electricity). Third, on March 25, 2025, NSPI received a certificate of variance ("CoV") for sulfur emissions compliance for the 2025-2034 period. For 2025, the CoV increased the allowable SO₂ emissions from 28 kt to 45 kt. This allowed NSPI to rely more heavily on solid fuel in 2025, including lower cost mid-sulfur coal, driving higher consumption. Fourth, under the OBPS regime in place during the Audit Period, solid fuel-fired generation enjoyed a cost advantage relative to natural gas-fired generation. OBPS adders for Tufts Cove ranged between \$[REDACTED]/MWh and \$[REDACTED]/MWh during the Audit Period; solid fuel-fired generator OBPS adders were no more than \$[REDACTED]/MWh and in some cases, were actually negative, reaching as low as a *credit* of \$[REDACTED]/MWh. Differences in the OBPS adders made solid fuel-fired generation more economically attractive, leading to greater output and coal consumption.

Figure IV-5 shows NSPI's monthly consumption (blue line) against its forecasted consumption (green line). The figure shows that that NSPI consumed more solid fuel than forecasted in 20 out of 24 months.

Figure IV-5: NSPI's Month-by-Month Solid Fuel Consumption vs. Forecast (Metric Tonnes)¹³⁵



¹³⁵ Q1 2024 FAM Report through Q4 2025 FAM Report, inclusive, 3, 3(2), and 3(3).

Consumption during the Audit Period (3,382,115 metric tonnes) increased by 5.0 percent relative to the prior period (3,219,812 metric tonnes) but remains considerably below historical consumption. For example, consumption in the Audit Period was down 27.9 percent compared to the 2016-2017 audit period.¹³⁶

Figure IV-6 below shows annual total solid fuel consumption since 2016 and illustrates the reduction in consumption observed over that period.

Figure IV-6: NSPI's Annual Consumption of Solid Fuel since 2016 (Metric Tonnes)¹³⁷



IV.B.3. Solid Fuel Sources and Types

Several of NSPI's thermal generators burn blends of solid fuel, including various types of coal and petcoke. (We explain below NSPI's approach to blending fuels and the relative benefits of each type of solid fuel.) Traditionally, coal comes from a combination of domestic sources, such as the Stellarton Mine or the [REDACTED] Mine, or can be imported from the United States or South America. Petcoke is imported from the United States.

¹³⁶ 2022-2023 Bates White Audit Report, p.66.

¹³⁷ 2022-2023 Bates White Audit Report, p.66; Q1 2024 FAM Report through Q4 2025 FAM Report, inclusive, 3, 3(2), and 3(3).

During the Audit Period, almost all of NSPI's solid fuel was imported. Figure IV-7 shows, by month, NSPI's solid fuel consumption of petcoke, imported coal, and domestic coal. Imported coal represents the substantial majority of solid fuel consumption. Over the two-year Audit Period, NSPI's solid fuel mix was [REDACTED] imported coal, [REDACTED] % domestic coal, and [REDACTED] petcoke.¹³⁸

Figure IV-7: NSPI's Monthly Solid Fuel Consumption (Metric Tonnes) (by general solid fuel type)¹³⁹



Figure IV-7 shows the seasonality of NSPI's solid fuel consumption, with increased solid fuel consumption during the winter months. One way to illustrate the seasonality of NSPI's solid fuel consumption is to compare the lowest and highest consumption months of the Audit Period. For example, NSPI burned just 44,869 MTs of combined coal and petcoke in June 2024, while in January 2025, NSPI burned 243,153 MT, more than five times the consumption in the lowest month.

Coal types can vary in important ways, such as heat content (or, Btu content), which determines the efficiency of the coal, and byproduct content, such as certain emissions (e.g., SO₂) and solid waste (i.e., ash). Lower sulphur coal helps NSPI meet its emissions limitations, such as its SO₂ and mercury limits. Btu content determines the energy potential of the coal; the higher the Btu content, the more efficient that coal will be in generating electricity. Ash content is a measure of how much ash is produced by burning

¹³⁸ Data taken from NSPI's Quarterly FAM Reports, 4, 4(2), and 4(3); percentages do not sum to 100% due to rounding.

¹³⁹ Q1 2024 FAM Report through Q4 2025 FAM Report, inclusive, 4, 4(2), and 4(3).

the coal; higher ash content coal is more challenging to manage than low-ash coal. Each plant has a “staple fuel” that is the core fuel primarily used at a given unit to support reliable operation; each plant also uses “adders,” which are generally inferior fuels blended in with the staple fuels to reduce the overall cost of fuel for FAM customers. During the Audit Period, NSPI consumed the following types of coal:

- Low-sulphur, high Btu Colombian coal (import)¹⁴⁰—Sourced in northeastern Colombia and delivered by marine vessel, this coal helps NSPI meet its emissions limitations due to its low sulphur content.
- Low-sulphur, low Btu Colombian coal (import)¹⁴¹—This coal is similar to the low-sulphur coal above but has a lower Btu content—and thus commands a lower price.
- Mid-sulphur US Northern Appalachian coal (import)¹⁴²—This coal is shipped by marine vessel from the United States and is typically lower cost than the LSL and LSH coals. It is sourced in the Northern Appalachian region, which includes portions of Pennsylvania, Ohio, Maryland, and West Virginia.
- [REDACTED] Mine coal (domestic)¹⁴³—The [REDACTED] Mine is an undersea mine on the eastern coast of Cape Breton. NSPI burned [REDACTED] coal primarily at the Lingan plant, which is about 30 kilometers from the [REDACTED] Mine. [REDACTED] coal was also burned for a brief period at Point Aconi. The [REDACTED] Mine ceased operations during the prior period and no new [REDACTED] coal was purchased by NSPI in this Audit Period. Only remaining inventories were burned (and fully consumed) by the end of the Audit Period.
- Petcoke (import)¹⁴⁴—Petroleum coke, or “petcoke,” was burned only at Point Aconi during the Audit Period, though has been part of most generator’s blends in prior periods. A byproduct of oil refining operations, petcoke is sourced from refineries in the United States, either in the Great Lakes region or the Gulf Coast. Petcoke typically has a higher sulphur content than coals, as well as a higher Btu content—overall, petcoke typically costs less than coal. Petcoke is burned in high amounts at Point Aconi, which has fluidized bed technology designed to burn petcoke as its

¹⁴⁰ This coal typically has a Btu/lb content of greater than 11,600, a sulphur content of less than 1%, and a mercury content of less than 0.08 ppm.

¹⁴¹ This coal typically has a Btu/lb content between 10,800 and 11,300, a sulphur content of less than 1%; and a mercury content of less than 0.08 ppm.

¹⁴² This coal typically has a Btu/lb content of about 12,900, a sulphur content of 3%, and a mercury content between 0.08 and 0.16 ppm.

¹⁴³ This coal typically has a Btu/lb content of about 13,700, a sulphur content of about 2.3%, and a contractual mercury content of about 0.12 ppm (though, as we explain in Chapter V, actual mercury content of Donkin coal was higher in sampled deliveries).

¹⁴⁴ NSPI’s petcoke typically has a Btu/lb content of about 14,000, a sulphur content of about 6%, and a mercury content between 0.01 and 0.02 ppm.

primary fuel; other thermal plants, including Lingan, Trenton 6, and Point Tupper, can burn petcoke to enhance the Btu content and to improve particulate emission control performance by increasing sulphur and lowering the ash content of the overall fuel blend.

Prior to this Audit Period, NSPI also consumed coal from another domestic source, the surface mine in Stellarton.¹⁴⁵ The Stellarton coal was consumed only unit at nearby Trenton 6, which was designed to burn high ash content coal. As we explained in our prior audit report, the Stellarton mine exhausted its supply and was closed down.¹⁴⁶ No Stellarton coal was consumed during this Audit Period.

Figure IV-8 shows the total amount of each type of solid fuels used by NSPI across the entire fleet on an MMBtu basis. Note that Colombian low-sulphur, high Btu (LSH) coal is the staple fuel at each of the Lingan units, and LS coal is the staple fuel at Point Tupper and Trenton 5. Petcoke is an adder fuel at all plants except Trenton 5, where it is not burned at all, and Point Aconi, for which it is a staple fuel.

Figure IV-8: NSPI's Coal, Petcoke Consumption by Plant (in MMBtu)

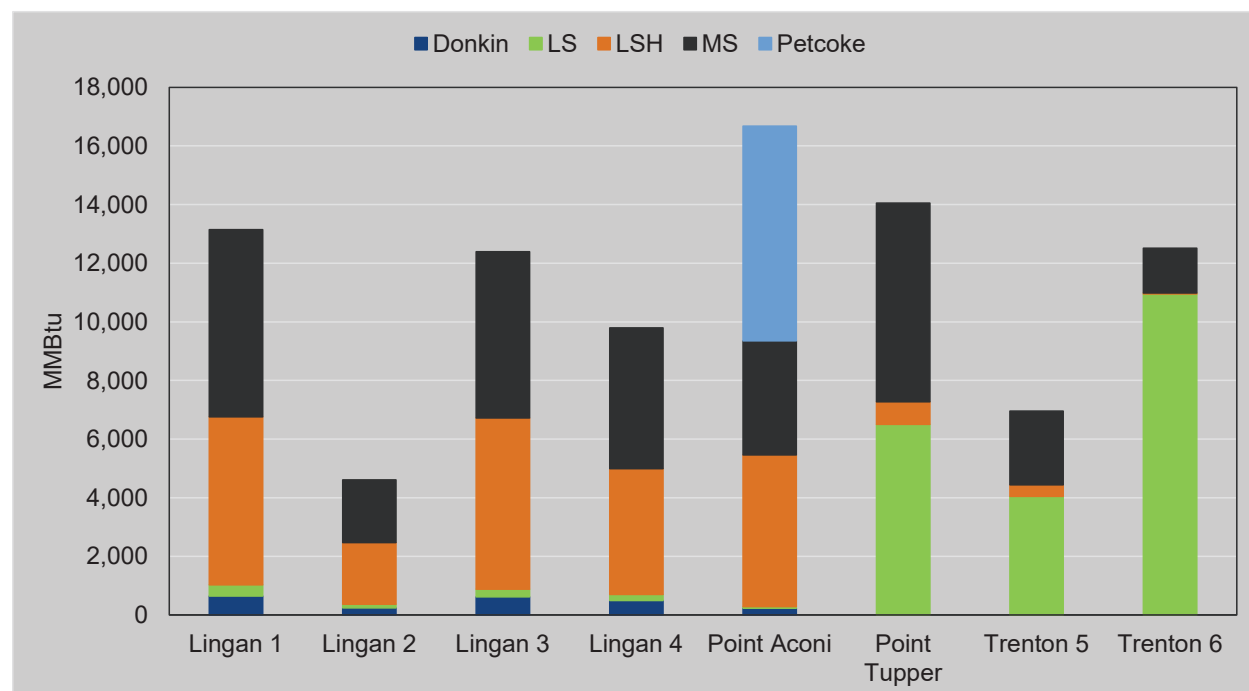
Plant		LS	LSH	MS	Petcoke
Lingan 1					
Lingan 2					
Lingan 3					
Lingan 4					
Point Aconi					
Point Tupper					
Trenton 5					
Trenton 6					
Total					

Figure IV-9 provides a graphical look at solid fuel use in MMBtu at each unit for the Audit Period. The figure also shows the overall consumption of solid fuel at each plant to provide perspective on the relative consumption at each plant.

¹⁴⁵ This coal typically has a Btu/lb content of about 10,600, a sulphur content of about 1.6%, and a mercury content of about 0.07 ppm.

¹⁴⁶ 2022-2023 Bates White Audit Report, section IV.B.3.

Figure IV-9: NSPI's Solid Fuel Consumption by Plant, Source (2024-2025, MMBtu)



The figures above provide useful insights into how the solid fuel fleet was operated during the Audit Period. First, consumption of [REDACTED] coal imports increased, making up 52.0 percent of all solid fuel consumed. In the prior audit period, that total was just 30.4 percent.¹⁴⁷ LSH consumption (27.0 percent) was particularly higher (vs. 14.8 percent in the prior audit period), though LSL consumption (25.0 percent vs. 15.6 percent in the prior audit period) was also materially higher. Second, domestic fuel contributions fell from 9.1 percent of all solid fuel in the prior audit period¹⁴⁸ to just 2.5 percent in this Audit Period. This was driven by closure of the Stellarton Mine and the cessation of operations at the [REDACTED] Mine, which were still contributing incremental supply in the prior audit period. Third, petcoke consumption at Point Aconi was reduced from 75.9 percent of the blend in the prior audit period¹⁴⁹ to just 43.9 percent in this Audit Period. NSPI reduced petcoke in Point Aconi's fuel blend for much of the Audit Period to lower SO₂ emissions, working with blends mostly between 40 and 50 percent petcoke but as low as 10 percent. Only at the end of the Audit Period (during December 2025) and after receipt of the CoV did NSPI again use 80 percent petcoke in Point Aconi's blend. Fourth, NSPI changed the fuel blend at Lingan and Trenton units to reduce SO₂ emissions, but did so in differing ways due to differences in those plants. Specifically, at Trenton, NSPI greatly increased the percentage of LSL coal in this mix—reaching as high as 100 percent LSL at Trenton 5 and 6 for a period of time—but limited LSL consumption

¹⁴⁷ 2022-2023 Bates White Audit Report, Figure IV-8.

¹⁴⁸ 2022-2023 Bates White Audit Report, Figure IV-8.

¹⁴⁹ 2022-2023 Bates White Audit Report, Figure IV-8.

at Lingan due to the threat of opacity violations¹⁵⁰ and derates. The Lingan units are subject to higher opacity risk than Trenton, particularly when burning LSL coal. During the Audit Period, the Lingan units experienced [REDACTED] total opacity exceedances; there were zero exceedances at Trenton. To lower sulfur content of the Lingan blends, NSPI removed petcoke from Lingan's blend and increased use of MS coal.

IV.B.4. Solid Fuel Prices

Following a volatile period of market pricing in the prior audit period,¹⁵¹ coal prices moderated and enjoyed reduced volatility during the 2024-2025 period. The [REDACTED], which is the index against which many of NSPI's coal contracts settle, ranged between just under \$[REDACTED]/tonne and just under \$[REDACTED]/tonne (USD) during the Audit Period.¹⁵²

NSPI reports its monthly coal and solid fuel costs-per-tonne consumed, which considers the cost of fuel already purchased and thus may not always be reflective of current market prices. Moreover, NSPI's hedging activities are intended to insulate ratepayers from volatile commodity prices. This hedging can come in the form of fixed price contracts or through use of financial hedging instruments tied to the [REDACTED] index that effectively lock in a fixed price for NSPI's indexed-priced coal contracts.

In this Audit Period, NSPI's solid fuel \$/tonne price forecast was [REDACTED] actual prices in all 24 months and exhibited a correlation of about [REDACTED] with actual observed prices.¹⁵³ Figure IV-10 provides a month-by-month look at NSPI's solid fuel prices—forecasted versus actual—for the Audit Period.

¹⁵⁰ Opacity limits apply to the Lingan, Point Aconi, Point Tupper, Biomass, Trenton, Tufts Cove, Burnside, Victoria Junction, and Tusket generating plants. For the solid fuel-fired resources and Tufts Cove, units are required to ensure opacity is maintained at or below 20 percent except visible emissions may increase in opacity to 40 percent for a maximum of six minutes in the sixty minutes following any increase in opacity above 20 percent. The generating unit is allowed to have the visible emissions increase between 20 percent and 40 percent for a maximum of two six-minute block average within an hour. Exceptions exist for startup, shutdown, and maintenance of units.

¹⁵¹ 2022-2023 Bates White Audit Report, section VI.B.4.

¹⁵² See, e.g., Coal (API2) CIF ARA (ARGUS-McCloskey) Continuous Contract, available at: <https://www.marketwatch.com/investing/future/mtfc00/charts>.

¹⁵³ Compiled from NSPI's Quarterly Reports, 3, 3(2), 3(3).

Figure IV-10: Solid Fuel Prices (\$/Tonne) (Forecasted vs. Actual, by month)¹⁵⁴



Looking more granularly at solid fuel prices, Figure IV-11 compares the month-by-month actual prices of imported coal, domestic coal, and petcoke, including shipping costs. Imported coal costs are impacted by the cost of shipping it from its sources in Colombia and the United States. Imported coal averaged \$[REDACTED]/tonne during the Audit Period, which was down approximately [REDACTED] percent compared to the prior audit period. Petcoke had an average price of \$[REDACTED]/tonne, which also represented a [REDACTED] relative to the prior audit period [REDACTED] percent). The small amount of domestic coal consumed averaged \$[REDACTED]/tonne during the Audit Period, a considerable increase from the prior period of [REDACTED] percent. However, this result was largely caused by the lack of consumption of any Stellarton coal in the current Audit Period, which is considerably less expensive on a per-tonne basis than [REDACTED] coal. NSPI consumed material amounts of Stellarton coal in the prior audit period. Detailed price data is shown in the figure below.

¹⁵⁴ Q1 2024 FAM Report through Q4 2025 FAM Report, inclusive, 3, 3(2), and 3(3).

Figure IV-11: Imported Coal, Domestic Coal, and Petcoke Prices (\$/Tonne)¹⁵⁵



Figure IV-12 provides a breakdown across the two-year Audit Period of the solid fuel costs-per-tonne consumed, which again considers the cost of fuel already purchased and thus may not always be reflective of current market prices. The figure shows that on average, dollar-per-tonne solid fuel prices decreased by approximately 15% across the fleet in 2025 relative to 2024 prices.

Figure IV-12: Solid Fuel Prices by Plant, excluding additives (\$/Tonne)¹⁵⁶

Plant	2024	2025
Lingan		
Point Aconi		
Trenton 5		
Trenton 6		
Point Tupper		

Factoring in the additional cost of environmental additives (limestone, powder activated carbon, and calcium chloride) increases the cost of operations at each of the solid-fuel fired power plants and has some impact on the relative costs of the solid fuel-fired units, as can be seen in Figure IV-13. Point Aconi

¹⁵⁵ Q1 2024 FAM Report through Q4 2025 FAM Report, inclusive, 3, 3(2), and 3(3). The missing data points for domestic coal and pet coke indicate months in which there was zero recorded consumption of either product, respectively.

¹⁵⁶ Q4 2024 FAM Report, 12(3), 15(3), 17(3), 19(3), 22(3); Q4 2025 FAM Report, 12(3), 15(3), 17(3), 19(3), 22(3); the figure's data is calculated using tonnes of coal and petcoke (as applicable) only and not the tonnage of the environmental adders.

(increase of 5.8%) is most heavily impacted by the cost of environmental adders. Most others are 4-5 percent impacted.

Figure IV-13: Solid Fuel Prices by Plant, including additives (\$/Tonne)¹⁵⁷

Plant	2024	2025	Average Increase in \$/Tonne Attributed to Additives
Lingan			4.5%
Point Aconi			5.8%
Trenton 5			4.2%
Trenton 6			2.5%
Point Tupper			4.6%

As already noted, the data above looks only at the cost of solid fuel consumed—an accounting, backward looking measure that includes hedging impacts and that does not always reflect changes in market conditions. Thus, as a further review of NSPI's solid fuel costs, we compiled the daily fuel cost for each solid fuel-fired unit that was used by NSPI in committing and dispatching the system. Unlike the data above, the fuel costs used in dispatching the system are meant to capture the replacement cost of the fuel being burned and thus should reflect the changes in market prices for solid fuel.

The figure below shows the \$/MMBtu cost of the solid fuel component of the total cost used in dispatching the units. The figure does not include the cost of environmental adders or other dispatch price adjustments (e.g., OBPS costs) that impacts the marginal cost of each unit. Here, we focus only on the solid fuel component cost to illustrate how solid fuel costs translated to dispatch costs. The figure shows that overall solid fuel prices used in dispatch fell during this Audit Period with broader market conditions. Point Aconi's higher use of petcoke led its fuel component to be lowest, though marginal cost adders drive its full marginal cost higher. Two outlying periods of data are the steep increase in the fuel component cost for Trenton 5 and Trenton 6 over the November 20, 2024 to January 2, 2025 period. NSPI explained that due to low inventory at Trenton and challenges in maintaining inventories as consumption ramped up at both units into the winter season, NSPI adjusted the marginal costs of both Trenton 5 and Trenton 6 to be based on the marginal cost of HFO instead of solid fuel. This resulted in the marginal costs of these two units doubling during this period.

¹⁵⁷ Q4 2024 FAM Report, 12(3), 15(3), 17(3), 19(3), 22(3); Q4 2025 FAM Report, 12(3), 15(3), 17(3), 19(3), 22(3).

Figure IV-14: Monthly Fuel Prices Used in Dispatch by Plant (\$/MMBtu)



IV.B.5. NSPI's Solid Fuel Procurement Process Assessment

NSPI's solid fuel procurement processes are clearly laid out in NSPI's Fuel Manual¹⁵⁸ are designed to use competition to benefit FAM customers. The process allows NSPI to leverage its position as a buyer for multiple solid fuel-fired generators to achieve better results. This is because NSPI has the flexibility to ship its solid fuel to multiple ports and to burn much of its imported solid fuel at multiple units.

NSPI's process includes clear guidelines and targets for its solid fuel portfolio, such as striving to have at least ■■■ suppliers, with no one supplier providing more than ■■■% of its annual needs.¹⁵⁹ In addition, NSPI seeks to limit exposure to a single country's solid fuel supply to no more than ■■■% of its needs, and not committing to any one single mine more than ■■■% if international or ■■■% if domestic of its purchases.¹⁶⁰ We observed no violations of these guidelines during the Audit Period, though do explain one instance in section IV.B.7.d below of an NSPI LSH purchase that caused exceedances of ■■■■ stated risk exposure limits.

NSPI's RFP process for coal and petcoke is well designed and encourages healthy participation by suppliers. Evidence of the success of the RFP process can be measured by participation throughout the

¹⁵⁸ Fuel Manual Revision 14, Link 6.

¹⁵⁹ Fuel Manual Revision 14, Link 6, page 5.

¹⁶⁰ Fuel Manual Revision 14, Link 6, page 5.

Audit Period, which saw several suppliers offering multiple RFPs, and several winning suppliers. Importantly, too, NSPI negotiated with winning suppliers in good faith, meaning that NSPI honored the conditions of each winning bid, while still holding bidders to their promises in those bids. The RFP evaluation methodology is also reasonable, as it focuses on price, and takes into account transportation costs, quality adjustments, and environmental adjustments and limitations. The RFPs also consider counterparty risk, such as credit and country risk.

Another important process is NSPI's recordation of procurement approval by the FST, which is typically well documented and contained in the Fuels Data Cart. These "Record of Procurement Approval" documents are issued for all solid fuel procurements—not just those related to RFPs. These documents ensure that purchases are vetted by management and are sufficiently justified, including showing the need for the purchase, the reasons for transacting with the counterparty, and the evaluation modeling done by ERM to assess the transaction.

In practice, we found NSPI's procurement processes to be effective. While NSPI is not required by the Fuel Manual to exclusively rely on RFPs for solid fuel supply, we found evidence that the RFP was NSPI's favored approach. In almost every case, NSPI selected the lowest priced offer, when adjusted for quality and environmental attributes.

IV.B.6. NSPI's Suppliers of Solid Fuel

In this section, we address NSPI's suppliers of solid fuel, including coal and petcoke. Later, we discuss NSPI's procurement of other products and services associated with the solid fuel generating units that are FAM expenses, including additives and transportation services.

During the Audit Period, NSPI contracted with [REDACTED] suppliers for imported coal, [REDACTED] [REDACTED].¹⁶¹ The contracts for the provision of solid fuel supply deliveries were signed as far back as March 2022, while others were executed (and/or amended) during the Audit Period. In some cases, such as with [REDACTED] and [REDACTED] NSPI had in place a "master" supply agreement already in place for solid fuel and during the Audit Period. These master agreements—similar in scope to International Swaps and Derivatives ("ISDA") or North American Energy Standards Board ("NAESB") agreements for natural gas, power, or hedging transactions—help reduce the time and cost of buying solid fuel by codifying a set of agreed-upon terms and conditions of supply that does not change or require renegotiation for each solid fuel shipment. These master agreements tend to be long-term agreements¹⁶² that specify the terms by which the buying and selling parties will transact, including the

¹⁶² Typically, the master agreements do not specify a termination date; rather, the contract allows either party to terminate the contract under certain conditions.

quality specifications and references to the applicable American Society for Testing and Materials (“ASTM”) standards. The agreements also specify how the fuel will be weighed and tested and how the price will be adjusted if weight and/or quality do not meet specifications. Over the life of that master agreement, the parties will enter into shorter-term agreements, called “confirmations,” which specify the amount of solid fuel that NSPI will buy over that period, the price, the quality, the period in which NSPI can specify delivery, and various other information that is specific to that short-term agreement.

For other suppliers, such as [REDACTED] the agreements include specified terms and include delivery quantities, prices, and schedules. Figure IV-15 summarizes NSPI’s suppliers of solid fuel during the Audit Period. Note that as of January 14, 2025, two long-time solid fuel providers [REDACTED] [REDACTED] combined in a merger of equals to produce a new supplier, [REDACTED]¹⁶³ Both [REDACTED] were suppliers to NSPI during the Audit Period. We report these suppliers as one entity in the figure below.

Figure IV-15: NSPI Solid Fuel Suppliers During Audit Period

Supplier	Product
[REDACTED]	

The figures below provide more detail on NSPI’s solid fuel portfolio status. Figure IV-16 shows NSPI’s physical supply portfolio—including all suppliers—as of December 31, 2024. Figure IV-17 provides this data as of December 31, 2025, the last day of the Audit Period.

¹⁶³ [REDACTED]

Figure IV-16: NSPI Physical Solid Fuel Portfolio Supply Status (as of December 31, 2024)



Figure IV-17: NSPI Physical Solid Fuel Portfolio Supply Status (as of December 31, 2025)



IV.B.7. New Supply Agreements during the Audit Period, by Quarter

During the Audit Period, NSPI entered into new contracts for solid fuel supply. We reviewed each of these contracts and the process by which those contracts were executed—this includes how winning suppliers were selected and why NSPI sought additional supply. We also discussed several of these procurements and NSPI’s associated decision-making with NSPI. Below, we provide a summary of all new contracts signed over the two-year Audit Period, by quarter. We include both a table for each quarter showing the new contracts signed and a short summary of the contracts themselves.

IV.B.7.a. First Quarter 2024

NSPI entered into no new contracts for solid fuel supply in the first quarter of 2024.

IV.B.7.b. Second Quarter 2024

NSPI entered into no new contracts for solid fuel supply in the second quarter of 2024.

IV.B.7.c. Third Quarter 2024

NSPI entered into [REDACTED] new contracts for solid fuel supply in the third quarter of 2024. These are shown in Figure IV-18.

Figure IV-18: NSPI New Solid Fuel Supply Contracts (Q3 2024)¹⁶⁴

Supplier	Product	Quantity (MT)	Term
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Mid-Sulfur purchases [REDACTED] On May 27, 2024, NSPI issued an RFP for mid-sulfur coal, inviting over a dozen parties to submit an offer. The RFP sought between 100,000 and 400,000 tonnes/year for 2024, 2025, and 2026, with delivery to the International Pier and Point Tupper Marine Terminal. To assist with sulfur compliance, the RFP sought mid-sulfur coal with lower sulfur content than is typical, specifying no more than 2.5% sulfur. [REDACTED] parties submitted a combined [REDACTED] total offers:

[REDACTED] Of the [REDACTED] offers received, [REDACTED] were eliminated due to the type and quality of coal, which NSPI deemed to be at risk of causing derates in the fleet. These included [REDACTED]

[REDACTED] Opacity issues can arise if overall sulfur blends are low; NSPI explained that its coal-fired generators are designed to operate on mid-sulfur coal, with the sulfur oxides interacting with the electrostatic precipitators¹⁶⁵ to facilitate effective fly ash capture and reduce the opacity of the flue gas, or gas being released to the air. Lower sulfur content can therefore cause opacity issues. Each of these supply offers were disqualified based on recommendations by NSPI's subject matter experts.

The remaining [REDACTED] offers were evaluated on a delivered basis, accounting for environmental and quality attributes of the coal supply. [REDACTED] offer had the lowest evaluated price, followed by [REDACTED] NSPI selected both offers, which would supply coal in 2024 and 2025. For 2024, NSPI had a forecasted

¹⁶⁴ NSPI Q3 2025 FAM Report, Q3.

¹⁶⁵ Electrostatic precipitators remove fine particles from a stream of gas by using electrical energy to charge particles and attract those particles to collector plates carrying the opposite charge.

open position of [REDACTED] tonnes of coal. The [REDACTED] volumes largely filled that need at a combined quantity of [REDACTED] tonnes of coal. The ROA associated with this RFP noted that NSPI was also forecasted to receive [REDACTED] tonnes of [REDACTED] coal in 2024, which counts towards its mid-sulfur requirements. NSPI noted that the volumes of coal from [REDACTED] could result in surplus inventories if the [REDACTED] supply was actually provided in 2024 but noted that “[REDACTED] [REDACTED] at the [REDACTED] [REDACTED]. To mitigate the risk of excess inventories of mid-sulfur coal, NSPI also limited its purchases in 2025 to [REDACTED] tonnes, which was less than its forecasted open position of [REDACTED] tonnes for 2025. Finally, NSPI chose not to pursue any 2026 supply from the offers received, noting that only [REDACTED] parties ([REDACTED]) offered viable coal supply in 2026, which limited competition. The purchases associated with this RFP were fixed price purchases, which therefore required (and received) CROC approval.

In our view, NSPI’s decision-making regarding this RFP was sound. We confirmed that contracts with [REDACTED] matched the RFP offers as evaluated. The total estimated value of the contracts was \$ [REDACTED] million USD. Moreover, it should be noted that the [REDACTED] supply never did materialize (in 2024 or later). [REDACTED], with NSPI having no knowledge of any plans related to its future. NSPI was subject to a contract with [REDACTED] the operator of the [REDACTED], for [REDACTED] coal, but only to the extent that any coal was mined during the contract period.¹⁶⁶ That contract expired at the end of 2024 and there was no further mined coal from [REDACTED] or deliveries of [REDACTED] coal to NSPI. As of the end of the Audit Period, NSPI has no outstanding or unresolved contractual obligations related to the [REDACTED].

LSH Purchases from IMI Fuels, [REDACTED] for 2024, 2025: On June 10, 2024, NSPI issued an RFP for LSH coal, seeking 100,000-200,000 tonnes of supply per year for 2024, 2025, and 2026. NSPI forecasted an open position of [REDACTED] in 2024 and [REDACTED] in 2025, plus [REDACTED] open position in 2026. The RFP was issued in anticipation of an upcoming NSPI-option to purchase three additional cargoes from [REDACTED] under an existing agreement; NSPI was required to exercise that option by July 1, 2024. The RFP, therefore, allowed NSPI to test the economics of its option with [REDACTED] against firm, binding offers from other suppliers.

The RFP received [REDACTED] supply offers for 2024 supply, including an offer from [REDACTED]. NSPI also received [REDACTED] offers for 2025 supply and [REDACTED] for 2026 supply. NSPI rejected [REDACTED] offers for operational reasons: [REDACTED]
[REDACTED]
[REDACTED] leading NSPI’s subject matter experts to not pursue this type of coal.
[REDACTED] compared to other offers ([REDACTED]), which would limit NSPI’s ability to achieve sulfur compliance targets, which were tight and challenging in 2024.

¹⁶⁶ [REDACTED] ([REDACTED])

That left [REDACTED] offers, plus the [REDACTED]. The most economic of these offers for 2024 supply was [REDACTED] fixed price Colombian supply, which NSPI selected for two cargoes in 2024. The next most economic option was NSPI's option with [REDACTED], which evaluated at a lower all-in price than the RFP offers of [REDACTED]. One of these cargoes would be scheduled for 2024, bringing the total procured in the RFP to [REDACTED] tonnes, the total forecasted need. Two of the IMI Fuels cargoes would be scheduled for 2025 and would meet the total forecasted need of [REDACTED] tonnes. Though offers were received for 2026 supply, just [REDACTED] offered supply from a source recommended by NSPI's subject matter experts as suitable for consumption in the fleet. [REDACTED]

Total contract value for the [REDACTED] volumes was estimated to be \$ [REDACTED] while the [REDACTED] cargoes were expected to have a total value of [REDACTED]. [REDACTED] We confirmed that the [REDACTED] contract matched the supply offer as evaluated.¹⁶⁸ NSPI's decision-making regarding this RFP and the [REDACTED] optional cargoes was reasonable in our view.

IV.B.7.d. Fourth Quarter 2024

NSPI entered into [REDACTED] new contract for solid fuel supply in the fourth quarter of 2024. This is shown in Figure IV-19.

Figure IV-19: NSPI New Solid Fuel Supply Contracts (Q4 2024)¹⁶⁹

Supplier	Product	Quantity (MT)	Term
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

LSH Purchases from IMI Fuels for 2025, 2026: On October 3, 2024, NSPI issued an RFP for low-sulfur coal, seeking up to 400,000 tonnes of LSH supply per year for 2025 and 2026 and up to 200,000 tonnes of LSL per year for 2025 and 2026. NSPI forecasted 2025 LSH open positions of [REDACTED] tonnes for 2025 and [REDACTED] tonnes in 2026. NSPI also forecasted LSL open positions of [REDACTED] tonnes in 2025 and [REDACTED] tonnes in 2026.

The RFP received offers from [REDACTED] suppliers, with substantial numbers of offers for most products: 2025 LSH ([REDACTED] offers), 2026 LSH ([REDACTED] offers), 2025 LSL ([REDACTED] offers), and 2026 LSL ([REDACTED] offers). NSPI rejected several offers for operational reasons, including higher-than-allowable chlorine content and low iron oxide content. Following these rejections, NSPI was left [REDACTED] offers for 2025 LSH (and [REDACTED] for 2026), plus [REDACTED] offers for 2025 LSL and [REDACTED] offers for 2026 LSL. The remaining bids and their fully

¹⁶⁷ "IMI - 20240628 NS Power Formal Option Declaration - Trade Confirmation Dated October 20 2023."

¹⁶⁸ "Pac Basin - 20240828 [REDACTED]"

¹⁶⁹ NSPI Q4 2024 FAM Report, Q3.

evaluated prices (considering transportation, heat content, quality, and environmental attributes) are shown in the figure below. The sole selected offer () is highlighted.

Figure IV-20: October 2024 LSH, LSL Evaluated Bids (\$/MMBtu)

2025 Bids		
Supplier	Coal type	Evaluated Price (\$/MMBtu)
	LSL	\$7.41
	LSL	\$7.50
	LSH	\$7.88
	LSH	\$7.88
	LSH	\$7.96
	LSL	\$8.09
	LSL	\$8.12
	LSL	\$8.18
	LSL	\$8.19
	LSH	\$9.13
2026 Bids		
	LSL	\$7.50
	LSL	\$7.54
	LSL	\$8.18
	LSL	\$8.15
	LSL	\$9.41

For 2025 supply, NSPI selected a single () which had a fully-evaluated price of \$ /MMBtu. () was the lowest priced LSH offer. Regarding LSL, NSPI selected no offers, including the () that had lower fully-evaluated prices () selected LSH offer. NSPI noted:

Solid Fuels team is not recommending purchasing LSL supply at this time. The rationale being that the Q4 forecast has not been finalized, and there is a strong possibility that the current open position of 2 cargos for LSL coal, could be replaced by additional LSH requirements. Based on the analysis performed by NS Power operations, it is possible that LSL coal will not be pursued in 2025 and 2026, as LSH coal offers NS Power more flexibility in blending coal to maximize unit performance while achieving sulfur emission targets.

NSPI's evaluation process allows for direct comparisons of LSL with LSH offers, as it adjusts for coal quality, heat content, and environmental attributes, and does so on a fully-delivered basis (therefore accounting for transportation). As such, it is clear that the () were evaluated by NSPI as superior to the selected () offer. The cost of pursuing the () supply instead of the lowest priced offer from () which was based on the () was \$ /MMBtu, or an increase of () percent. Based on the value of the ()—estimated to be \$ million USD—NSPI spent an incremental \$ million USD to purchase the () supply, rather than the () LSL indexed-priced supply.

[REDACTED]

For 2026, NSPI selected no offers. NSPI received no 2026 offers to supply LSH that were recommended for consumption by NSPI's subject matter experts. NSPI received several valid LSL offers, but similar to its assessment of the 2025 LSL offers, [REDACTED]

[REDACTED] NSPI also noted that, in subsequent discussions, [REDACTED] on this point. (NSPI did so, and ultimately was able to make LSH coal available to NSPI in 2026.)

[REDACTED]

LSH and the lack of suitable LSH options available to NSPI outside of Colombia. NSPI also noted [REDACTED] strong performance as a supplier. CROC completed a thorough review of [REDACTED] and submitted a memo explaining the risks associated [REDACTED] the [REDACTED] and the Colombian region. The transaction was ultimately approved by the FST.

In our view, NSPI's decision to approve the transaction despite the risk exposure exceedances in the Fuel Manual was reasonable. The Solid Fuel Portfolio Process allows for NSPI to deviate from risk exposure guidelines: "Each solid fuel transaction proposed to the FST will reflect the changes in percentage commitment metrics for mine, country and supplier risk, and include rationale if the

procurement will result in deviation from the percent commitment guidelines.”¹⁷⁰ NSPI’s ROA contained the calculated percentage changes and the rationale for deviations. NSPI also noted that the exposure exceedances would be temporary, lasting only to the second or third quarter of 2025.

Still, the CROC memo on this subject is instructive and illustrates the risks of the transaction and NSPI’s coal purchasing more generally:

Cucuta is a principal crossing point from Venezuela into Colombia, the city has seen rising levels of violence as it struggles to confront the strength of Venezuelan criminal groups. Officials have reported rapidly increasing regional rates of kidnapping, extortion, armed robbery and murder, as much of the region is controlled by gangs.

Illegal armed groups have targeted and attacked coal mines in Cucuta, killing dozens of workers. As a result of attacks, four oil and copper companies announced plans to discontinue operations in the region. Colombia and Cucuta in particular has been frequently associated with allegations of corruption in the border region.

Moreover, [REDACTED] as an entity that is not rated by the major credit rating agencies, nor publishes financial statements, has limited publicly-available information on which to base a credit risk assessment. CROC noted that Standard & Poor’s (“S&P”) publishes an “Expanded Fundamental Probability of Default” for such companies, and gave [REDACTED] a 4.3 percent one-year probability of default and 16.2 percent three-year probability of default, which correspond to an implied S&P credit rating of “B.” A rating of “B” is a non-investment grade rating under S&P’s rubric. We conclude, therefore, that this transaction did subject NSPI to a material increase in risk, but that NSPI followed the dictates of its Fuel Manual and determined to exceed its stated risk thresholds based on a reasonable rationale.

Additional LSH Cargo in 2024: As noted in the discussion of the Third Quarter 2024 LSH procurement above, NSPI had closed out its forecasted low sulfur coal needs for 2024 by the end of the third quarter. However, upon running its fuel and purchased power forecast in August 2024, NSPI identified a need for an incremental LSH cargo (58,000 tonnes) for consumption at Langan. NSPI explained that “[t]his increase in coal consumption is tied to the extended LIL outage in August and September, and an unanticipated outage at New Brunswick’s Point Lepreau plant, which limited NS Power’s ability to import energy over the New Brunswick tie.”

NSPI did not issue an RFP to meet this need, but rather canvassed [REDACTED] Basin, its existing suppliers of LSH fuels at that time, given that these parties had offered viable supply for coal with sufficiently high heat content, unlike [REDACTED] [REDACTED] could not offer an incremental cargo, while [REDACTED] was able to offer a single cargo of 58,000 tonnes, delivered in 2024, at a fixed price of [REDACTED]. This was more favorable than [REDACTED] offer in the third quarter 2024

¹⁷⁰ Fuel Manual Revision 14, Link 6, page 6.

LSH RFP. The total cost of the cargo was estimated to be [REDACTED] We confirmed the contract matched the offer terms.¹⁷¹

We take no issue with NSPI's decision to pursue this cargo, nor its decision to forgo an RFP and directly canvass its two most viable suppliers, as determined by its experience in the June 2024 LSH RFP. NSPI appropriately reassessed its forecasted solid fuel consumption in a timely manner and in light of outages at the major external resources on which it relies for imported power—namely, the LIL (for Newfoundland imports) and Point Lepreau (for New Brunswick imports). Without the LIL, imports from Muskrat Falls fall to zero; without Point Lepreau online, imports from New Brunswick become much less available, since New Brunswick Power loses its largest source of generation. This incident only underscores NSPI's reliance on its neighbors, and if outages or other constraints occur in New Brunswick and/or Newfoundland and Labrador, NSPI may need to incur incremental costs or, at minimum, accelerate certain purchases and costs. Here, those costs came in the form of an incremental LSH cargo at a cost of almost \$7 million USD.

[REDACTED]

[REDACTED]

[REDACTED]

¹⁷¹ "IMI - 20240903 Product Sales Agreement."

IV.B.7.e. First Quarter 2025

NSPI entered into no new contracts for solid fuel supply in the first quarter of 2025.

IV.B.7.f. Second Quarter 2025

NSPI reported entering into three new contracts for solid fuel supply in the second quarter of 2025. This is shown in Figure IV-21.

Figure IV-21: NSPI New Solid Fuel Supply Contracts (Q2 2025)¹⁷²

Supplier	Product	Quantity (MT)	Term

LSL, LSH Purchases and Deferrals in Wake of CoV: On March 7, 2025, NSPI issued an RFP for LSH and LSL coal. NSPI sought up to 696,000 tonnes of supply (not distinguishing between LSL and LSH sub-targets) for delivery starting in the second half of 2025 through the end of 2026. Responses were due March 14, 2025. Following receipt of offers, however, NSPI received its SO₂ CoV on March 25, 2025, which had a dramatic impact on NSPI's optimal solid fuel procurement strategy. Annual allowable SO₂ emissions increased under the CoV from 28 kt to 45 kt in both 2025 and 2026. Generally, the CoV meant NSPI could consume more coal in 2025 and 2026 and could use more mid-sulfur coal in its blends, allowing for more consumption of LSL coal in such blends and less need for LSH's higher heat content.

¹⁷² NSPI Q3 2025 FAM Report, Q3.

The RFP [REDACTED] for 2025 LSH supply, [REDACTED] for 2026 LSH supply, [REDACTED] for 2025 LSL supply, and [REDACTED] 2026 LSL supply. Two sets of LSH offers were eliminated from further consideration due to operational concerns with the coal supply (removing two 2025 LSH bids and two 2026 LSH bids). One LSL offer (2025 supply only) was eliminated for similar reasons.

From the remaining bids, NSPI chose to not select any LSH bids for 2025. NSPI noted that the impact of the CoV was to no longer require LSH for 2025 to meet sulfur emissions requirements. Moreover, NSPI determined it optimal to negotiate with its existing LSH supplier ([REDACTED]) to defer two cargoes of 2025 LSH supply to 2026 (totaling 116,000 tonnes), where NSPI was still forecasting an open position of 174,000 tonnes of LSH. (NSPI successfully negotiated this deferral with [REDACTED].) NSPI would also later decline a contractual option to procure an additional LSH cargo from [REDACTED] in 2025 due to a lack of need for additional LSH in 2025.

Regarding LSL in 2025, NSPI forecasted a need of [REDACTED] (due to the deferral of the [REDACTED] LSH cargoes). To fill this need, NSPI selected the lowest cost LSL offer, [REDACTED] which was offered at the [REDACTED]

Before continuing our assessment of NSPI's procurement activities in the wake of receiving the CoV, we wish to make two points regarding the indexed pricing of [REDACTED]. First, the impact of deferring two fixed price cargoes of [REDACTED] LSH cargoes and adding two cargoes [REDACTED] priced at index had a material impact on NSPI's hedged position for 2025 coal price exposure. Specifically, pre-CoV, NSPI was 104 percent hedged; post-CoV, NSPI's solid fuel hedge percentage fell to 77 percent. NSPI did not add any additional [REDACTED] hedges to account for this change, as the overall portfolio remained in line with hedge targets and, as importantly, NSPI's hedged position related to low sulfur coal in particular (LSL and LSH coals) was actually overhedged at 114 percent. We took no issue, therefore, with NSPI's decision to not procure additional [REDACTED] hedges in light of the [REDACTED] indexed price cargoes' replacement of the fixed price [REDACTED] cargoes in 2025.

Second, NSPI's evaluation methodology treats indexed priced bids as given, using the current index futures price to evaluate such bids against fixed price alternatives. NSPI does not add a risk premium associated with index-priced bids. This is a reasonable approach, but NSPI could benefit from some additional consideration of how to quantify the risk or additional cost associated with index priced bids. Specifically, an index-priced bid is subject to change and could get more expensive if the index price rises. NSPI noted that it hedges its [REDACTED] index exposure through derivative contracts, which is a valid point and a credible way to reduce exposure to index price variations. However, hedging does have some costs and NSPI's hedge transactions are not executed on the same day as executed coal supply agreements with indexed pricing. Developing a hedge strategy and getting approval for executing new hedges—as well as the execution process itself—takes time, and thus subject such hedging to risk of material price movements in the index. We include a recommendation that NSPI consider a method to account for index price risk when evaluating index priced offers against fixed price alternatives.

For 2026, NSPI selected [REDACTED] for the provision of [REDACTED] tonnes of LSL, which would provide NSPI its full forecasted open position for the year. [REDACTED] offer was the lowest priced offer received, as determined on a fully-evaluated basis (including transportation, quality, and environmental characteristics). NSPI also selected [REDACTED]' offer for a single cargo of LSH coal to close out its 2026 open LSH position. [REDACTED] offer was the only offer received for 2026 LSH coal from a mine that was approved by NSPI's subject matter experts as suitable for consumption in the fleet. The total estimated cost of [REDACTED] was \$ [REDACTED]. We verified that this price matched the contract signed with [REDACTED].¹⁷³ The total cost of the single LSH cargo from [REDACTED] in 2026 was \$ [REDACTED]. We confirmed that the terms of the LSH offer matched the final contract amendment reached with [REDACTED].¹⁷⁴

NSPI's RFP activity and deferred LSH shipments were reasonable, as they responded to a substantial exogenous event (the CoV). NSPI was able to determine the impact of the CoV on its expected coal consumption, determine its new exposure, and to take steps to close out that exposure. NSPI used competition (through the RFP) and bilateral requests (to defer [REDACTED] deliveries) to make these purchases efficiently. We took no issue with NSPI's activities in the wake of the CoV related to LSL and LSH.

In addition to its LSL and LSH activities, NSPI also took action with regards to MS coal, which could now be used more liberally with the relief afforded by the CoV. Specifically, NSPI received an unsolicited offer from [REDACTED] for an available cargo of MS coal, which NSPI accepted. We address this purchase in the discussion of the April 2025 RFP for MS coal, next.

Post-CoV Mid-Sulfur Coal RFP, Purchases: On April 25, 2025, NSPI released a mid-sulfur coal RFP seeking up to 300,000 tonnes in the second half of 2025 and up to 700,000 tonnes in 2026. These targets were consistent with NSPI's forecasted open MS coal positions, which were 290,000 tonnes in 2025 and 638,000 tonnes in 2026.

[REDACTED] offered into the RFP, combining for eleven offers for 2025 supply [REDACTED] for 2026 supply. Again, NSPI's subject matter experts recommended against accepting supply from the mines of several of the offers due to concerns with chlorine, moisture, low heat content, and metallurgical coals, among other concerns, which were memorialized in an appendix to the ROA. Of the remaining offers, NSPI selected [REDACTED] to provide ten cargoes (five in 2025, five in 2026) and [REDACTED] to provide six cargoes (all in 2026). [REDACTED] offer had the lowest evaluated price for 2025 supply. For 2026, [REDACTED] offer had the lowest evaluated price and offered the full volume (696,000 tonnes). NSPI selected [REDACTED] for only six cargoes, however, totaling 348,000 tonnes, and selecting [REDACTED] to

¹⁷³ [REDACTED] - 20250416 THE SALE AND PURCHASE OF COAL.”

¹⁷⁴ “IMI - 20250422 First Amendment.”

provide the rest (five cargoes, or 290,000 tonnes). [REDACTED] had the second lowest price offer for 2026 coal, after [REDACTED] with a difference of \$ [REDACTED]

NSPI's decision-making regarding this RFP appears sound. The volumes procured were tied to its forecasted open positions for MS coal. NSPI's selection of [REDACTED] as the largest supplier in the RFP is logical given [REDACTED] offered the lowest evaluated price supply. The selection of [REDACTED] for just a portion of the 2026 MS coal supply is also reasonable, despite [REDACTED] offering a lower evaluated price than [REDACTED]. [REDACTED]'s offer in the RFP was for both 2025 and 2026 supply, and it was not clear from the offer that it was making these offerings *a la carte*. NSPI ultimately selected [REDACTED] tonnes of [REDACTED] supply in both 2025 and 2026, limiting the risk that [REDACTED] would not execute an agreement for 2025 supply only. More importantly, NSPI identified risk associated with becoming too reliant on [REDACTED] as a supplier. NSPI's ROA stated that the Energy and Risk Management team "recommends portfolio diversification to hedge the coal delivery risk with [REDACTED] by purchasing 6 cargoes from [REDACTED] and 5 cargoes from [REDACTED] in 2026." NSPI noted:

[REDACTED] is a commodity trader who does not own the underlying mine assets or the shipping port and is less flexible in logistical matters. [REDACTED] cannot influence physical operations of coal mines, coal production volume, and load port availability. [REDACTED] like any other customer, books the loading port and must load and deliver at scheduled times.

In addition to the counterparty risk, taking [REDACTED] of MS coal from [REDACTED] in 2026 would reduce NS Power's coal delivery scheduling flexibility and increase the risk of having either too much or not enough MS coal on the ground through 2026.

...

Having [REDACTED] Resources as an additional supplier in 2026, despite the slightly higher price, will assist with managing the solid fuel supply and energy production risk.

...

The [REDACTED] coal comes from two different mines, [REDACTED] and [REDACTED], which carries an inherent risk with coal chemistry consistency depending on the blend NS Power receives. NS Power is particularly concerned with Mercury content stability.

NS Power has not done a deal of this size with [REDACTED] before. NS Power has not purchased more than 3 cargoes annually from [REDACTED]. With the upcoming Petcoke recommendation, which will have 1 cargo of [REDACTED] supplied petcoke in 2026, if not diversified, NS Power would be exposed to 12 cargoes of solid fuel from [REDACTED]

NSPI also noted in the ROA that though the transaction did not require CROC approval, "having the entire 11 cargoes of this transaction would be expected to be noteworthy for CROC (particularly so with [REDACTED] not owning the mine assets)," suggesting that splitting the transaction between [REDACTED] and [REDACTED] "will be considered credit favorable." This is a valid assessment of the risk associated with awarding the entire 2026 supply obligation to [REDACTED]. The cost of this risk mitigation, as measured by the

incremental cost of the [REDACTED] 2026 supply relative to [REDACTED] is [REDACTED]. We confirmed the key details of the [REDACTED] contract¹⁷⁵ and [REDACTED] contract¹⁷⁶ matched the respective offers as bid.

NSPI made one other purchase of MS coal during this period. NSPI purchased a single cargo of MS coal from IMI Fuels for delivery in 2025 based on an unsolicited offer received from [REDACTED]. The selection of this incremental cargo from [REDACTED] was done prior to the April 2025 MS RFP, and the volume of the cargo (58,000 tonnes) as appropriately reflected in the RFP targets. To assess the economics of the [REDACTED] NSPI compared it to an indicative offer received from [REDACTED] on April 2, 2025, which was specified by [REDACTED] as [REDACTED] for 2025 at this time.” IMI Fuels’ unsolicited offer [REDACTED]. Fully evaluated, the [REDACTED] was about [REDACTED] than the [REDACTED] indicative offer [REDACTED]. The [REDACTED] unsolicited offer also outperformed all MS bids received in the April 2025 MS RFP, where the lowest evaluated price for 2025 supply was [REDACTED]’s offer, which was evaluated at [REDACTED] [REDACTED] more expensive than the [REDACTED]. The transaction required and received approval from CROC. We had no concerns with NSPI’s purchase of this incremental cargo from [REDACTED].

Post-CoV Petcoke RFP: On April 28, 2025, NSPI issued an RFP for petcoke for Point Aconi, seeking up to 150,000 tonnes in 2025 and up to 350,000 tonnes in 2026. These volumes match forecasted open positions of 137,500 tonnes in 2025 and 287,000 tonnes in 2026.

Seven suppliers made offers, totaling nine offers for 2025 supply and six offers for 2026 supply. All offers received were for products compatible with Point Aconi, with no offers being eliminated for operational reasons. Unfortunately, the lowest priced offer for 2025 supply (from [REDACTED]) was offered with the validity of the bid expiring on May 7, two days after bid submission (on May 5). The RFP required bids to be held valid until May 16. NSPI followed up with [REDACTED] after the RFP evaluation, but Bulk Trading explained that its bid was no longer valid.

For 2025 supply, NSPI therefore selected the next lowest priced bid, which was from [REDACTED] and which was about 1.5 percent more expensive than the [REDACTED] offer. The [REDACTED] cargoes totaled 116,000 tonnes, thereby filling about 84 percent of NSPI’s open position for 2025.

For 2026 supply, NSPI selected the lowest priced bid, which was from [REDACTED]. The offer was to provide just two cargoes (55,000 tonnes total) in 2026; thus, while [REDACTED] offer was most economic, it would cover only about 19 percent of NSPI’s forecasted open exposure in 2026. NSPI therefore selected an additional cargo from [REDACTED] for 2026, which was the next lowest priced option. That brought the total procurement for 2026 to 113,000 tonnes, or 39 percent of the forecasted open exposure. NSPI noted that it would attempt to negotiate optional cargoes from both suppliers, as per standard practice. NSPI reasoned that while the 2026 procurement leaves a significant amount of open exposure for 2026,

¹⁷⁵ [REDACTED] - 20250521 MS Coal Purchase and Sale Confirmation.”

¹⁷⁶ [REDACTED] - 20250701 Coal Supply Agreement.”

Point Aconi's "ability to switch between fuel types" allows this need to be filled with petcoke or MS coal "depending on market conditions." NSPI also noted that because the winning offers were priced based on the PACE index, which is not able to be hedged, NSPI chose to delay locking in the full 2026 petcoke position until later in 2025.

The total value of the [REDACTED] contract was estimated to be \$9,744,000 USD. The total estimated value of the [REDACTED] contract was \$9,555,000. The [REDACTED] contract¹⁷⁷ and [REDACTED] contract¹⁷⁸ matched offered terms. In our view, NSPI's decision-making was well supported and reasonable.

IV.B.7.g. Third Quarter 2025

NSPI entered into two new contracts for solid fuel supply in the third quarter of 2025. This is shown in Figure IV-22. The [REDACTED] and [REDACTED] contracts listed here are discussed in the prior section (IV.B.7.f).

Figure IV-22: NSPI New Solid Fuel Supply Contracts (Q3 2025)¹⁷⁹

Supplier	Product	Quantity (MT)	Term
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

IV.B.7.h. Fourth Quarter 2025

NSPI entered into two new contracts for solid fuel supply in the fourth quarter of 2025. This is shown in Figure IV-23.

Figure IV-23: NSPI New Solid Fuel Supply Contracts (Q4 2025)¹⁸⁰

Supplier	Product	Quantity (MT)	Term
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Petcoke RFP: On October 9, 2025, NSPI issued an RFP for petcoke, seeking up to 250,000 tonnes for delivery starting in December 2025 through 2026. This corresponded to NSPI's forecasted open petcoke position of 275,000 tonnes for 2026. Twelve suppliers submitted offers, totaling six for delivery in 2025 and eleven for delivery in 2026.

NSPI chose not to purchase any of the petcoke supply offered for 2025 delivery. In each case, bidders offered higher prices in 2025 than in 2026, and since NSPI did not need the petcoke until 2026, it found no rationale for securing the earlier purchases. Of the 2026 offers, [REDACTED] submitted the most economic

¹⁷⁷ [REDACTED] - 20250521 Petcoke Purchase and Sale Confirmation."

¹⁷⁸ [REDACTED] - 20250805 Petcoke Confirmation Letter."

¹⁷⁹ NSPI Q3 2025 FAM Report, Q3.

¹⁸⁰ NSPI Q4 2025 FAM Report, Q3.

bid. However, NSPI did not select the [REDACTED] offer, stating that “[REDACTED] has struggled with reliably scheduling their petcoke deliveries in the current contract,” noting:

For example, [REDACTED] has had to reschedule and pursue a different loading port for a Q4 2025 delivery and has indicated a need to reschedule the contracted 2026 petcoke cargo that was in the schedule for January 2026. Although [REDACTED] is within its contractual rights to reschedule the January cargo the uncertainty with regards to [REDACTED] scheduling reliability, in particular for winter supply, prompts Energy and Risk Management team to recommend limiting exposure to [REDACTED] and not contracting additional cargos with [REDACTED] until there is more certainty with [REDACTED] ability to deliver solid fuel on schedule. E&RM team will monitor [REDACTED] performance with the remaining 6 cargos of medium-sulfur coal and remaining 2 cargoes of petcoke (1 in 2025 and 1 in 2026) yet to be delivered.

In lieu of the [REDACTED] offer, NSPI selected the next two most economic offers: [REDACTED] offer of 58,000 tonnes at an evaluated delivered price [REDACTED] (or, a total estimated value of \$ [REDACTED] and [REDACTED] s offer of 58,000 tonnes at an evaluated delivered price of [REDACTED] e (or, a total estimated value of \$ [REDACTED] Both winning offers were index priced. We verified the terms of the contracts relative to the submitted offers. The [REDACTED] contract matched the supplier’s RFP offer and specified delivery of the petcoke cargo “in the second half of February 2026.”¹⁸¹ One term that changed in the [REDACTED] contract was the delivery schedule. In the bid, [REDACTED] offered a delivery period of “December 1, 2025 to December 31, 2026,” with the delivery schedule to be “mutually agreed upon between Buyer and Seller.” However, in the final contract, the delivery schedule made no reference to the as-bid delivery period, only noting that [REDACTED] would propose a planned delivery date by December 31, 2025 and that NSPI would use commercially reasonable efforts to accommodate the schedule.¹⁸² This open-ended delivery schedule language is suboptimal and should be avoided in future supply agreements. We include a recommendation on this point.

IV.B.8. Other Solid Fuel Contracts and Procurement

NSPI’s significant procurements in other services or products related to solid fuels are included in this section.

Coal Trucking Contracts, Costs: During the Audit Period, circumstances led NSPI to contract with two trucking companies to transport coal from the Point Tupper Marine Terminal area (including adjacent Bear Head) to Trenton. In total, close to 75,000 tonnes of coal were trucked at a cost of approximately [REDACTED] or \$ [REDACTED]

The first instance of trucking coal from PTMT to Trenton began with a December 15, 2023 RFP for short-term trucking services. The RFP scope of work called for up to 30,000 tonnes of coal to be shipped between “mid-January and mid-March 2024.” The need for trucking services was caused by Trenton 5

¹⁸¹ “GME - 20251107 Petcoke Supply Agreement,” section 2.1.

¹⁸² “[REDACTED] - 20251101 Confirmation Letter,” clauses 3, 4.

returning from its seasonal layup early—returning on November 5, 2023 instead of mid-December 2023, as planned. This resulted in approximately 20,000 tonnes of additional coal consumption at the Trenton plant. Without the incremental trucking deliveries and instead relying only on rail deliveries, the forecasted ending inventory for Trenton 6 as of March 31, 2024 was 25,700 tonnes, 30 percent below its three-year historical average ending inventory of 36,600 tonnes. At the time of the ROA associated with this RFP, NSPI noted that its forecasted daily consumption at Trenton 6 was 1,500 tonnes of coal per day, while the daily rail shipments of coal would be about 1,600 tonnes of coal per day, not accounting for coal delivery delays or issues (such as frozen coal). Trucking, therefore, would allow Trenton's inventories to recover, particularly at unit 6, which was expected by NSPI to be "baseloaded" and a key generating unit to meet SO₂ compliance requirements.

The December 2023 RFP received [REDACTED]. NSPI selected [REDACTED] for the contract. [REDACTED] was the lowest bidder and scored highest on the overall evaluation rubric. NSPI estimated the total contract value to be \$750,000 based on all 30,000 tonnes of coal being trucked. Actual costs were just [REDACTED] for 14,871 tonnes of coal trucked between February 5, 2024 and March 22, 2024, at an average cost of [REDACTED]. We confirmed the terms of the contract matched [REDACTED] bid.¹⁸³ We had no concerns with NSPI's procurement of this trucking contract, given the circumstances described above and in the ROA.

The next instance of trucked coal occurred in the fourth quarter of 2024. On October 4, 2024, NSPI issued an RFP for short-term trucking service for the PTMT-Trenton route, seeking up to 80,000 tonnes of trucked coal starting December 1, 2024 through March 31, 2025. Again, the impetus for the RFP was largely an earlier-than-expected recall of Trenton 5 (September 12, 2024, vs. December 1, 2024 as expected). Without the trucking services, NSPI forecasted that inventory levels on March 31, 2025 at Trenton would be negative (-53,739 tonnes). Even with 97 days of forecasted rail deliveries over the November 15, 2024 to March 31, 2025 period, NSPI would receive just 162,184 tonnes of delivered coal, while forecasting to consume 291,804 tonnes over that same period. Trucking up to 80,000 tonnes over that period would result in an ending inventory of 30,272 tonnes at Trenton 6 and 5,293 tonnes at Trenton 5.

The RFP received just one offer, which was from [REDACTED]. The bid was fully evaluated by NSPI's team and was found to be sufficient across price and non-price categories. [REDACTED] price was \$23.85/tonne, about 5 percent below [REDACTED] winning offer in the December 2023 trucking RFP. NSPI estimated the total cost of the contract to be \$ [REDACTED] assuming 80,000 tonnes of coal to be trucked. Actual costs were \$ [REDACTED] for 8,973 tonnes trucked, at an average cost of [REDACTED]. We confirmed that the pricing terms of the offer match the bid, recognizing that the "fuel

¹⁸³ "Pictou County Bulk Carriers Inc - 20240225 Trucking Services Agreement."

surcharge” was based on a variable rate.¹⁸⁴ (As we explain below, NSPI would have to terminate this contract during its term.)

To give a sense of the volumes of coal at issue, NSPI delivered a total of 3,662 railcars to Trenton in 2024. This is within NSPI’s annual estimated range of deliveries (3,500–4,500 car/year). However, compared to total railcars delivered in 2025 (4,609 cars), it is almost 21 percent lower. At 1,600 tonnes/car, NSPI had rail capacity to deliver sufficient volumes of coal during 2024 to meet consumption needs while avoiding the need for trucking. NSPI explained that operational parameters (including plant dispatch needs) and constraints (including risk of excess inventory at Trenton 5 during its seasonal layup) were reasons it did not simply maximize railcar deliveries throughout 2024.

We did have one concern. NSPI did not invite ██████ to participate in this RFP, noting that ██████ was inadvertently and unintentionally excluded from the RFP email distribution list. In fact, we observed no evidence that this RFP was sent to any parties other than ██████. This is a material lapse in practice from a team that ordinarily maximizes use of competition and good practices. ██████ should have been invited to submit a bid, particularly since it was the economic bidder in the prior trucking RFP. Not doing so deprived customers of the potential to receive a lower offer than ██████. We cannot know if ██████ would have bid, and if they had, if the bid would have been more economic than ██████. We note again that ██████ bid in the October 2024 RFP was 5 percent *lower* than ██████ winning bid in December 2023 and 6 percent lower than ██████ offer received in the December 3, 2024 RFP (explained next, below). This suggests that ██████ would have been selected even if ██████ had been invited. We include a recommendation to reduce the likelihood of such lapses in the future.

██████ performance under its contract was poor. NSPI observed that “██████ have been struggling to meet the contractual requirement for 800 [tonnes] daily delivery,” with the “actual average being approximately 400 [tonnes] per day.” NSPI noted that “██████ inability to reach contractual expectations is due to delays in mobilization of their trucking assets from an out of province job commitment.” Moreover, NSPI formally identified four safety violations by ██████ including: (1) coal spilled in the road (December 17); (2) oil spilled from ██████ truck at the Trenton scale (December 18); (3) an “axle coming off shackle” at Trenton (December 20); and (4) ash mistakenly hauled from PTMT to Trenton, instead of coal (December 3). In the midst of these incidents, NSPI met with ██████ (on December 6, 2024) for safety discussions.

In light of these performance issues, NSPI issued “another RFP for supplemental trucking” on December 3, 2024. Four offers were received, all from entities other than ██████ including ██████ (██████ offer ██████) was most economic and selected for up to 40,000 tonnes to be shipped by March 31, 2025. NSPI made the selection on December 16, 2024. We confirmed that ██████ contract

¹⁸⁴ “██████ - 20241105 Services Agreement,” PDF page 27.

matched its offer.¹⁸⁵ [REDACTED] would deliver 39,003 tonnes of coal under this contract for a total cost [REDACTED]

Meanwhile, following the broken-axle incident, which NSPI judged to be the most serious, NSPI terminated its agreement with [REDACTED] as of December 20, 2024, formally notifying [REDACTED] that same day due to its “unsatisfactory safety performance.”¹⁸⁶ As noted above, just under 9,000 tonnes of coal had been transported of the up to 80,000 tonnes called for in the contract.

Following contract termination, and following the supplemental RFP won by [REDACTED] [REDACTED] requested the ability to submit a safety mitigation plan. [REDACTED] has provided trucking services to NSPI under other contracts, and NSPI identified not outstanding safety concerns with [REDACTED] which is an ISN-certified service provider. NSPI agreed and accepted the safety mitigation plan. NSPI and [REDACTED] executed a new agreement on February 3, 2025, for the same services at the same prices, but changed the contract to (1) limit daily deliveries to 400 tonnes (from 800 tonnes in the prior contract) and (2) to incorporate [REDACTED] safety mitigation plan into the contract.¹⁸⁷ [REDACTED] trucked an incremental 11,714 tonnes of coal under this new agreement at a cost of \$296,359.94, or \$25.29/tonne.

In total, then, NSPI’s vendors trucked 59,690 tonnes of coal from PTMT to Trenton at a total cost of \$ [REDACTED]. This is shown in the table below.

Figure IV-24: Trucked Coal Volumes, Cost (December 2024-March 2025)

Supplier	Volume (tonnes)	Cost (\$/tonne)	Cost (\$)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

In our view, NSPI acted reasonably in almost all aspects of this process. The one exception is in failing to invite all regular trucking vendors to the October 2024 RFP. This led to the selection of [REDACTED] which underperformed both in delivering required volumes and in meeting safety standards. We do not conclude that inventory levels at Trenton were harmed by [REDACTED] poor performance, as Trenton inventories were around 51,000 tonnes as of March 31, 2025, which were above NSPI’s target of about 35,000 tonnes, as contemplated in the October 2024 RFP.

According to NSPI, the [REDACTED] underperformance also did not have direct incremental costs to FAM customers. We found no evidence to the contrary. The spilled coal (which was quite small) was cleaned up at [REDACTED] expense. The spilled oil was cleaned up with onsite spill kits by the [REDACTED] truck driver and the coal handling team at Trenton, with no environmental remediation or reporting. The mistaken

¹⁸⁵ “[REDACTED] - 20250101 Trucking Services Agreement.”

¹⁸⁶ “[REDACTED] - 20241220 Termination Letter to 20241105 Service Agreement.”

¹⁸⁷ “[REDACTED] - 20250203 Services Agreement.”

delivery of ash (25 tonnes) to Trenton, which occurred on December 3, 2024, was rejected by Trenton personnel prior to unloading and returned to Bear Head to deposit the ash. NSPI received one truck cargo of coal at Trenton that same day and was charged for one cargo (304.28 tonnes at a cost of \$ [REDACTED])

It is possible NSPI would have been better off contracting with [REDACTED] from the beginning. Again, we cannot know what [REDACTED] would have offered in the October 2024 RFP had they been invited. Ultimately, [REDACTED] per-tonne cost of trucking [REDACTED] was higher than [REDACTED] (\$24.91/tonne), so we cannot point to a clear incremental cost to FAM customers. Moreover, once the [REDACTED] contract was awarded pursuant to the October 2024 RFP, NSPI acted prudently by (1) tracking [REDACTED] performance under the contract, (2) issuing a supplemental trucking RFP quickly upon observing [REDACTED] poor performance, (3) administering the supplemental RFP in a reasonable manner and selecting the most economic offer, (4) terminating [REDACTED] contract upon repeated safety violations, (5) allowing [REDACTED] to provide a safety mitigation plan and executing a new, lower risk contract with [REDACTED] (which again, was lower cost than [REDACTED] and (6) maximizing the volumes delivered by [REDACTED] (~39,000 tonnes vs. a contract maximum of 40,000 tonnes), not [REDACTED] (11,714 tonnes). We therefore do not recommend any disallowances associated with these contracts.

Stepping back, we again note that NSPI incurred approximately [REDACTED] in incremental trucking costs to keep sufficient inventories at Trenton. As is shown in the table below, trucking is about 97 percent higher cost than rail transport from PTMT to Trenton.

Figure IV-25: Coal Transportation Cost by Transportation Type (2024-2025)

Transportation Type	Quantity (MT)	Cost (\$)	Unit Cost (\$/MT)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Trucking needs may persist, particularly if Trenton 5's seasonal layup period is shortened. The impact of the loss of Trenton 6's domestic supply of coal (from Stellarton) is having an impact, as that coal did not come from PTMT but rather the nearby Stellarton Mine. Now, 100 percent of both Trenton 5 and Trenton 6's coal supply comes from PTMT. NSPI explained that it is having dedicated weekly meetings to maximize coal availability for Trenton's winter consumption and introduced a metric into its Commercial Incentive program that incentivizes employees to eliminate trucking from PTMT to Trenton.

Railcar Replacements, Purchases, and Leases: During the Audit Period, NSPI had 136 railcars under lease from three vendors with ages ranging from 30 to 46 years.¹⁸⁸ (NSPI does not own any railcars.) Freight car lives have traditionally been considered to be 50 years, and the Interchange Rules of the Association of America Railroads ("AAR") has limited the life of freight cars to 50 years from the

¹⁸⁸ Railcar ages are as of January 1, 2024.

date originally built (though exceptions exist).¹⁸⁹ The table below shows the details of NSPI's complete railcar fleet under lease, including the lessor and the year in which NSPI first started leasing and using the railcars. The final row shows the total number of cars and the weighted average life of the fleet.

Figure IV-26: NSPI's Leased Railcar Fleet¹⁹⁰

Supplier	Number of cars	Age of cars	Year of first NSPI use
	4	30	2025
	45	33	2025
	11	34	2025
	5	43	2019
	18	46	2019
	1	43	2010
	52	44	2010
	136	39.4	

During the Audit Period, NSPI took several actions related to its railcar fleet. NSPI's lease with [REDACTED] was to end on January 31, 2025. In anticipation of this, on October 4, 2024, NSPI issued an RFP for railcars seeking up to 50 railcars for lease with a start date of February 2025; proponents were also encouraged to submit proposals for additional cars in increments of 10 cars, and up to a maximum of 100 cars. Seven suppliers were invited and NSPI received proposals from two suppliers (W [REDACTED] [REDACTED]). Both proponents offered 53 railcars for a three-year term, but [REDACTED] offer was substantially less costly (with a total estimated cost [REDACTED] vs. [REDACTED] estimated cost of \$ [REDACTED] USD). [REDACTED] offered both a lower lease cost per car (\$ [REDACTED] and mobilization costs per car (\$ [REDACTED]).

Notably, the offers from both Progress and [REDACTED] were for aluminum cars, which NSPI had no experience using. (NSPI's railcars have been invariably steel, including the [REDACTED] cars under lease at that time.) To better understand their suitability, NSPI reached out to an American utility with such experience and received positive feedback. NSPI was informed from potential suppliers and industry reports at the time of the RFP that steel railcars had largely been retired, while new railcars were largely aluminum. With no steel alternatives to choose from, NSPI determined that aluminum cars would be suitable (and have reported no significant challenges associated with the aluminum cars to date).

During the RFP period, NSPI was also considering its options under its existing lease with [REDACTED] for the 53 steel railcars included in the figure above. The lease required NSPI to return railcars "in the same condition as when delivered" by [REDACTED] to NSPI, and "suitable for interchange service."¹⁹¹

¹⁸⁹ See, for example, Dawson, Richard W., *et al.*, "New AAR Procedure Permitting Freight Car Life Beyond 50 Years," ASME International Mechanical Engineering Congress and Exposition, February 5, 2008, available at: <https://asmedigitalcollection.asme.org/IMECE/proceedings-abstract/IMECE2005/42210/127/301654>.

¹⁹⁰ Railcar ages are as of January 1, 2024.

¹⁹¹ "[REDACTED] - 20101221 Lease Agreement - [REDACTED] and NSPI," section 10.

Alternatively, NSPI could purchase and scrap cars in lieu of paying for these repairs. Under its lease, NSPI had the option to purchase up to five cars for \$ [REDACTED] USD.¹⁹²

In assessing its options, NSPI requested [REDACTED] undertake an assessment of the [REDACTED] fleet. [REDACTED] role is important, as [REDACTED] has the right to refuse any railcar that is not safe for transportation or does not meet applicable AAR standards. [REDACTED] advised that 19 of the 53 cars were in “Bad Order status,” which refers to railcars that are mechanically defective or have safety violations.¹⁹³ [REDACTED] report stated the following (“AFCX” cars are the [REDACTED] railcars):

At this moment there are currently 19 AFCX cars in Bad Order status, some dating back over 2 years, in the last 7 days alone we have taken 3 cars out of service for major structural issues. [REDACTED]/NSER has voiced our concerns many times over the past 5 years regarding the condition of said cars and the rapid deterioration of not only the structural integrity, but also the dump system components. The risk associated with the transportation of the fleet is increasing.

[REDACTED] noted that “[a]ll cars currently in bad order status have at least one or more of the uprights and/or crossmembers missing,” which “along with the deterioration of the other structural components” introduces “a risk of complete failure.” [REDACTED] also concluded that “all” [REDACTED] cars “show considerable amount of metal deterioration and fatigue of the operating doors,” which are the doors on the underside of the car that open at Trenton to allow coal to enter the plant’s hoppers below. [REDACTED] noted:

Our car repair personnel have been installing new plates at these locations, however the surrounding material is in such poor condition that in most instances there is insufficient material to weld to. This along with numerous operating valve and dump cylinder failures the labor and material cost to repair and/or replace would be extremely high.

[REDACTED] provided photographic evidence of its findings in its report. [REDACTED] concluded:

The AFCX fleet is in extremely poor condition. The down time and extent of repairs needed to return cars to a safe condition have grown exponentially over the past few years, most of these cars are roughly 45 years old and are showing that age. As our Bad Order total rises it will continue to, and more deeply impact both NSER’s and NSP’s operations as the weeks and months go on, winter is fast approaching and with it comes the added difficulties of unloading, use of the shaker and slicer will only increase the deterioration.

Using outside help from [REDACTED] NSPI estimated the repair costs of the railcars to be between \$ [REDACTED] and \$ [REDACTED] per car, though noted that the repair costs are subject to significant uncertainty. The purchase-and-scrap option was therefore economic for the first five cars, and had a total estimated cost of \$ [REDACTED] USD.

¹⁹² [REDACTED] - 20221230 Rider No.4,” section 12 (D).

¹⁹³ See, for example, Union Pacific, “Customer Glossary,” available at: <https://www.up.com/customers/glossary/a-c/index.htm>.

In light of these findings, NSPI notified ██████████ it intended to purchase at least five railcars under its existing option. ██████████ offered NSPI the option to purchase the remaining 48 railcars for ██████████/car. NSPI negotiated this price down to \$ ██████████/car.

On December 9, 2024, NSPI determined to buyout and scrap the 19 of the 53 ██████████ cars that were determined to be in Bad Order by ██████████. The cost of this action was estimated to be ██████████ USD, which included five cars purchased at \$ ██████████/car USD and the remaining fourteen at \$ ██████████. NSPI noted in its ROA that it “expect[ed] to recommend a buyout of the remaining 34 [██████████ steel] cars pending successful conclusion of the trial period with the aluminum cars.” The “trial” period is explained next.

Turning back to the RFP results, NSPI selected 30 ██████████ cars to lease beginning February 1, 2025. To mitigate the risk associated with using aluminum cars, NSPI signed a trial six-month lease with ██████████ to start. During this period, NSPI also extended its existing lease with ██████████ for the remaining 34 steel railcars for four months through May 30, 2025. No lease extension was executed, but ██████████ allowed the existing lease to extend on a month-by-month basis.

NSPI executed an agreement with ██████████ to purchase the initial five steel railcars on February 13, 2025, and prices match the ROA.¹⁹⁴ NSPI did not execute any amendments to its ██████████ lease to extend it to May 30, 2025, but noted in the ROA that “██████████ [had] agreed to extend the lease on a month-to-month basis at the current lease rates to enable sufficient time for NS Power to test the suitability of aluminum cars on the PTMT-Trenton circuit.” The ROA states that the “current lease rate” was \$ ██████████/car, which is inclusive of a withholding tax alongside the actual lease rate of \$ ██████████.¹⁹⁵ Ultimately, we had no concerns regarding the services provided by ██████████.

The cost of the six-month trial period with ██████████ was estimated to be \$ ██████████ USD, which equaled \$ ██████████ car times 30 cars (for six months), plus \$ ██████████ USD/car mobilization charge for 30 cars (one-time cost), plus an incremental \$ ██████████ USD charge by Progress to NSPI for the trial period. However, in the contract provided by NSPI, the lease rate was listed as \$0.00/car/month.¹⁹⁶ NSPI explained only that when ██████████ prepared the contract, this zero dollar price was included by ██████████. The contract did require NSPI to pay the “shop” cost incurred by ██████████.¹⁹⁷ Total costs invoiced by Progress and paid by NSPI for the shop costs was \$ ██████████.

NSPI received the first 21 of the ██████████ cars on March 13, 2025, with the remainder arriving on March 25, 2025. These cars arrived later than NSPI expected, limiting the time NSPI had to trial the cars. On April 1, 2025, NSPI submitted an ROA indicating that all 30 cars had been tested through being

¹⁹⁴ “██████████ - 20250213 Purchase Agreement and Partial Lease Termination.”

¹⁹⁵ “██████████ - 20221230 Rider No.4,” section 5, 12 (B).

¹⁹⁶ “██████████ - 20250111 Schedule No. 2 to 20051118 Master Railcar Lease Agreement.”

¹⁹⁷ “██████████ - 20250111 Schedule No. 2 to 20051118 Master Railcar Lease Agreement,” section 4.

loaded at PTMT, railed to Trenton, and unloaded. NSPI indicated that “[o]nly minor issues were observed, requiring small modifications to car inspection and coal release protocols.” NSPI and its contractors (██████████), therefore, “anticipate[d] a successful transition to the full fleet of 60 aluminum cars.” As such, NSPI approved the scrapping of all remaining steel ██████████ railcars and a termination of the ██████████ lease. The cost of this option was \$██████████ USD, which equaled the \$██████████ USD/car purchase rate times the remaining 34 cars. We confirmed the associated purchase and termination agreement with ██████████ matched these terms.¹⁹⁸

As for ██████████ ██████████ NSPI approved the pursuit of a 36-month lease with ██████████ ██████████ for 60 railcars. The cost of this lease would be \$██████████ USD, which equaled the ██████████ USD/car rate (as bid) for 60 cars and 36 months, plus the one-time mobilization cost for the 30 cars NSPI had not yet received at a rate of \$██████████ USD/car. The mobilization rate did not match Progress’ offer, which was \$██████████ USD/car. NSPI stated that “The mobilization cost slightly increased since the estimate from the first recommendation...due to the fact that it was quoted in 2024 and did not include the fuel and carbon surcharges.” We confirmed that the lease ultimately reflected some key terms of ██████████ offer, including the 60 railcars and \$██████████/██████████ /month lease rate.¹⁹⁹ However, the term set in the lease agreement was five years, not three (though NSPI has a unilateral option to terminate the lease at the end of year 3 and year 4) and we saw no evidence of the per-car mobilization cost.²⁰⁰ The lease also abbreviated the “zero-cost” trial period for the initial 30 railcars, which was supposed to last for 90 days “from the first day of the first month following delivery of the last Car.”²⁰¹ As noted above, the last of the railcars was delivered on March 25, 2025, meaning the “first day of the first month following delivery of the last Car” would be April 1, 2025. That would set the 90-day trial period as ending June 30, 2025; however, in the post-trial period lease, the term for these 30 cars began May 1, 2025. This means NSPI would pay for two months of lease costs for 30 cars that were supposed to be zero cost. The incremental cost is \$██████████ USD (██████████ x 30 cars x 2 months). NSPI reasonably explained that it completed the testing of the cars early, which allowed NSPI to access the additional 30 cars (of the 60-car set) sooner, avoiding adverse impacts to coal deliveries that could have increased costs to customers beyond the \$██████████ USD of incremental cost associated with the lease.

In our view, this process was generally reasonable, with some highlights of good practice, but was marred by some poor practices. The decision to scrap the 53 ██████████ railcars at a total cost of \$██████████ USD was reasonable. NSPI relied upon ██████████ to provide a condition assessment, and that assessment indicated that the cars were in poor condition. NSPI also used ██████████ to develop a cost estimate of returning the cars to working order (as required by the lease with ██████████) and found

198 “██████████ - 20250418 Purchase Agreement and Lease Termination.”

199 “██████████ - 20250506 Schedule No. 3 to 20051118 Master Railcar Lease Agreement.”

200 “██████████ - 20250506 Schedule No. 3 to 20051118 Master Railcar Lease Agreement.”

201 “██████████ - 20250111 Schedule No. 2 to 20051118 Master Railcar Lease Agreement,” PDF page 1.

that cost to be materially higher than the scrapping option. Moreover, NSPI mitigated the cost of this option by scrapping cars to [REDACTED] for \$ [REDACTED] on January 19, 2026.

The selection of [REDACTED] in the RFP was also reasonable and the product of a competitive solicitation. NSPI's decision to pursue a trial period to ensure the suitability of aluminum cars was reasonable and had a fairly minor incremental cost ([REDACTED] USD, plus the four-month [REDACTED] extension of \$ [REDACTED] USD). The trial period itself was short (just a few days for some cars) and did not include winter conditions, but was at least conducted and documented. NSPI recognized the risks of winter usage of the aluminum railcars, including the vulnerability of the aluminum cars to use of Trenton's "slicer," which is a mechanical apparatus that helps break up frozen coal to allow it to be released from train cars into Trenton's hopper. (NSPI purchased a new slicer during the Audit Period at a cost of [REDACTED] (a non-FAM cost), and reported no concerns or problems with the use of the slicer with the aluminum cars.) The decision to finalize a long-term lease with [REDACTED] at the end of the trial period was also reasonable, subject to one comment below.

Separate from NSPI's decision-making in this matter, NSPI's contracting methods were substandard. NSPI did not formally execute a four-month lease extension with [REDACTED]. NSPI's leases with [REDACTED] also did not fully match the terms of the ROAs, as already explained. It is reasonable and in fact encouraged for NSPI to negotiate and achieve better contractual terms following ROA development and approval, and NSPI's ability to secure a zero-dollar lease rate for the trial period was a substantially positive outcome. However, key terms, including mobilization costs, were not documented.

Rail Line Maintenance: While [REDACTED] is responsible for maintaining its track between PTMT and Trenton, NSPI is responsible for maintaining rail infrastructure within its property boundaries. During the Audit Period, NSPI maintained its relationship with inspection service provider, [REDACTED] to provide regular inspections. In total [REDACTED] provided 21 inspections for a cost of \$ [REDACTED]. April and June 2024 inspections identified certain defects and identified corrective measures needed at both Trenton and PTMT to avoid the risk of derailments. In response, NSPI issued an RFP on July 26, 2024 to three potential service providers. Only one offer was received. [REDACTED] Systems (" [REDACTED] ") was selected at their offer of approximately \$ [REDACTED] which included \$ [REDACTED] 0 for work at Trenton and \$ [REDACTED] for work at PTMT. NSPI did not provide a contract related to [REDACTED] work, but did provide invoices demonstrating that the total cost of services was ultimately \$ [REDACTED]. NSPI also provided the Purchase Order for the work, which included a cost of \$ [REDACTED].

[REDACTED] would complete three other paid tasks for NSPI. The first was a small repair (\$ [REDACTED] at Trenton based on a [REDACTED] recommendation. Again, no contract was provided related to this work but an invoice confirming the \$ [REDACTED] charge was provided. NSPI also provided the Purchase Order for the work, which included a cost of \$ [REDACTED]. NSPI explained that the purchase order was established in

202 "[REDACTED] - PO 2140911 (TRAN0051)."

203 "[REDACTED] - PO 2148554 (TRAN0059)."

January based on the plant's initial cost estimate for the work, but upon further scoping of the work for completion in June, the revised estimate indicated that the actual cost would be lower than originally anticipated.

The second was a scope of work change order needed related to ongoing work at Trenton for \$ [REDACTED]. NSPI did not provide a contract, but did provide the invoice, which matched the \$ [REDACTED] price. NSPI also provided the Purchase Order for the work, which included a cost of \$ [REDACTED] a difference of about \$ [REDACTED] from the invoiced amount. NSPI explained that at the time this purchase order was created, the cost estimate it was based on was slightly higher than the actual costs incurred to complete the work, which was attributable to timing differences and subsequent refinement of the cost estimate. The third item was for additional repairs at both Trenton and PTMT related to [REDACTED] inspections that identified multiple cracks in rails that needed replacement in order to avoid derailments. NSPI again issued an RFP for this summer 2025 work, and again only [REDACTED] responded with a bid of approximately \$ [REDACTED]. NSPI did not provide the contract for this work but provided an invoice from [REDACTED] showing the total cost of \$ [REDACTED]. NSPI also provided the Purchase Order for the work, which matched [REDACTED] bid of \$ [REDACTED].

NSPI's reliance on Purchase Orders (as opposed to contracts) for its [REDACTED] transactions is an outlier from NSPI's normal and common practice for its suppliers of FAM-related products and services. The Purchase Orders contain key protections for NSPI and their customers. The Purchase Orders incorporate "NSPI Standard Terms and Conditions," which are appended to the Purchase Orders.²⁰⁶ As would be expected in any "standard" contractual terms and conditions, NSPI refers to the Purchase Order to fill in the details of a transaction. For example, the "Delivery" clause states: "The Seller shall deliver the Work to the delivery location, if applicable, and by no later than the delivery date, both as may be specified in the PO."²⁰⁷ In the case of the [REDACTED] Purchase Orders, there was not always a reference to the timing of the work.²⁰⁸ Another example: the scope of work to be delivered would also only be included in the Purchase Order, and the Purchase Order specification was limited, such as in the Purchase Order for the track work at Trenton and Point Tupper in 2024, where the work scope was stated only as "2024 Track Maintenance at Trenton" and "2024 PTMT Track Maintenance,"²⁰⁹ with no additional information regarding the specific scope to be delivered by [REDACTED]. In our view, these practices can be enhanced and should be, as the dollars at stake are non-trivial. [REDACTED] total invoiced costs during the Audit Period equaled \$ [REDACTED] all of which was transacted under Purchase

²⁰⁴ "[REDACTED] - PO 2148554 (TRAN0064)."

²⁰⁵ "[REDACTED] - PO 2170405 (TRAN0061)."

²⁰⁶ See, for example, "[REDACTED] - PO 2148554 (TRAN0059)."

²⁰⁷ "[REDACTED] - PO 2148554 (TRAN0059)," PDF page 5.

²⁰⁸ "[REDACTED] - PO 2148554 (TRAN0064)," PDF page 1; see also "[REDACTED] - PO 2140911 (TRAN0051)," PDF page 1.

²⁰⁹ "[REDACTED] - PO 2140911 (TRAN0051)," PDF page 1.

Orders. We include a recommendation that NSPI institute a process to ensure that Purchase Orders include key information that is required in NSPI's Standard Terms and Conditions.

A final rail maintenance item occurred in June 2025 when NSPI approved the payment of 50% of required rail maintenance costs on a portion of [REDACTED] track between PTMT and Trenton that the parties refer to as the "coal spur," a section of track just outside NSPI's property line near Point Tupper. NSPI does not own this portion of the rail circuit; however, neither does [REDACTED]. The land is instead owned by Nova Scotia Lands, and this portion of the rail circuit is only used by NSPI and [REDACTED] (for the purpose of serving NSPI's needs). Despite no contractual obligation to do so, NSPI agreed to fund 50% of [REDACTED] costs for repairing the track to allow for continued safe use of the track for NSPI's needs. NSPI confirmed its willingness to pay in a June 17, 2025 letter to [REDACTED] but noted that its maximum payment would be \$ [REDACTED] which equaled 50% of [REDACTED] total cost estimate of \$ [REDACTED]. NSPI also noted in the letter that NSPI's contribution to the work "should not be taken to, and does not, create any present or future obligation of Nova Scotia Power to maintain or contribute to the cost of the maintenance of any facilities, except as expressly provided." We took no issue with NSPI's decision to fund track maintenance on the coal spur, given NSPI's need to maintain usage of the track and the risk associated with challenging [REDACTED] on its cost responsibility for this work.

Ocean Freight Shipping: One of the more material transactions of the Audit Period in terms of total cost related to NSPI's selection of [REDACTED] to provide ocean freight shipping services. NSPI issued an RFP for these services on July 15, 2025, with [REDACTED] parties invited to bid, including [REDACTED] the incumbent provider. [REDACTED]
[REDACTED] The RFP specified contractual volumes by year (through 2028), source locations (Colombia, U.S. east coast, U.S. Gulf coast or Great Lakes), and delivery locations (International Pier, Point Tupper Marine Terminal).

[REDACTED] offer was substantially superior to Norden's. [REDACTED] pricing was moderately lower than [REDACTED] but [REDACTED] also scored higher on non-price factors. [REDACTED] also failed two eligibility requirements of the RFP, with one related to its safety record and another related to insurance coverage demonstrations. Moreover, [REDACTED] vessels are too large to provide deliveries to the International Pier, leading [REDACTED] to the INP.

[REDACTED] offer represented [REDACTED] price increase from its existing contract, which was set to expire at the end of 2025; however, the offer kept rates fixed through 2028, at which point rates would increase by [REDACTED] for 2029. The offer also includes two option years for 2030 and 2031 if NSPI requires coal-related services in those years. The total estimated value for the four-year contract was estimated by NSPI to be \$ [REDACTED] USD, based on forecasted shipping volumes.

We verified contract terms matched [REDACTED] offer as evaluated.²¹⁰ NSPI's selection of [REDACTED] was reasonable and based on a well-conducted competitive RFP. Participation was limited, but we observed no causes by NSPI for that low participation. In fact, we noted that NSPI engaged a third-party firm ([REDACTED]) to distribute the RFP material to their industry contacts. NSPI suggested that because vessel owners may not have additional business in the region, their economics to providing these services are limited, which likely harmed participation in the RFP. Moreover, NSPI's decision to secure a contract for a four-year term with two one-year options was also reasonable, given current policy expectations for the cessation of coal-fired generation in 2030 and beyond. We note that NSPI executed this agreement on January 26, 2026, and therefore secured a one-month extension of its existing agreement with [REDACTED] to effectuate the six ocean-based coal shipments it had scheduled for January 2026. The one-month extension agreement adopted the 2026 shipping rates specified by [REDACTED] in its RFP bid and ultimately memorialized in the January 26, 2026 contract with [REDACTED]. We verified the terms of the one-month extension matched the ROA;²¹¹ the estimated value of the extension was \$ [REDACTED].

Rail Transportation From PTMT to Trenton: [REDACTED]

(“[REDACTED]” has long provided NSPI with railroad transportation services from Point Tupper Marine Terminal to the Trenton units, delivering solid fuel using rail cars provided and leased by NSPI. NSPI's contract term with [REDACTED] was set to expire on December 31, 2025. In September 2025, NSPI decided to exercise its option to extend the [REDACTED] agreement for two additional years, through December 31, 2027. Under the existing contract, such an extension would require rates to increase by the greater of the Nova Scotia consumer price index (“CPI”) [REDACTED] per year.²¹² NSPI formally exercised its right by letter dated September 25, 2025.²¹³ The contract's estimated value [REDACTED] which factored in [REDACTED] increases in shipping rates for both 2026 and 2027. NSPI assessed the value of this contract against a trucking alternative, which was evaluated as [REDACTED] more expensive than the [REDACTED] rail contract.

NSPI's extension of the [REDACTED] agreement was reasonable. [REDACTED]

[REDACTED] Recall, too, that in the prior audit period, NSPI conducted an RFP for coal transportation from PTMT to Trenton, inviting both rail and trucking options. [REDACTED] offer was [REDACTED] economic than the trucking alternative in that RFP.²¹⁴

Services Contract at International Pier, Point Tupper Marine Terminal: Another material contract extension executed during the Audit Period was a 2.5-year extension of NSPI's agreements with [REDACTED]”) for stevedoring and fuel handling services at International Pier and Point

²¹⁰ “[REDACTED] - 20260126 Contract of Affreightment.”

²¹¹ “[REDACTED] - 20251218 Extension to 20130304 Contract of Affreightment.”

²¹² “[REDACTED] - 20230101 NSPI Amendment 2023,” Second Amended Schedule C.

²¹³ “[REDACTED] - 20250925 Contract Term Extension.”

²¹⁴ 2022-2023 Bates White Audit Report, section IV.B.8.

Tupper Marine Terminal. [REDACTED] was last selected competitively for these services in a 2019 RFP and has provided services to NSPI ever since. [REDACTED] contracts for each pier were set to expire on June 30, 2024.²¹⁵ In pursuing the contract extension, [REDACTED] offered (and NSPI accepted) a [REDACTED] price [REDACTED] in 2024, [REDACTED] in 2025, and 2.5% increase in 2026. NSPI noted that these price [REDACTED] were competitive to inflation as well as [REDACTED] established relationship with [REDACTED] NSPI noted, too, that [REDACTED] was working with NSPI on several projects (including at PTMT) which included upgrades to prevent and manage coal sloughing.

NSPI's decision to extend [REDACTED] contract appears reasonable. We confirmed that contract terms matched [REDACTED] submission to NSPI in support of the extension.²¹⁶ NSPI's total estimated contract value is [REDACTED] over the 2.5-year term.

Coal Loading Inspection Services: In October 2023, NSPI issued an RFP for quality control inspection services at all NSPI load ports for solid fuel. The RFP was issued in advance of the December 31, 2023 contract expiration of the incumbent provider, [REDACTED]. [REDACTED] NSPI sent the RFP to six vendors and received three responses. [REDACTED] offer scored the highest in the evaluation, which included the lowest price offer; [REDACTED] offer was [REDACTED] lower priced than the second best offer. NSPI noted [REDACTED] "excellent" service record in providing these services in prior years. The total contract value for the three-year term was estimated to be [REDACTED]. [REDACTED] NSPI's evaluation of the RFP was reasonable and selected the lowest priced offer as evaluated. We note that this RFP, which was conducted in 2023, was provided as part of this current audit as NSPI noted that it was "not filed in the Fuels Data Cart, but rather in the NSPI Procurement System." NSPI explained that "[t]his was flagged when the contract was executed in June 2024, at which time the ROA was also filed in the Fuels Data Cart."

Limestone Quarry Services: NSPI consumes limestone in its boiler at Point Aconi as part of its unique fluidized bed design. The limestone comes from the NSPI-owned Glen Morrison limestone quarry in Cape Breton. NSPI had an agreement with [REDACTED] [REDACTED] for the processing, loading, and delivering of limestone to Point Aconi that expired July 1, 2024.²¹⁷ In anticipation of this expiration, NSPI issued an RFP on April 24, 2024 seeking a five-year contract term for limestone quarry services.

Offers from the incumbent ([REDACTED]) and [REDACTED] were received. The evaluation process required clarification discussions with both proponents, so NSPI extended the overall contracting process and executed a short-term extension to [REDACTED] existing agreement through August 31,

²¹⁵ [REDACTED] - 20220228 Point Tupper - Amendment No.1"; [REDACTED] - 20221115 INP Amendment No.3."

²¹⁶ [REDACTED] - 20240630 INP_Services_Agreement_Fourth_Amendment;" [REDACTED] - 20240630 PTMT Second Amending Agreement."

²¹⁷ "NCL - 20200101 Northern_Contracting_Limited_First_Amending_Agreement_Glen_Morrison.pdf," PDF page 1.

2024. [REDACTED] existing rates were maintained for this period, which we confirmed in the extension agreement.²¹⁸

In conducting the RFP, NSPI used a “best and final offer” option given the closeness of the two offers as originally received. [REDACTED] improved its offer in the BAFO process, while [REDACTED] did not. Even with [REDACTED] improved pricing, the price evaluation was close. NSPI assessed the two bids across five different limestone tonnage scenarios, a prudent decision given the uncertainty of Point Aconi’s annual generation output, which is largely determined by the economics of the fleet. In four of five scenarios, [REDACTED] offer was superior, offering savings between \$0.1 million to \$2.3 million compared to [REDACTED] offer. [REDACTED] offer, which had a high fixed cost component, only outperformed in the highest consumption case, whereby [REDACTED] offer would provide \$0.8 million in savings. NSPI’s subject matter experts noted [REDACTED] strong track record of performance in providing these services as the incumbent. NSPI therefore reasonably selected [REDACTED] for these services.

The total value of the contract was estimated to be \$[REDACTED]. We confirmed the contract matched [REDACTED] BAFO.²¹⁹ Compared with [REDACTED] prior rate (\$[REDACTED]/tonne),²²⁰ the new rate (\$[REDACTED]/[REDACTED])²²¹ represents [REDACTED]. However, the new agreement removed contract minimum volumes, which if not met, would trigger shortfall payments, as was present in the prior agreement.²²² We noted shortfall payments of approximately \$[REDACTED] in the prior audit period.²²³

Ash Haulage Services: NSPI requires ash haulage services for both Point Aconi and Lingan, including specialized ash haulage services from Point Aconi due to the caustic ash its fuel mix produces (coal, petcoke, and limestone) when combined with water. NSPI’s existing contract for these services with [REDACTED] was set to expire on June 30, 2024.²²⁴ To ensure continued service, NSPI issued an RFP for these services on May 8, 2024, inviting nine potential vendors. Three bids were received. The highest scoring bid was the incumbent’s, [REDACTED]. Another bidder, [REDACTED], submitted the lowest price offer, but scored considerably lower than [REDACTED] on safety, environmental, and experience non-price scores. [REDACTED] also rescinded its offer on June 6, 2024. [REDACTED] was reasonably selected for this work, which had an estimated

²¹⁸ “NCL - 20240630 Extension Agreement - Glen Morrison Service Agreement.”

²¹⁹ “NCL - 20240901 Limestone Quarry Services Agreement.”

²²⁰ “NCL - 20200101 NORTHERN_CONTRACTING LTD_NSPI_Limestone,” Schedule A section 2.1.

²²¹ “NCL - 20240901 Limestone Quarry Services Agreement,” Schedule A, section 1.1.

²²² NCL - 20200101 NORTHERN_CONTRACTING LTD_NSPI_Limestone.pdf, Schedule A section 2.4(e).

²²³ 2022-2023 Bates White Audit Report, section IV.B.8.

²²⁴ “NCL - 20190701 [REDACTED] POA Ash Services,” section 1.1.7.

contract value of \$ [REDACTED] We confirmed that the separate three-year contracts for Point Aconi²²⁵ and Lingan²²⁶ had terms that matched [REDACTED] offer.

Coal Sales Agreement: On September 3, 2025, NSPI agreed to a five-year extension to its existing coal sales agreement with [REDACTED].²²⁷ Under the agreement, NSPI will sell 500-1,094 tonnes per year over the contract term to the government for [REDACTED]/tonne to \$ [REDACTED]/tonne, depending on the year, for a total contract value of [REDACTED] These coal sales will generate revenues credited to FAM customers.

IV.B.9. Bates White's 2022-2023 Audit Recommendations

In our report for the prior audit period, we offered one solid fuel procurement recommendation. We concluded and recommended:

Conclusion IV-18: As NSPI's solid fuel consumption continues to fall, NSPI may face more difficult conditions in contracting for products and services dependent on spreading costs over large quantities. One example of this issue was seen with [REDACTED] supply agreement for limestone at Point Aconi. Lower petcoke consumption at Point Aconi drove limestone consumption below contractual minimums, leading to shortfall payments under the contract. Smaller consumption and throughput can mean higher per-unit prices. NSPI must continue to leverage competition and good faith negotiations to balance the rates, terms, and conditions of these contracts. Moreover, NSPI should model any shortfall payments in its commitment and dispatch decisions. **(Recommendation IV-1)**

Recommendation IV-1: NSPI should seek to model fuel minimum volume payment penalties it faces in its commitment and dispatch.

NSPI accepted this recommendation. We noted that NSPI's acceptance and response to our recommendation was positive.²²⁸ In its February 2026 FAM Audit Action Plan Update, NSPI stated:

NS Power analyzed all contracts which have minimum volumes and discussed the matter with the FAM SWG. The analysis concluded that there are no changes required in the way contracts are presently modeled. In addition, the contract which precipitated this recommendation has been renegotiated and no longer contains minimum volume payment.

NSPI's reference to "the contract which precipitated this recommendation" is the contract for limestone supply from [REDACTED] As noted above, that contract expired during the Audit Period and was replaced by a contract with no such minimum volume provisions. We consider this recommendation fully addressed.

²²⁵ "NCL - 20240629 First Amending Agreement (Ash Management Lingan)."

²²⁶ "NCL - 20240629 First Amending Agreement (ASH HAULAGE POA)."

²²⁷ "Public Works - 20250903 Amending Agreement - Sale of Domestic Coal to Public Works."

²²⁸ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 23.

IV.C. Conclusions

Conclusion IV-1: Consumption of solid fuel was 26.9% higher than the base cost of fuel forecast, due largely to lower than forecasted Surplus Energy, changes in fuel blends, and the sulfur emissions CoV. NSPI's Audit Period solid fuel consumption increased by 5.0 percent relative to the prior audit period but remains well below historical levels.

Conclusion IV-2: NSPI remains highly reliant on imported sources of solid fuel, with 90.7 percent of all non-biomass solid fuel coming from imported sources. Consumption of South American coal imports increased to 52 percent of all solid fuel consumed (up from 30 percent in the prior audit period).

Conclusion IV-3: NSPI has no active sources of domestic coal and received just a small leftover shipment of [REDACTED] coal during the Audit Period.

Conclusion IV-4: NSPI altered fuel blends at its plants in response to SO₂ emissions constraints. Petcoke consumption at Point Aconi was reduced from 75.9 percent of the blend in the prior audit period to just 43.9 percent in this Audit Period, though was returned to 80 percent at the end of the Audit Period after receipt of the CoV. At Trenton, NSPI greatly increased the percentage of LSL coal in this mix—reaching as high as 100 percent LSL at Trenton 5 and 6 for a period of time—but limited LSL consumption at Lingan due to the threat of opacity violations and derates. To lower sulfur content of the Lingan blends, NSPI removed petcoke from Lingan's blend and increased use of MS coal.

Conclusion IV-5: Following a volatile period of market pricing in the prior audit period, coal prices moderated and enjoyed reduced volatility during the 2024-2025 period. The [REDACTED], which is the index against which many of NSPI's coal contracts settle, ranged between just under \$ [REDACTED] and just under [REDACTED] (USD) during the Audit Period.

Conclusion IV-6: Solid fuel prices used in dispatch fell during this Audit Period with broader market conditions. Two outlying periods of data are the steep increase in the fuel component cost for Trenton 5 and Trenton 6 over the November 20, 2024 to January 2, 2025 period, during which period NSPI adjusted the marginal costs of both Trenton 5 and Trenton 6 to be based on the marginal cost of HFO instead of solid fuel. NSPI explained that due to low inventory at Trenton and challenges in maintaining inventories as consumption ramped up at both units into the winter season.

Conclusion IV-7: NSPI's codified processes for solid fuel procurement as found in the Fuel Manual remain sound.

Conclusion IV-8: NSPI's execution of solid fuel RFPs during the Audit Period was generally sound and typically resulted in reasonable contracts. NSPI's RFP process is well designed and encourages healthy participation by suppliers. Evidence of the success of the RFP process can be measured by participation throughout the Audit Period, which saw several suppliers offering multiple RFPs, and several winning

suppliers. Evidence suggested NSPI negotiated with winning suppliers in good faith, meaning that NSPI generally honored the conditions of each winning bid, while still holding bidders to their promises in those bids. The RFP evaluation methodology is also reasonable, as it focuses on price, and considers transportation costs, quality adjustments, and environmental adjustments and limitations. The RFPs also consider counterparty risk, such as credit and country risk.

Conclusion IV-9: NSPI used a mix of RFPs, bilateral canvassing of the market for offers, and bilateral negotiations for solid fuel supply and related services.

Conclusion IV-10: NSPI's process for vetting proposed procurement transactions through the FST via detailed memos and/or presentations on ERM's recommended approach is robust, establishes the "need" for any proposed transactions, considers competitive alternatives, and was consistently applied throughout the Audit Period. Documentation of this process was also effective, including use of Record of Procurement Approval documentation and maintenance of the Fuels Data Cart.

Conclusion IV-11: We observed no violations of Fuel Manual guidelines during the Audit Period.

Conclusion IV-12: NSPI's decision-making regarding the May 2024 mid-sulfur coal RFP was sound. The RFP resulted in supply contract with [REDACTED] and [REDACTED] that matched the RFP offers as evaluated. The total estimated value of the contracts was \$ [REDACTED]

Conclusion IV-13: The [REDACTED] mine remained closed throughout the Audit Period. NSPI was subject to a contract with [REDACTED] the operator of the [REDACTED] Mine, for [REDACTED] coal, but only to the extent that any coal was mined during the contract period. That contract expired at the end of 2024 and there was no further mined coal from [REDACTED] or deliveries of [REDACTED] coal to NSPI. As of the end of the Audit Period, NSPI has no outstanding or unresolved contractual obligations related to the [REDACTED] Mine.

Conclusion IV-14: NSPI's decision-making regarding the June 2024 LSH coal RFP was reasonable, including the [REDACTED] contract (which matched the RFP offer) and [REDACTED] optional cargoes. As was the case in multiple RFPs during the Audit Period, NSPI received offers for supply that NSPI's subject matter experts recommended against consuming in NSPI's fleet.

Conclusion IV-15: Regarding NSPI's October 2024 low-sulfur coal RFP, NSPI selected the lowest cost offer for LSH coal [REDACTED] in lieu of the lowest cost offer of LSL fuels, resulting in an incremental cost of \$ [REDACTED] USD. NSPI's reasoning for this decision was that LSH coal provides additional, unquantified benefits in maximizing generating unit output through better heat content and flexibility in fuel blending. This is a valid rationale. Given the unquantifiability of the "flexibility" benefit of the LSH coal, we are unable to verify that the value of LSH coal relative to LSL coal is sufficient to cover the incremental price of [REDACTED] USD.

Conclusion IV-16: Further in regards to the October 2024 low-sulfur coal RFP, the selection of [REDACTED] subjected NSPI to a material increase in "country," "supplier," and "mine" risk exposure beyond

Fuel Manual guidelines, but that NSPI followed the dictates of its Fuel Manual and determined to exceed its stated risk thresholds based on a reasonable rationale.

Conclusion IV-17: NSPI purchased an incremental cargo of LSH in the fourth quarter of 2024 for USD [REDACTED] due to the impact of an extended LIL outage in August and September and an unanticipated outage at New Brunswick's Point Lepreau plant, which limited NSPI's ability to import energy over the New Brunswick tie. NSPI's decision was reasonable, but this incident underscores NSPI's reliance on its neighbors, and if outages or other constraints occur in New Brunswick and/or Newfoundland and Labrador, NSPI may need to incur incremental costs or, at minimum, accelerate certain purchases and costs.

Conclusion IV-18: NSPI's decision-making regarding two separate offers of remaining [REDACTED] coal supply was reasonable, forgoing an initial, higher-priced offer for unwashed [REDACTED] coal, and then later agreeing to a lower price for washed coal that compared favorably to alternative coal supplies.

Conclusion IV-19: NSPI's decision-making regarding low-sulfur, mid-sulfur coal, and petcoke supply in the wake of receiving the sulfur emissions CoV was reasonable, including use of competition (through RFPs for all three fuels) and bilateral requests (e.g., to defer [REDACTED] deliveries) to make these purchases efficiently.

Conclusion IV-20: NSPI uses current index futures prices to evaluate index-priced solid fuel supply offers and does not add a risk premium associated with those bids when evaluating them against fixed-priced offers. This is a reasonable approach and NSPI should continue to allow suppliers flexibility in making offers, including index-priced offers. Still, an index-priced bid is subject to change and could get more or less expensive if the index price rises. NSPI hedges its [REDACTED] index exposure through derivative contracts, which is a credible way to reduce exposure to index price variations, but hedging has costs and is subject to risk of unexecuted hedges due to market price movements as the hedging procurement process takes its course. We include a recommendation that NSPI consider a method to account for index price risk when evaluating index priced offers against fixed price alternatives, without sacrificing the benefits of allowing suppliers to offer index-priced bids. **(Recommendation IV-1)**

Conclusion IV-21: The results of NSPI's October 2025 petcoke RFP were reasonable, though did result in a suboptimal contract clause. As offered, winning supplier [REDACTED] would deliver its supply between "December 1, 2025 and December 31, 2026," with the delivery schedule to be "mutually agreed upon between Buyer and Seller." In the final executed contract, the delivery schedule made no reference to the as-bid delivery period, only noting that [REDACTED] would propose a planned delivery date by December 31, 2025 and that NSPI would use commercially reasonable efforts to accommodate the schedule. This open-ended delivery schedule language is suboptimal and should be avoided in future supply agreements. **(Recommendation IV-2)**

Conclusion IV-22: During the Audit Period, circumstances led NSPI to contract with two trucking companies to transport coal from the Point Tupper Marine Terminal area (including adjacent Bear Head) to Trenton. In total, close to 75,000 tonnes of coal were trucked at a cost of approximately [REDACTED] or [REDACTED]. These \$/tonne trucking costs are about [REDACTED].

Conclusion IV-23: NSPI's decision-making regarding trucking services were reasonable in all cases but two.

Conclusion IV-24: First, NSPI failed to invite all relevant suppliers to participate in its October 2024 trucking RFP, including [REDACTED] the economic bidder in the December 2023 trucking RFP. This is a material lapse in practice from a team that ordinarily maximizes use of competition and good practices. It cannot be known what would have occurred in the RFP process had others been invited, though note [REDACTED] price offer was lower than [REDACTED] in all trucking RFPs held during the Audit Period. (We include a recommendation to reduce the likelihood of such lapses in the future.) This led to the selection of [REDACTED] which underperformed both in delivering required volumes and in meeting safety standards. However, our review of inventory data suggests [REDACTED] underperformance had no direct incremental costs to FAM customers. Moreover, once the [REDACTED] contract was awarded pursuant to the October 2024 RFP, NSPI acted prudently by (1) tracking [REDACTED] performance under the contract, (2) issuing a supplemental trucking RFP quickly upon observing [REDACTED] poor performance, (3) administering the supplemental RFP in a reasonable manner and selecting the most economic offer, (4) terminating [REDACTED] contract upon repeated safety violations, (5) allowing [REDACTED] to provide a safety mitigation plan and executing a new, lower risk contract with [REDACTED] (which again, was lower cost than [REDACTED] and (6) maximizing the volumes delivered by [REDACTED] (~39,000 tonnes vs. a contract maximum of 40,000 tonnes), not [REDACTED] (11,714 tonnes). We therefore do not recommend any disallowances associated with these contracts. **(Recommendation IV-3)**

Conclusion IV-25: Trucking needs between PTMT and Trenton may persist, particularly if Trenton 5's seasonal layup period ends earlier than forecasted.

Conclusion IV-26: NSPI's decisions to scrap 53 [REDACTED] railcars for USD \$ [REDACTED] was reasonable and based on [REDACTED] condition assessment. NSPI mitigated the cost of this option by scrapping cars to [REDACTED] on January 19, 2026.

Conclusion IV-27: The selection of [REDACTED] in the railcar RFP was reasonable and the product of a competitive solicitation. NSPI's decision to pursue a trial period to ensure the suitability of aluminum cars was reasonable and had a fairly minor incremental cost [REDACTED] plus the four-month [REDACTED] extension of \$ [REDACTED] [REDACTED]). The trial period itself was short (just a few days for some cars) and did not include winter conditions, but was at least conducted and documented. NSPI recognized the risks of winter usage of the aluminum railcars, including the vulnerability of the aluminum cars to use of Trenton's "slicer," which is a mechanical apparatus that helps break up frozen coal to allow it to be released from train cars into Trenton's hopper. (NSPI purchased a new slicer during the Audit Period at a

cost of \$ [REDACTED] (a non-FAM cost), and reported no concerns or problems with the use of the slicer with the aluminum cars.) The decision to finalize a long-term lease [REDACTED] at the end of the trial period was also reasonable.

Conclusion IV-28: NSPI's contracting methods with [REDACTED] and [REDACTED] were suboptimal. NSPI did not formally execute a four-month lease extension with [REDACTED] and its leases with Progress did not fully match the terms of the ROAs. It is reasonable and in fact encouraged for NSPI to negotiate and achieve better contractual terms following ROA development and approval, and NSPI's ability to secure a zero-dollar lease rate for the trial period was a substantially positive outcome. However, key terms, including mobilization costs, were not documented.

Conclusion IV-29: NSPI's decisions regarding rail line maintenance, including its decision to fund track maintenance on the coal spur (despite no contractual obligation to do so), were reasonable and supported by credible evidence. Costs incurred matched work purchase orders with vendors. However, NSPI's reliance on Purchase Orders (as opposed to contracts) for its \$ [REDACTED] in [REDACTED] transactions is an outlier from NSPI's normal and common practice for its suppliers of FAM-related products and services. The Purchase Orders contain key protections for NSPI and their customers and incorporate "NSPI Standard Terms and Conditions," which are appended to the Purchase Orders. However, these "standard" terms and conditions make specific references to the purchase order itself, anticipating that key details of a transaction will be specified there. In the case of the [REDACTED] Purchase Orders, there was not always a reference to key aspects of the work, such as its timing or full scope. This can subject NSPI and FAM customers to additional risk. We include a recommendation that NSPI institute a process to ensure that Purchase Orders include key information that is required in NSPI's Standard Terms and Conditions. **(Recommendation IV-4)**

Conclusion IV-30: NSPI executed several reasonable agreements for the provision of certain solid fuel services, including ocean freight shipping, rail transport, stevedoring and fuel handling services, coal loading inspection services, limestone quarry services, and ash haulage services, appropriately using RFPs in most cases to drive competitive outcomes.

Conclusion IV-31: NSPI fully addressed our prior audit recommendation related to Solid Fuel Procurement.

IV.D. Recommendations

Recommendation IV-1: NSPI should consider a method to account for index price risk when evaluating index priced offers against fixed price alternatives in its solid fuel procurement process, without sacrificing the benefits of allowing suppliers to offer index-priced bids.

Recommendation IV-2: NSPI should take steps to ensure fuel supply contracts have specified delivery periods, and that those periods match offers received from suppliers, unless in allowing for flexibility in

contract language specifying delivery periods and terms, NSPI receives compensation through other more favorable rates, terms, or conditions within the negotiated final supply agreement.

Recommendation IV-3: NSPI should introduce a process to ensure all suitable vendors are invited to relevant RFPs.

Recommendation IV-4: NSPI should institute a process to ensure that Purchase Orders include key information that is required in NSPI's Standard Terms and Conditions.

V. Solid Fuel Supply Management

V.A. Background

Effectively procuring solid fuel is one of two parts of a utility's effective approach to burning solid fuel for electricity generation. In this chapter, we review and assess the other essential part of this process—management of the solid fuel supply. We begin by looking at how solid fuel arrives at NSPI's assets and how NSPI tracks this information. We then assess NSPI's processes for weighing, sampling, and analyzing solid fuel that it has purchased. Next, we consider NSPI's approach and effectiveness of solid fuel contract administration. We then review NSPI's solid fuel suppliers' compliance with NSPI's contract terms over the Audit Period. We then review and assess NSPI's solid fuel inventories. We also review NSPI's approach to and results of physical inventory measurements and adjustments during the Audit Period.

V.B. Findings

V.B.1. NSPI's Process for Solid Fuel Receipt Information

V.B.1.a. Process

NSPI's processes remain the same as in recent audit periods. NSPI continues to use Aligné Fuels, an off-the-shelf database software owned by Fidelity National Information Services, as its transactional backbone in tracking its solid fuel. Aligné allows NSPI to reconcile the entire solid fuel supply chain, including solid fuel contract data, solid fuel received, solid fuel burned, solid fuel testing and results, and solid fuel transportation, in a single database. Aligné interacts directly with other NSPI programs—such as Oracle, NSPI's billing software—thus reducing the likelihood of errors across the long chain of solid fuel management, from contract origination all the way to billing of FAM customers.

On April 25, 2025, Aligné became unavailable due to the cyber event. It would remain unavailable until October 30, 2025, at which point it became available to a limited number of users to allow for testing of Aligné and backfilling of data recorded since April 25, 2025 into Aligné. On November 24, 2025, Aligné became available to more users, but as of the end of the Audit Period, Aligné was still in the process of being backfilled, and NSPI did not anticipate relying fully on Aligné Fuels until the end of the second quarter of 2026. The cyber event did not impact Aligné's historical database (pre-April 25, 2025 data), which was housed on off-site servers.

NSPI receives its imports of solid fuel on marine vessels at two ports: the International Pier in Sydney and the Point Tupper Marine Terminal in Port Hawkesbury. These two piers, both of which are owned by

NSPI, represent the two major hubs of coal and petcoke shipments for NSPI's fleet, with Sydney serving the Lingan and Point Aconi plants and Point Tupper serving the co-located Point Tupper unit as well as the Trenton units. Shipments from Colombia generally take about ten days to reach Nova Scotia; shipments from the US Gulf Coast take about nine days, while shipments from Baltimore take about four days.

NSPI contracted with [REDACTED] to operate the International Pier, which includes the handling, storage, warehousing, reclaiming, loading into railcars and trucks, operating the railway (to Lingan), and delivery of solid fuel from the International Pier to both Lingan and Point Aconi. NSPI also contracts with [REDACTED] to operate the Point Tupper Marine Terminal, which includes receiving shipments, unloading, handling, storage, reclaiming, loading railcars (for Trenton), loading reclaim hoppers at Point Tupper, and transporting solid fuel to Bear Head (a storage area near the port), among other services. NSPI also [REDACTED] for storage and reclaiming of solid fuel at the [REDACTED] which is located adjacent to the International Pier.²²⁹ As we explain in Chapter 4, NSPI also contracted with multiple vendors to provide coal trucking services from the Point Tupper Marine Terminal to Trenton.

NSPI also purchased a small amount of domestic coal during the Audit Period from the owner of the [REDACTED] Mine. The Donkin coal was purchased from the supplier's inventory location, as no new [REDACTED] coal was mined or provided to NSPI during the Audit Period. NSPI also received no coal from the Stellarton Mine, which ceased operations prior to the Audit Period. Domestic solid fuel is purchased on an as-delivered basis and is trucked to NSPI's plants.

When imported solid fuel is received from an ocean-going vessel, it is offloaded into solid fuel piles at either International Pier or the Point Tupper Marine Terminal. Upon transfer of coal ownership to NSPI, the quantity and costs associated with that solid fuel become part of the quantity and weighted average cost of that pile. The solid fuel in those piles is then moved to the generating plants as required. When solid fuel is moved from an offloading facility to the generating plants, the quantity and weighted average cost of the solid fuel at the time are transferred to the plant, modifying the quantity and weighted average cost of the corresponding solid fuel pile located at the generating plant that was received from prior deliveries.

Regarding NSPI personnel responsibilities, ERM is responsible for determining solid fuel requirements, procuring solid fuel, entering into solid fuel purchase transactions, undertaking the corresponding fuel supply contract administration, managing the marine receiving ports (including the receipt of solid fuel, i.e., unloading of marine vessels), tracking the fuel quantity and quality received, and delivering the solid fuel to the individual generating plants. Individual plant personnel are responsible for receiving the fuel onto their site (e.g., unloading of rail cars) and maintaining the fuel stockpiles.

²²⁹ "HLS - 20240119 3rd Amendment."

Solid fuel imported shipments are tracked via an Excel spreadsheet called the Vessel Schedule. The Coal Procurement and Logistics Specialist is responsible for managing and maintaining the Vessel Schedule on the Fuels SharePoint site. Delivery can be, at NSPI's option, to either the Point Tupper Marine Terminal or International Pier. The Coal Procurement and Logistics Specialist develops the scheduling of vessels via the Coal Inventory Model approximately four months prior to the beginning of each calendar year. The applicable quarterly forecast for the upcoming year is used to establish when tentative shipments should be scheduled, based on the forecast quantities by commodity by plant. The Coal Procurement and Logistics Specialist uses the Coal Inventory Model to schedule shipments [REDACTED] [REDACTED] by commodity into both International Pier and Point Tupper Marine Terminal throughout most of the year, with the exception of late third quarter through the end of the year, when shipments escalate for winter readiness. Once tentative shipment periods are identified, the Vessel Schedule development begins by linking all shipments to existing contracts against tentative loading periods. The Vessel Schedule includes pertinent tracking details for each NSPI coal and petcoke shipment, such as shipper, supplier, load date, disport date, load port, country of origin, year of schedule, status of shipment (i.e., confirmed/not confirmed), and link to appropriate contract date. The Coal Procurement and Logistics Specialist uses this Vessel Schedule to provide guidance to both solid fuel suppliers and CSL International on NSPI's shipment requirements throughout the year. The Logistics Administrator then uses the Vessel Schedule to link each shipment to its appropriate contract and enter into Aligne for purchase order generation and shipment tracking of vessels.

For transport to NSPI's five coal generating stations (Lingan, Point Aconi, Point Tupper, Trenton 5, and Trenton 6), the Senior Contract Administrator of ERM is involved in daily and weekly monitoring and delivery of coal and petcoke to each facility. The Senior Contract Administrator uses and updates an Excel spreadsheet to track the estimated arrival times of projected vessel deliveries by coal type arriving at NSPI's two terminals. The spreadsheet also tracks the deliveries by domestic fuel suppliers, the current site inventories (tonnes by coal type), and the projected deliveries (tonnes by coal type) for each generating facility, which is netted off against the projected consumption of each coal type. The Senior Contract Administrator discusses the planned deliveries with each generating facility to determine if deliveries need to be altered in reaction to any operational or inventory situations that may have arisen. Weekly conference calls are also conducted with the generating facility operators or coal handling personnel to discuss the vessel arrivals and the fuel's subsequent transport in addition to a verification of current inventory levels at each site. The Senior Contract Administrator communicates daily with NSPI's terminal operators to discuss upcoming vessel arrivals and unloading and stockpiling efforts for all coal and petcoke received. The Senior Contract Administrator regularly communicates with the Coal Procurement and Logistics Specialist to discuss any inventory constraints that may require action, e.g., rescheduling a shipment or a blend change.

During the April 25, 2025 to December 31, 2025 period, the process for tracking and recording deliveries of solid fuel was done outside of Aligne. Contract quantities and qualities were verified under normal operating procedures, as Aligne has no material role in the quality assurance process. However, as

deliveries were received, instead of entering delivery information directly into Aligné, which would then feed to Fuels Finance and the Oracle system, NSPI implemented spreadsheet-based tracking mechanisms for both vessel-related deliveries and for solid fuel arriving by truck and rail at the plants themselves. To do this, NSPI began with the known inventory quantities at each inventory location at the time of Aligné becoming unavailable. NSPI then added deliveries to those inventory amounts, using vessel schedules and bills of lading for vessel deliveries and delivery data from the plants for truck and rail deliveries. Consumption of solid fuels was provided by the plants, which continued to be tracked through either the Process Information (“PI”) system or through the plants’ distributed control systems (“DCS”), including SCADA, which continued to run and was unaffected by the cyber event. Plant personnel provided consumption data to the Fuels team, which updated the Excel-based tracking mechanism for each inventory location.

V.B.1.b. FAM Cost of Point Tupper Marine Terminal, International Pier and Capital Projects

All fuel handling costs at the International Pier and Point Tupper Marine Terminal are recovered through the FAM. During the Audit Period, FAM-recoverable fuel handling costs at the International Pier totaled \$7.7 million in the Audit Period. This was a decrease of about 67 percent as compared to the prior Audit Period’s costs (\$23.2 million). At the Point Tupper Marine Terminal, fuel handling costs totaled \$3.9 million. This was a decrease of about 42 percent as compared to the prior Audit Period’s costs (\$6.7 million).

NSPI owns both the International Pier and the Point Tupper Marine Terminal and thus is responsible for capital expenditures associated with both terminals. Capital expenditures related to the two terminals are not recovered through FAM but through the fixed cost recovery portion of rates. Total capital expenditure at the International Pier totaled \$6.8 million during the Audit Period, up from \$2.2 million in the prior Audit Period. Capital expenditures at Point Tupper Marine Terminal were \$4.5 million, up from \$2.0 million in the prior Audit Period.

NSPI undertook several studies during the Audit Period which have implications for the Point Tupper Marine Terminal (and Bear Head site) and the International Pier. While these reports did not directly impact FAM costs during the Audit Period, they are indicative of the condition of these assets and may portend future capital costs, which can have an impact on FAM costs. We provide brief summaries of those studies here.

On September 29, 2025, [REDACTED] provided an inspection report for the Point Tupper Marine Terminal, concluding that “[t]he majority of the structure is in good to fair condition and only minor repairs are required.” Two “significant” items were identified: “load rating of the steel pipe pile for the trestle towers,” which “are in fair to serious condition due to the loss of section in the piles,” and “repair or replacement of the main load carrying channels for the small boat wharf.” NSPI commissioned and received a separate inspection report of the mooring bollards at Point Tupper Marine Terminal from [REDACTED] on September 30, 2025, with all ten mooring bollards receiving a “pass” rating.

On April 30, 2024, [REDACTED] provided a report estimating the cost associated with “stabilizing” the “E-Crane” at the Point Tupper Marine Terminal, a 424-ton mechanical apparatus located on the pier of the Point Tupper Marine Terminal that is used to offload solid fuel from vessels docked at the pier. The E-Crane was installed in 2005 [REDACTED]. Over time, self-unloading vessels have proliferated, reducing their premium, which has reduced the usage of the E-Crane. NSPI commissioned the study from [REDACTED] due to concern with “environmental risk and long-term maintenance costs” of the E-Crane given its “limited use” and following a 2022 “hydraulic hose failure” which “highlighted the deteriorated condition of the E-Crane hydraulic system.” In the Fall of 2022, the E-Crane was “decoupled from the coal receiving hopper and parked at the inhaul conveyer end of the wharf, with all power...disconnected, but all hydraulic components left as is.” [REDACTED] assessed the cost to “de-energize and drain the hydraulic systems” and “structurally stabilize the E-Crane on the wharf for the future,” which was one of the options [REDACTED] identified in a 2022 report. [REDACTED] estimate for this work was \$2,078,000. In December 2024, [REDACTED] provided an additional report that would “outline the recommendation to leave the E-Crane parked in its current position,” which was a departure from the 2022 and 2024 [REDACTED] reports which “were based on moving the E-Crane closer to the Inhaul Conveyor and lashing the stick to the deck of the wharf.” [REDACTED] December 2024 report recommended draining hydraulic oil and implementing monthly inspections, among other recommendations.

At the Bear Head site, NSPI commissioned a study by [REDACTED] to provide a cost estimate for upgrades to the coal storage area of Bear Head. The total project cost estimate was \$654,663.95. Work at Bear Head focused on improving drainage, which included regrading, installation of new spillways and culverts (and removal of others), and installation of riprap around the coal piles.

On January 17, 2025, Stantec provided an inspection report for the International Pier, concluding that “[t]he majority of the structure is in good to fair condition and only requiring minor repairs.” Two “significant” items were identified: “a load evaluation and material testing of the piles” that “support the slews railing,” which “are in poor to serious condition,” and “replacement of the nuts and washers connecting the walkway to the piers caps” since “the nuts holding the walkway to the slews rail pipe caps are in critical condition.”

Another project assessed at the International Pier was related to the settling pond system at the site, which manages water runoff through a series of concrete ditches directed to settling ponds which remove the coal fines before the water is “discharge[d] into the environment.” [REDACTED] provided a 2022 design report to NSPI which redesigned the settling pond system to increase the water quality of the discharged water, but the “prohibitive costs” led NSPI to request [REDACTED] to provide a report that identifies “next steps” to “improve the performance (settlement of coal fines prior to discharge) of the settling ponds.” [REDACTED] produced the “next steps” report on March 7, 2025, noting that “[t]he current settling ponds have insufficient volume to adequately settle out coal fines, particularly during heavy rain events.” [REDACTED]

identified a series of discharge structure upgrades and installation of an “experimental slag berm,” which increase water quality by increasing the retention time of the water in the pond and physically filtering coal fines from the pond water. The estimated cost of this project was \$628,692.35. [REDACTED] concluded that these “‘next steps’ should improve pond performance but may not be entirely sufficient to ensure discharge quality permit requirements are met,” and that “an increase in pond size, and diversion of off-site runoff, would be required” to “properly handle the water on site.”

One final study commissioned by NSPI involved a “Structural Assessment Report” of the Sydney Coal Railway Bridge by [REDACTED] in consultation with [REDACTED]. The November 2025 report assessed the structural adequacy, load-carrying capacity, and fatigue performance of the 34-foot, single span, open deck plate girder railway bridge located at milepost 10.10 on the Sydney Coal Railway. The bridge is owned and operated by NSPI and was “likely constructed in the 1940s.” The report found “severe corrosion damage,” “non-uniform load distribution” that “increases internal stresses,” and “inner girders [that] are unsafe under both fatigue stresses and section strength.” [REDACTED] recommended replacing all girders and adjusting the alignment of the girders or the position of the track to achieve a more uniform load distribution.

V.B.2. Quantity and Quality Control of Solid Fuel

NSPI’s solid fuel supply contracts contain quantity and quality technical specifications that suppliers must meet in providing solid fuel and related services. Determining whether the solid fuel meets those specifications is a crucial aspect of solid fuel supply management. For NSPI, this is not a simple task; much of its solid fuel is imported internationally, meaning that it must find ways to ensure adequate quantity and quality of its shipments, despite the distance between NSPI and the solid fuel sources on which it relies. This section explains the adequate processes NSPI has in place for testing the quantity and quality of its solid fuel supply, which are contained in NSPI’s Fuel Manual. As we explain below, NSPI has quality control in place both at the loading ports, the receiving ports, as well as at NSPI’s generating plants.

V.B.2.a. Imported Solid Fuel

Consistent with the prior audit period, and as per the Fuel Manual, NSPI has engaged independent load port representatives acting on NSPI’s behalf to witness the loading and sampling of each vessel at the load ports to ensure that established ASTM procedures are being followed for the collection of the transactional sample. [REDACTED] serves NSPI as its load port representative and provides a series of services related to NSPI solid fuel shipments at the loading port, including inspection of the cargo holds and condition of the vessel, observation of the coal loading operation, review of belt

scale calibrations, and verification of the quantity of water added to the shipment for dust control.²³⁰ CESI offers its services at 22 ports, including those used by NSPI in Colombia and in the United States.²³¹

██████ oversees that the transactional sample is split and analyzed by two other independent labs (one commissioned by the load port representative and one local lab commissioned by NSPI—i.e., ██████²³²). NSPI selects these samples annually for analysis by ██████ and does not allow the unloading of cargoes to commence unless it has received the transactional analysis of the cargo from the supplier and has confirmed that this analysis is in compliance with the quality specifications in the purchase agreement. NSPI logs the disport terminal belt scale readings on each cargo unloading and compares it to the transactional draft survey. These analyses are in addition to the transactional analysis that the supplier's lab carries out. Draft surveys are conducted by an independent third party contracted by the supplier; these draft surveys determine the cargo quantity and, consistent with the Fuel Manual,²³³ it is this quantity determined by the draft survey that is recorded on the Bill of Lading.

Once this process is complete, the Coal Procurement and Logistics Specialist receives invoices via email and/or by courier and receives the report from the supplier's independent lab and the draft survey. ██████ also sends a report that verifies the draft survey result and that proper procedures were followed in loading the vessel. The Bill of Lading, which contains the draft survey result, is endorsed by the authorized vessel representative. The NSPI Logistics Administrator uses the draft survey information from the Bill of Lading to enter the shipment volume into Align. During the aftermath of the cyber event, NSPI used Excel-based trackers to track fuel quantity and quality.

Upon the coal's arrival at either the International Pier or the Point Tupper Marine Terminal, NSPI verifies the transactional data related to the shipment to the contract specifications; if there is a concern, NSPI is not obligated to accept the shipment.²³⁴ In some cases, NSPI has rejection rights, but more often than not will negotiate a price adjustment under the contract. In any event, in these cases, NSPI is not responsible for demurrage costs under its coal supply agreements that are related to delays caused by such deviations from contracted technical specifications. If the supplier exceeds contractual limits for "laytime," or the time it takes to load a vessel, NSPI is entitled to demurrage payments,²³⁵ an important protection that provides suppliers and shippers incentive to deliver the quantity and quality of solid fuel found in the technical specifications of the contract. NSPI's contractor weighs the coal using a belt scale

²³⁰ "CESI - 20240501 Cargo Experts Survey Inspections - NSPI - Services Agreement 6521.9765," Schedule A.

²³¹ "CESI - 20240501 Cargo Experts Survey Inspections - NSPI - Services Agreement 6521.9765," Schedule A.

²³² NSPI Fuel Manual Version 14, Link 9, "Solid Fuel Procurement Quality Assurance for Sampling and Analysis."

²³³ NSPI Fuel Manual Version 14, Link 9, "Solid Fuel Procurement Quality Assurance for Sampling and Analysis."

²³⁴ See, for example, "Consol - 20240711 Coal Supply Agreement," section 9.

²³⁵ See, for example, "Javelin - 20151008 Master Coal Supply Agreement - Javelin Global Commodities and NSPI," section 12.14.

on the in-haul conveyor from the dock and then provides NSPI with a report. The contractor is required to calibrate the scales when necessary.²³⁶

Solid Fuel invoices are received against the purchase orders approved and set up by ERM. Oracle is configured so that fuel purchases are accrued upon receipt if matched to a purchase order. Activities against a shipment that result in charges being posted will automatically post transactions to the inventory and payable ledgers in Aligne, as well as generate the general ledger transactions for the appropriate accounts through the month-end interface between Aligne and Oracle. Again, during the aftermath of the cyber event, NSPI used Excel-based workarounds to manage the loss of access to Aligne and Oracle.

V.B.2.b. Domestic Solid Fuel

As explained in Chapter IV, NSPI received just a small volume of domestic coal (7,987 tonnes) during the Audit Period. This Donkin coal was delivered to Langan. At Langan, under NSPI's contract with [REDACTED] Donkin coal delivered to NSPI was sampled by [REDACTED] for comparison to contractual technical specifications.²³⁷

V.B.2.c. Quality and Quantity Control at NSPI's Plants

With the exception of Point Tupper, NSPI's plants have certified truck scales that weigh the incoming deliveries. Imported supply for the Trenton units arrive by rail and is weighed at the Point Tupper Marine Terminal. Plant personnel verify the arrival of the railcars in each delivery, entering the information manually into Aligne (and during the cyber event, manually into an Excel-based tracker). A similar approach is taken at Langan for solid fuel arriving by rail.

The plants have various feeders, meters, and measurement systems to determine the accurate quantity of solid fuel entering the plant for combustion. The measurements taken by the feeders/meters occur as solid fuel is consumed. Measurement equipment is subject to scheduled calibrations at least twice per year to ensure they are automatically fed into the PI system. The consumption information from PI is then fed into Aligne. The Operations Superintendent for each of the plants enters the solid fuel blend ratios—which continue to be provided by ERM—into Aligne. Aligne then divides the overall daily consumption as reported by PI into the various types of solid fuels based on the blend ratios specified. The Operations Superintendent reviews the calculated consumption figures in Aligne and confirms or manually adjusts if required. As part of the month-end close process, the Financial Analyst performs a reconciliation between the consumption as reported by PI and consumption recorded in Aligne, noting any variances. At month end, consumption figures are reviewed by the Manager of Fuels Accounting and Reporting for completeness and reasonability.

²³⁶ See, for example, "Savage - 20180729 INP Services Agreement," section 2.05 (g).

²³⁷ "Coalspur - 20241130 Coal Sales Confirmation," PDF page 2.

Testing of solid fuel is done frequently and both on-site (at NSPI plant labs) and by independent third parties. At Langan, for example, samples are tested three times per week at the plant laboratory for various quality metrics, including ash, Btu, and sulphur content.

V.B.3. Solid Fuel Contract Administration

NSPI's solid fuel contract administration is under the direction of the Senior Manager of Fuels Strategy and Performance. The Senior Manager's team includes the Coal Procurement and Logistics Specialist, who conducts the daily administration of international fuel contracts—i.e., overseeing contracts for shipping solid fuel supply from international mines to Nova Scotia—including regularly inputting fuel information into NSPI's vessel schedule, monitoring the status of international shipments, and monitoring the fuel shipments for quality and quantity. Senior Contract Administrators are responsible for the solid fuel supply once it reaches Nova Scotia, managing the inventory at both the International Pier and Point Tupper Marine Terminal, as well as at NSPI's generating stations. A Logistics Administrator inputs information from the vessel schedule into Align.

Both the Coal Procurement and Logistics Specialist and the Senior Contract Administrator conduct site visits throughout the year. The Coal Procurement and Logistics Specialist visits both the Point Tupper Marine Terminal and International Pier at least once annually, and also visits coal mines that supply NSPI's fuel. The Senior Contract Administrator, who maintains a primary office in the field in Sydney, Nova Scotia, regularly visits each generating station site and the two unloading port sites on an as-needed basis, and meets with its pier managers throughout the year.

NSPI's solid fuel contract administration staff regularly participate in scheduled meetings and calls that help support their administration function. These include NSPI's daily morning meetings, quarterly ERM team meetings, weekly vessel scheduling meetings, and weekly inventory meetings, which include representatives from each of NSPI's solid fuel-fired generating stations. They also participate in the Energy Control Centre's weekly outage coordination meetings which are in place to coordinate transmission and generation outages.

V.B.4. Contract Compliance

V.B.4.a. Contract Quantities

Each of NSPI's coal and petcoke contracts calls for a contract quantity, with a tolerance of some percentage that can be delivered above and below the contracted quantity. From these numbers, it is simple to determine the minimum and maximum quantities under each contract. It is important that NSPI generally observes that actual quantities delivered under its agreements fall within this minimum-maximum range, since that range represents NSPI's expected solid fuel needs. NSPI's coal supply contracts contain recourse in the event the supplier fails to meet specified quantity requirements. Failure to meet technical specifications is managed through rejection rights or forms of compensation specified in

the supply contract. It is common that in lieu of physically rejecting a vessel from unloading, NSPI will negotiate compensation prior to the vessel being permitted to unload. Failure to meet quantity requirements is managed through seller's deficiency stipulations in the supply contract and/or compensatory settlement agreements.

To test NSPI's contracted solid fuel suppliers' performance during the Audit Period, we selected five solid fuel contracts (covering four counterparties) and tested their compliance with their contractual obligations. Figure V-1 shows the results for our sample, which included: (1) [REDACTED] contract to provide mid-sulfur coal, (2) IMI Fuels' contract to provide LSH coal, (3) [REDACTED] contract to provide LSH coal, (4) [REDACTED] contract to provide LSL coal, and (5) [REDACTED] contract to provide petcoke. In all cases, NSPI's suppliers performed adequately.

Figure V-1: NSPI Solid Fuel Contract Deliveries vs. Contract Limits (Metric Tonnes)²³⁸

Supplier	Contract	Product	Quantity Received	Contract Minimum	Contract Maximum	Underdelivery
[REDACTED]	[REDACTED]	MS	304,957.00	264,600.00	323,400.00	-
[REDACTED]	[REDACTED]	LSH	335,808.79	208,800.00	510,400.00	-
[REDACTED]	[REDACTED]	LSH	55,115.41	52,200.00	63,800.00	-
[REDACTED]	[REDACTED]	LS	421,286.52	261,000.00	510,400.00	-
[REDACTED]	[REDACTED]	Petcoke	57,298.04	49,500.00	60,500.00	-

V.B.4.b. Contract Quality

NSPI's coal supply contracts contain recourse in the event the supplier fails to meet specified requirements for quality. Failure to meet technical specifications is managed through rejection rights or forms of compensation specified in the supply contract. It is common that in lieu of physically rejecting a vessel from unloading, NSPI will negotiate compensation prior to the vessel being permitted to unload. For domestic coal contracts, NSPI has delivery suspension rights as well as compensatory quality adjustments. During the Audit Period, NSPI reported no instances of suppliers of coal or petcoke failing to meet their contractual obligations for quality. (Discussion of our contractual samples follows below.)

V.B.4.c. Bates White's Contract Administration Samples

To test the contractual compliance of NSPI's solid fuel suppliers, we sampled seventeen shipments of solid fuel (coal, petcoke, additives). Specifically, we examined (1) the underlying confirmation agreement stipulating the quantities to be delivered over a given time period, (2) the quantity and quality test results for a given delivery, and (3) NSPI's data containing all pricing adjustments for quantity and quality of the delivery. All tested samples were within contractual quantity tolerances. In all cases, we confirmed that prices were calculated correctly and in line with the underlying contractual arrangements. We confirmed that in all instances, proper and accurate adjustments were made to invoiced prices and costs to be reflective of the heat content, sulfur content, and in some instances, mercury content of the solid fuel,

²³⁸ Contract minimums and maximums derived from fuel contracts.

where appropriate, with some adjustments being upward (to reflect higher quality) or downward (to reflect lower quality).

V.B.5. Solid Fuel Inventory

V.B.5.a. NSPI's Approach

NSPI's approach to solid fuel inventory management is contained in its Fuel Manual. It defines a governing principle, a series of targets that guide NSPI, and a series of thresholds that, if breached, require specific action. NSPI's approach is sufficiently specific to ensure NSPI personnel understand relevant protocols, while allowing for flexibility in managing inventory to meet specified targets.

NSPI's governing principle is to have sufficient staple fuels—i.e., primary fuels needed to support the plant's loading requirements—to meet its peak demand season, which is the winter months: January, February, and March. NSPI describes this approach as “winter readiness” and seeks to meet its inventory targets by December. This approach is appropriately codified in the Fuel Manual and includes a sufficient explanation regarding why this approach is taken: specifically, because NSPI's experience has shown that inventories can be depleted quickly when plants are running at full load and there are greater risks in the transportation of solid fuel during the winter months that could delay deliveries.²³⁹

The targets associated with winter readiness are based on operating the plants at full load, 24 hours a day, for the entire winter (i.e., 11 weeks). This historically has translated to about 700,000 and 900,000 MTs²⁴⁰ and remained the case during the Audit Period.²⁴¹ Throughout the year, and in making delivery and contracting decisions, NSPI monitors its inventory positions and looks at updated forecasts of expected consumption in building a sufficient winter-ready inventory of solid fuel.

NSPI breaks its inventory positions into two general “circuits”: the Point Tupper Circuit and the Sydney Circuit. The Point Tupper Circuit includes (1) Trenton 5's coal pile, (2) Trenton 6's coal pile, (3) the Point Tupper Marine Terminal coal piles, and (4) the Bear's Head coal storage piles located adjacent to the Point Tupper Marine Terminal. The Sydney Circuit includes (1) the Lingan coal pile, (2) the Lingan long-term “dead” storage coal pile, (3) Point Aconi's petcoke/coal pile, and (4) the International Pier coal piles. During the prior audit period, NSPI relied on short-term storage at [REDACTED] [REDACTED] for temporary storage of solid fuel during periods of inventory constraints at the International Pier and nearby thermal plants (Point Aconi, Lingan). During this Audit Period, NSPI again relied upon storage at [REDACTED] through March 31, 2024²⁴² and for purposes of our review, is part of the Sydney Circuit, located adjacent to the International Pier. **Figure V-2** shows NSPI's target inventory levels by circuit and storage pile to achieve winter readiness. Note that the actual targeted

²³⁹ NSPI Fuel Manual Revision 14, Link 7 “FERM Solid Fuel Inventory Management Process.”

²⁴⁰ 2016-2017 Bates White Audit Report, page 94.

²⁴¹ Fuel Manual Revision 14, Link 7 “Solid Fuel Inventory Management Process.”

²⁴² “HLS - 20240119 3rd Amendment.”

inventory amounts can vary due to changes in consumption forecasts. Figure V-2 provides a reasonable approximation of those targets. During this Audit Period, NSPI's overall target winter readiness solid fuel volume was between 700,000 and 900,00 metric tonnes with a target of 816,200 metric tonnes to support continuous operation for eleven consecutive weeks.

Figure V-2: NSPI's Historical Approximate Winter Readiness Inventory Targets (Metric Tonnes)

Inventory Location	Circuit	Amount	Max Physical Storage
International Pier	Sydney	0	240,000
Lingan	Sydney	385,000	500,000
Point Aconi	Sydney	115,500	96,000
Total Sydney Circuit		500,500	836,000
Point Tupper Marine Terminal	Point Tupper	0	140,000*
Point Tupper	Point Tupper	103,950	0
Bear Head	Point Tupper	0	200,000
Trenton 5	Point Tupper	96,250	85,000
Trenton 6	Point Tupper	115,500	60,000
Total Point Tupper Circuit		315,700	485,000
Total NSPI Fleetwide		816,200	1,321,000

*Point Tupper Marine Terminal (PTMT) allows maximum physical storage of 164 kt. The PTMT operating permit allows a maximum coal storage of 120 kt under the shuttle conveyor. From December 2024 through the rest of the Audit Period, NSPI set the maximum operating limit to [REDACTED] recommended 96 kt under the shuttle conveyor for day-to-day operations, and up to 120 kt, if required, subject to review and approval by the Director of ERM.

NSPI also aims to control inventories of adder fuels—i.e., inferior fuels unable to support plant loading requirements but used in blending to provide economic benefits—entering the winter months so as to not constrain coal pile building and year-end inventory targets.²⁴³

Besides these fleetwide and plant specific targets, NSPI defines minimum and maximum inventory guardrails that, if breached, trigger specific action; if levels reach as high as 13 weeks at maximum consumption or as low as 4 weeks at current consumption for a 30-day period, the Coal Procurement and Logistics Specialist is required to develop and provide a corrective plan to the Senior Manager and Director of ERM. That plan may include purchasing additional vessels of fuel (if below inventory) or maintaining current inventory levels due to economics.²⁴⁴

V.B.5.b. Audit Period Results

NSPI's actual inventories are provided in the following set of figures. Figure V-3 and Figure V-4 show solid fuel inventory, by month, at the two NSPI circuits for 2024. Figure V-5 provides NSPI's

²⁴³ NSPI Fuel Manual Revision 14, Link 7 "Solid Fuel Inventory Management Process."

²⁴⁴ NSPI Fuel Manual Revision 14, Link 7 "FERM Solid Fuel Inventory Management Process."

overall inventory amounts, by month, in 2024. References to “International Pier” also include any temporary storage at the Atlantic Canada Bulk Terminal owned by Provincial Energy Ventures.

Figure V-3: 2024 Solid Fuel Inventory at the Point Tupper Circuit (Metric Tonnes)

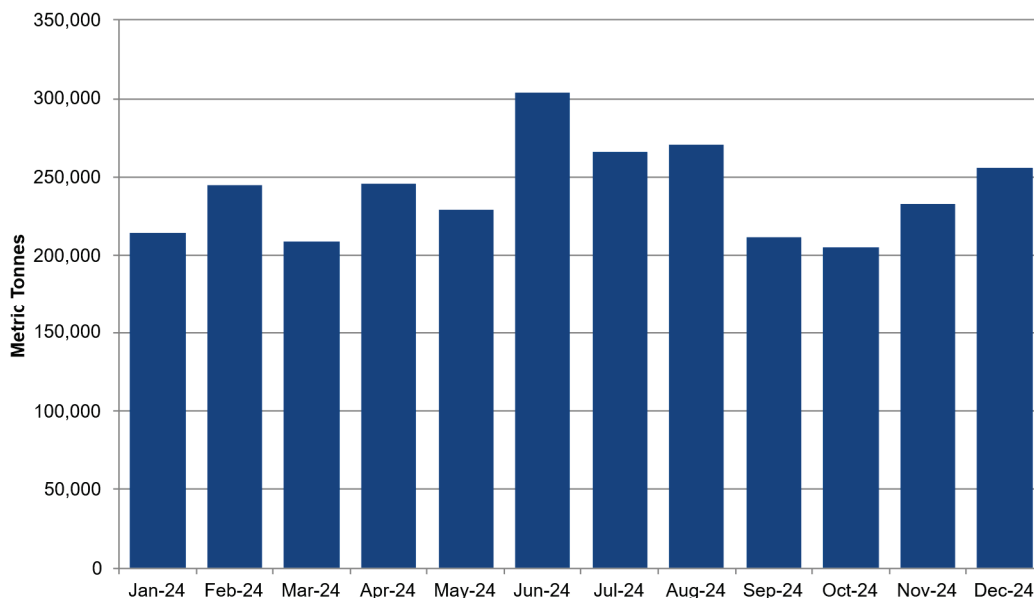


Figure V-4: 2024 Solid Fuel Inventory at the Sydney Circuit (Metric Tonnes)

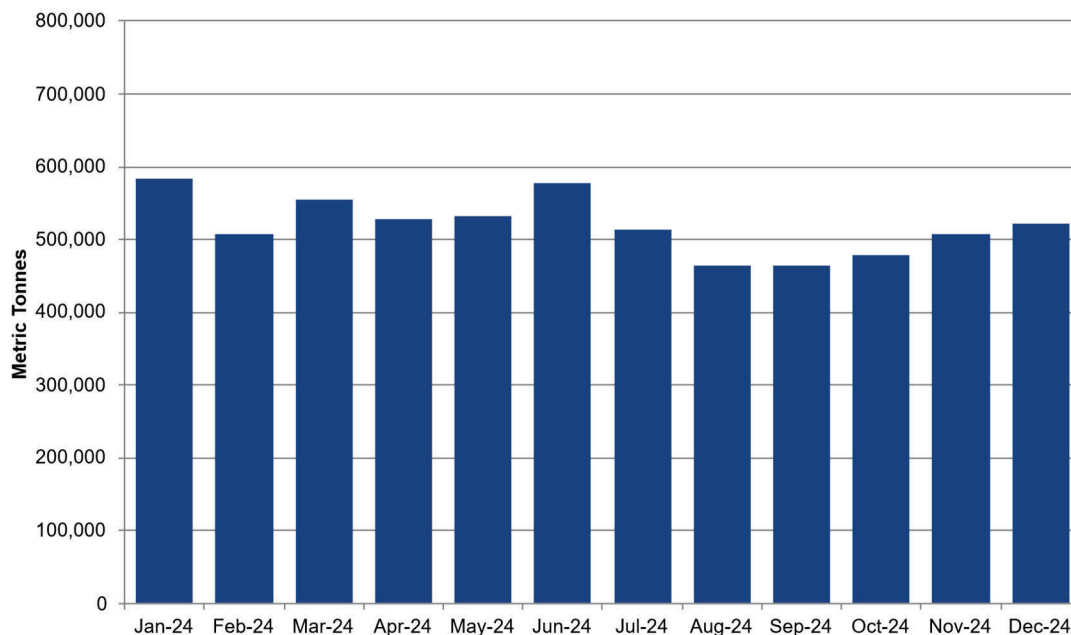
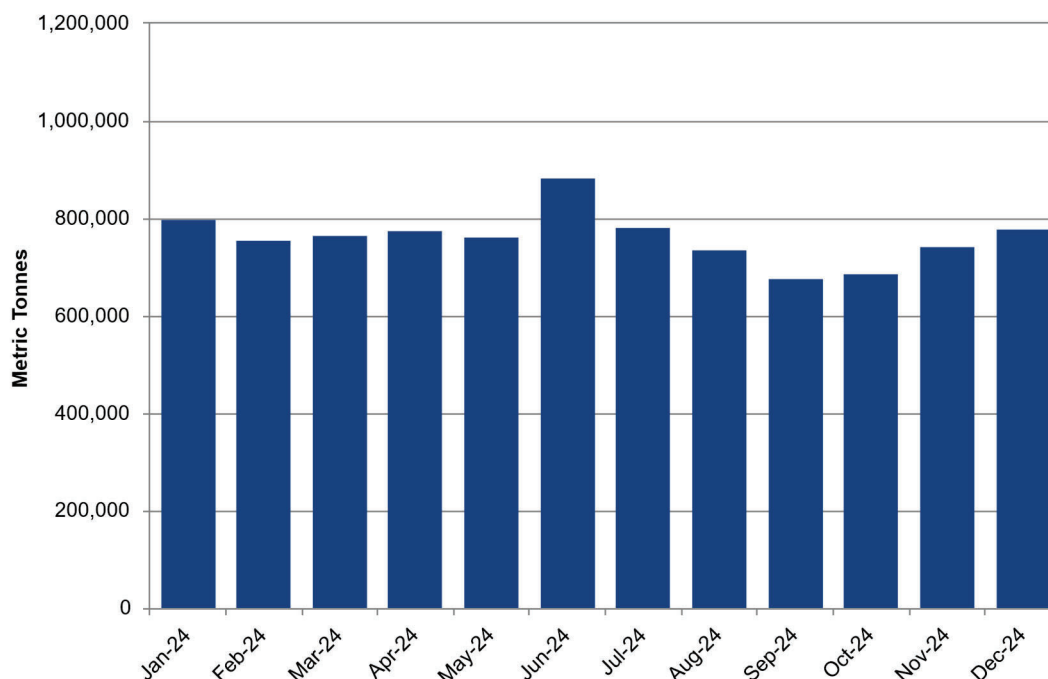


Figure V-5: 2024 NSPI Total Solid Fuel Inventory (Metric Tonnes)



As shown in the figures above, 2024 inventories were reasonably stable and within historical ranges. At Point Tupper Marine Terminal, inventories ranged from about 205,000 metric tonnes (October 2024) to approximately 303,000 metric tonnes (June 2024), while December inventory reached 256,230 metric tonnes, or 81% of its winter readiness target. Inventories at the larger Sydney circuit were materially higher, ranging between approximately 464,000 tonnes (September 2024) and 584,000 tonnes (January 2024). The Sydney circuit had 521,265 metric tonnes in December 2024, or 104% of its winter readiness target. Overall, NSPI had 777,495 metric tonnes of coal in inventory in December 2024, or 95% of its winter readiness target. NSPI did not cancel or divert any shipments of solid fuel in 2024, but NSPI was unable to indicate whether there were any deferred coal shipments in 2024 due to that data being lost in the cyber event.

NSPI reported no instances of excess inventory, nor did we observe any such instances. We note that NSPI receives a return on its solid fuel inventory equal to its approved return on equity and thus has some incentive to have higher solid fuel inventories, and we note (as we have in the past) that any negative adjustments to inventories do not require the realized returns to be adjusted after the fact. However, our review found no evidence of excess inventories in 2024.

Figure V-6 and Figure V-7 show solid fuel inventory, by month, at the two NSPI circuits for 2025. Figure V-8 provides NSPI's overall inventory amounts, by month, in 2025.

Figure V-6: 2025 Solid Fuel Inventory at the Point Tupper Circuit (Metric Tonnes)

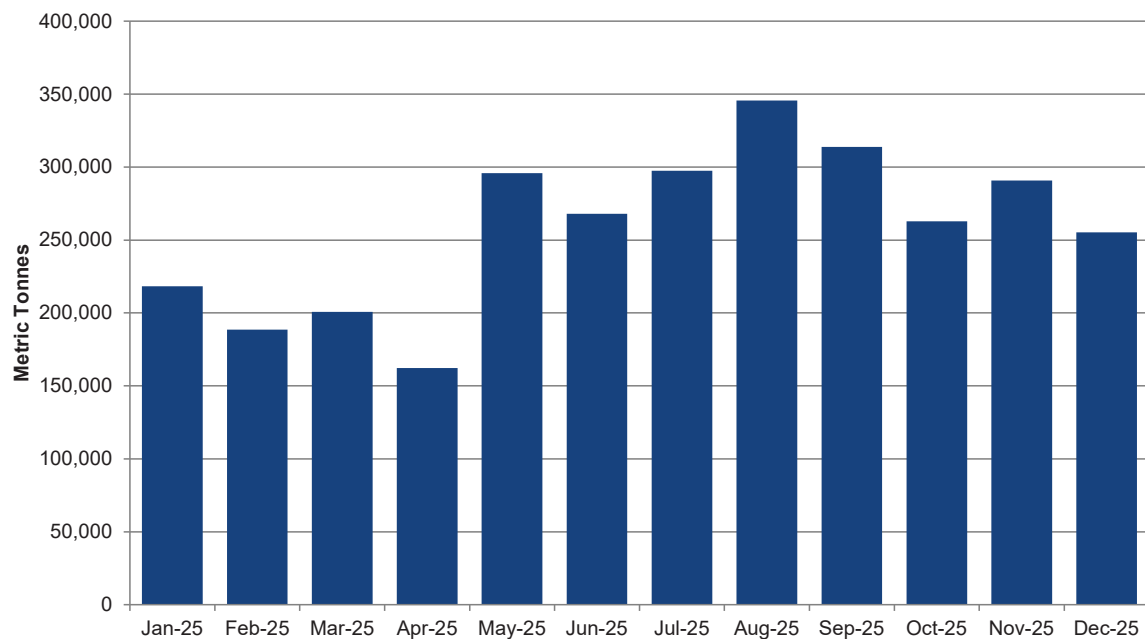


Figure V-7: 2025 Solid Fuel Inventory at the Sydney Circuit (Metric Tonnes)

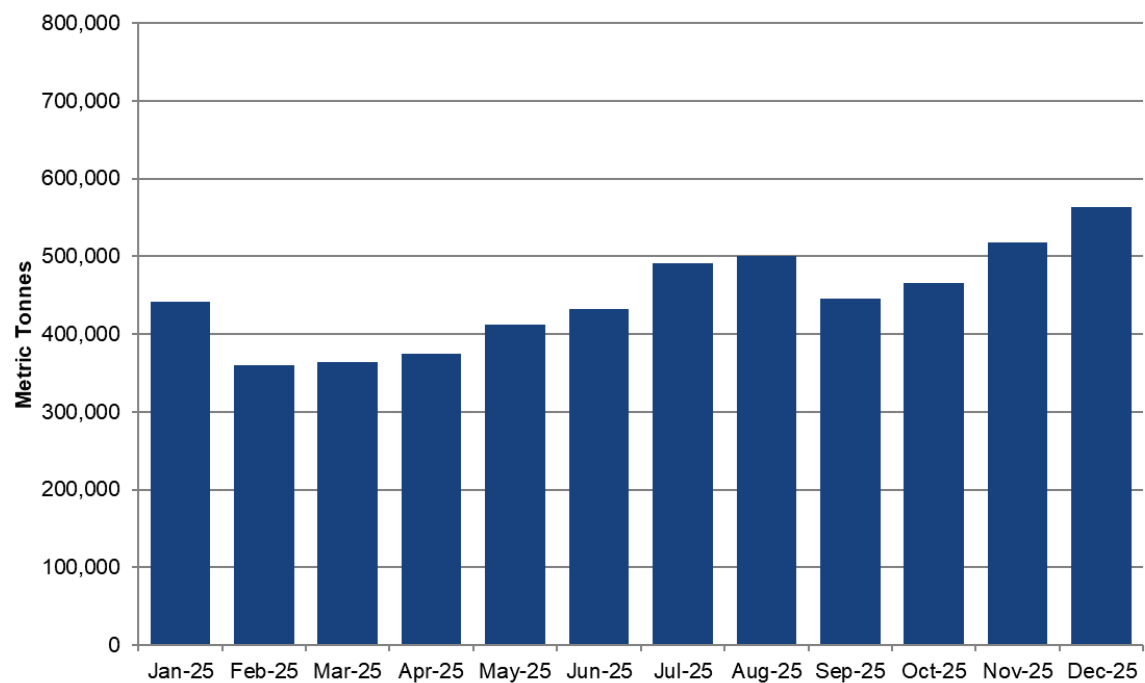
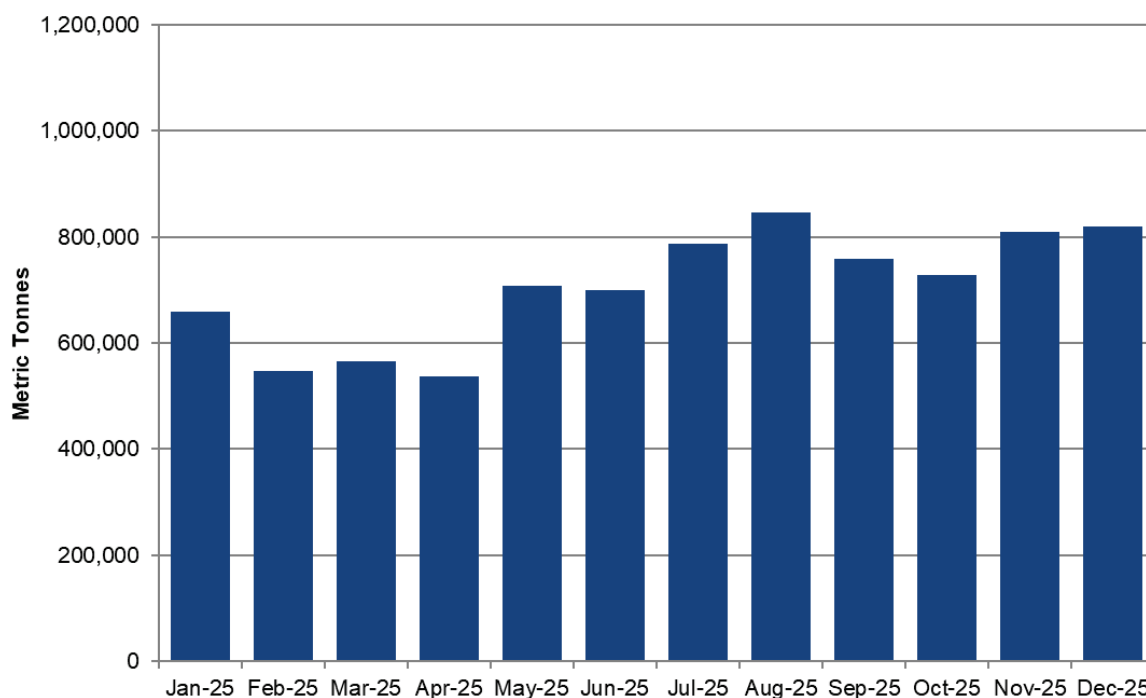


Figure V-8: 2025 NSPI Total Solid Fuel Inventory (Metric Tonnes)



The results in 2025 showed overall lower inventories than in 2024, though results varied by circuit. Point Tupper Marine Terminal inventories reached as low as 162,227 metric tonnes at the end of the 2024–2025 winter season (April 2025) and as high as 345,610 metric tonnes (August 2025). Point Tupper’s December 2025 inventories (255,173 metric tonnes) were 81% of its winter readiness target, almost identical to 2024 winter readiness. At Sydney, inventories ranged from 359,347 metric tonnes (February 2025) to 563,879 metric tonnes (December 2025). This December 2025 total meant a winter readiness target of 113%. Overall, NSPI’s total solid fuel inventory reached 819,052 metric tonnes, almost equal to the winter readiness target of 816,200 metric tonnes.

During 2025, NSPI deferred two cargoes of LSH coal scheduled for delivery in 2025, but those deferrals were not due to inventory levels. Specifically, NSPI deferred two cargoes of [REDACTED] LSH supply into 2026 following receipt of a CoV for SO₂ compliance in March 2025. The CoV significantly impacted NSPI’s optimal solid fuel mix and hedged positions relative to targets, making a deferral of these two cargoes an attractive option. (We address this deferral and procurement in Chapter IV).

V.B.5.c. Instances of Lost Fuel

NSPI reported six instances of lost solid fuel. All six were related to coal escaping from rail car doors during transportation on the Point Tupper-Trenton rail route. NSPI explained that it recovered almost the entirety of the spilled coal and transported it back to the Bear Head storage site. None of these incidents were reported by NSPI to environmental authorities; NSPI stated that all coal was contained on the tracks and not located near any waterways or environmentally sensitive areas. In each case, the lost coal was

discovered the day after the spill; combined, the amount of spilled coal totaled approximately 49 tonnes. Rail owner and provider CBNS used contractors to clean up the coal and return it to Bear Head, totaling \$95,763.57 in invoiced costs. These costs were passed through to FAM customers. During the Audit Period, NSPI scrapped a substantial portion of its railcar fleet due to their age and condition in favor of newer cars, which we explain in Chapter IV.

In our prior audit report, we identified two instances of coal pile sloughing at Point Tupper Marine Terminal and one at Bear Head.²⁴⁵ During this Audit Period, NSPI reported no sloughing events. In response to the prior audit period's sloughing events, NSPI installed an enhanced rainwater management system at Point Tupper Marine Terminal and, while that system was being constructed and installed, reduced the maximum capacity under the shuttle conveyor to 78,000 metric tonnes through December 2024. Following the rainwater management system's installation, NSPI increased the maximum capacity under the shuttle conveyor to 96,000 metric tonnes, consistent with a prior CBCL recommendation, but allowed capacity to reach as high as 120,000 metric tonnes if required and subject to the review and approval by the Director of ERM. NSPI stated that at no point during the Audit Period did inventories exceed 96,000 metric tonnes under Point Tupper Marine Terminal's shuttle conveyor. Above, in section V.B.1.b, we explain a capital investment project at Bear Head intended in part to reduce sloughing coal risks.

V.B.5.d. Train Derailment at Sydney Coal Railway

NSPI reported a single instance of a train derailment during the Audit Period. On October 6, 2025, there was a derailment of five railcars of a northbound, 21-car coal train on the Sydney Coal Railway connecting the International Pier to the Lingan generating station. While NSPI owns the Sydney Coal Railway, it contracts with [REDACTED] for the operation of the railway, including "preventative, breakdown and capital maintenance" of the railway.²⁴⁶ Upon derailment, [REDACTED] retrieved spilled coal volumes and addressed all cleanup and restoration efforts at no cost to NSPI. [REDACTED] provided a presentation to NSPI summarizing the event, including its view of the causes and ways to prevent future occurrences. NSPI also engaged [REDACTED] to provide its assessment of the event, which it provided at a small cost (\$513.00). Photos of the incident from [REDACTED] presentation are shown below.

²⁴⁵ 2022-2023 Bates White Audit Report, section V.B.5.c.

²⁴⁶ "[REDACTED] 0729 INP Services Agreement," PDF page 3.

Figure V-9: Overhead photo of train derailment

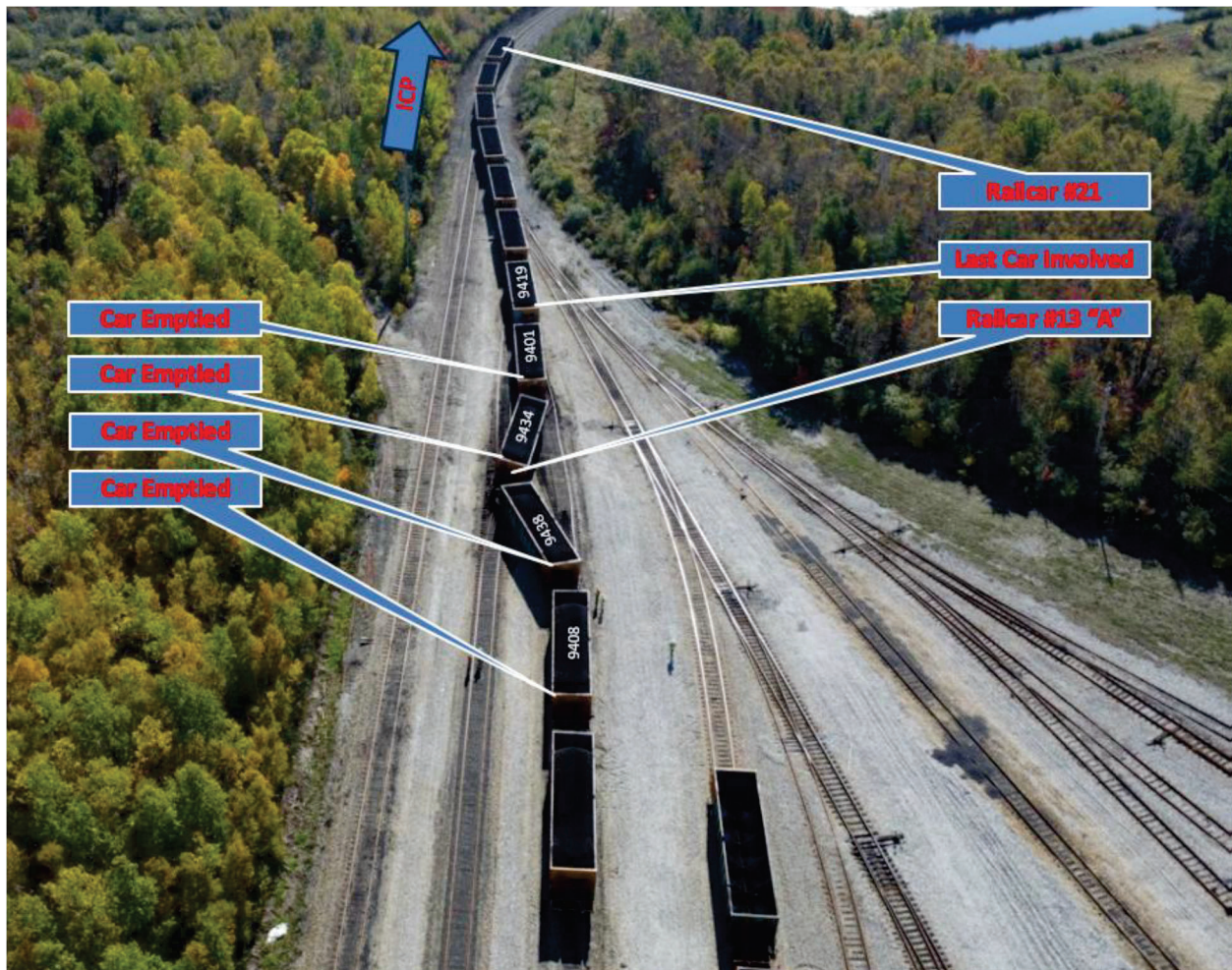


Figure V-10: Overhead photo of rail damage from derailment



█ described the incident as follows:

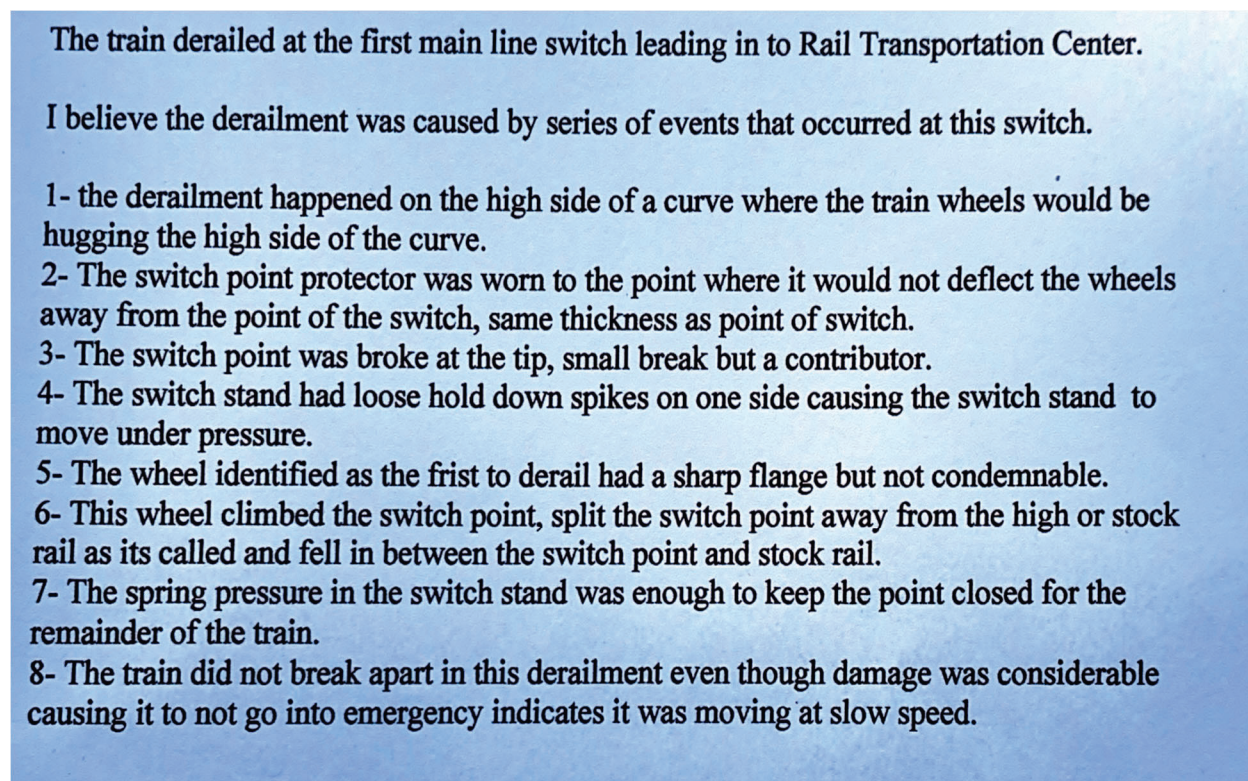
On October 6, 2025, at approximately 12:27 p.m., a northbound Sydney Coal Railway (SCR) coal train, with 21 loaded railcars, entered the serving yard for a routine meet with a southbound empty SCR coal train. Under standard operating procedures, loaded trains utilize the transfer track, while empty trains operate on track #2. Due to ongoing transfer track repairs, train meets had been temporarily reassigned to tracks #2 and #3. As the loaded train transitioned into the yard and entered track #2, the locomotives and the first 12 railcars diverged onto the intended track. The B-end of Railcar #13, however, picked the switch, while the A-end continued traveling along the adjacent track for approximately 350 feet, which resulted in five cars derailing.

█ concluded that the “contributing issues” included: (1) “non-routine tracks utilized for daily train meets,” (2) the “diverting switch point” was “defective,” (3) existence of a “track defect at Switch #48” that was previously unidentified, and (4) the defective switch #48 was “not subject to September [2025] monthly inspection, due to lockout.” To remedy these issues, █ planned to (1) replace Switch #48, (2) “[e]valuate [its] process for inspection of entire rail infrastructure, including locked out

equipment,” and (3) “[e]valuate the SCR infrastructure to identify opportunities for, modifications, or replacement or removal of redundancies.”

██████████ offered its assessment of the incident, which is shown in the figure below.

Figure V-11: ██████████ assessment of derailment



While the derailment did not impose costs on NSPI, the findings of Savage’s review and ██████████ conclusions demonstrate that there is room for improvement in the inspection and maintenance of the Sydney Coal Railway. While ██████████ is already at work on identifying and implementing those improvements, it would be prudent of NSPI to ensure that the improvements are being carried out and that ██████████ conclusions have also been considered by ██████████ in its improvement efforts. Besides safety and environmental impacts, derailments can also disrupt NSPI’s fuel supply chain. We therefore recommend that NSPI track Savage’s progress in implementing these improvements, including any implied by ██████████ inspection report.

V.B.5.e. Petroleum Hydrocarbon Release at Sydney Coal Railway Train Maintenance Facility

In this section, we provide details regarding the Sydney Coal Railway train maintenance facility. NSPI confirmed that the costs associated with this section were not FAM-recoverable costs, but these events involve FAM-related infrastructure.

Approximately halfway between the International Pier and the Lingan generating station is the Transportation and Railway Maintenance Centre (“TRMC”), which sits on the Sydney Coal Railway owned by NSPI. The TRMC is used as a depot for storing and maintaining railcars used to transport coal from the International Pier to Lingan. Late in 2023, [REDACTED] was retained by NSPI to complete environmental assessments to “determine the potential source(s) of petroleum hydrocarbon (PHC) sheen that had been identified in stormwater flowing from the discharge pipe on the west side of the site into a wet area on the adjoining/undeveloped Federal property identified by PID 15569635.”

[REDACTED] “oversaw clean out activities of the site’s stormwater drainage system” and completed a “Phase II Environmental Assessment” in November 2024 and a “Phase III Environmental Assessment” in May 2025. The Phase II Assessment found substantial evidence of contaminants in the soil (e.g., benzene), groundwater (e.g., ethylbenzene, xylenes, and PHC), and surface water (e.g., PHC). [REDACTED] recommended a Phase III Assessment “to delineate the extent of the PHC contamination.”

The Phase III Assessment “[did] not identif[y] evidence of significant PHC impacts in soil or groundwater on the TRMC site, except for a relatively minor area of soil PHC impacts in the location of the former underground storage tank (UST), and a sporadic PHC exceedance in groundwater monitoring well MW101 between the boiler building and the TRMC building.” The Phase III Assessment included recommendations “to complete additional assessment activities to achieve delineation of areas of PHC impacts that have not yet been fully delineated, to complete additional groundwater monitoring at the site to assess seasonal changes in PHC concentrations in groundwater, to perform wetland activities on the [adjacent Federal property], and to develop a Stormwater Quality Management Plan to outline measures that can be implemented at the site to mitigate the presence of PHCs in stormwater that are discharging from the TRMC site onto the adjoining [Federal] property.”

On May 22, 2025, [REDACTED] provided an additional report which concluded that the source(s) of the PHC leakage were from the following potential sources: (1) hydraulic oil leakage from rail maintenance equipment in the boiler building, (2) standing water with observed sheen in the large sump pit in the boiler building, (3) hydraulic fuel leakage into the floor trenches in the TRMC building where trains, rail cars, rail equipment, and trucks modified to drive on rail lines are moved and parked, (4) grease from railcars, and (5) residual coal dust from frequent coal transport operations. [REDACTED] then provided several mitigation options, including: (1) development of a Stormwater Quality Management Plan, (2) installation of oil/water separators on floor drain discharge from the boiler and TRMC buildings, (3) installation of a stormwater treatment system just prior to off-site discharge, and (4) completing long-term monitoring of the down-gradient wet area to document the expected natural attenuation of PHC impacts following implementation of the mitigation measures.

In the midst of [REDACTED] ongoing work, NSPI also retained [REDACTED] to provide a design option review of a spill containment system. On January 30, 2024, [REDACTED] provided its report, noting that “[t]he existing underground collection tank system appears to be compromised.” [REDACTED] reviewed three options, estimating their costs to be between \$51,000 and \$157,000 (-30%/+50%).

Separate from these environmental issues, NSPI also commissioned CBCL to provide an assessment of the TRMC building's roof, which it found to be in need of substantial maintenance or replacement.

██████████ August 2025 report recommended various phases of roof maintenance and replacement over a three-year period. NSPI then commissioned a cost estimate for this work from ██████████, which was provided on September 9, 2025, and totaled \$1,714,600.

To be clear, these projects above are capital projects that are not recovered through FAM. Nevertheless, the TRMC is a material part of NSPI's coal supply chain in Cape Breton, and its ability to remain in operation to support the Sydney coal circuit is relevant to FAM processes.

V.B.6. Physical Inventory Measurement and Adjustment

Per the Fuel Manual, plant management is responsible for solid fuel inventory supplies at NSPI's plants, while ERM is responsible for monitoring inventories at Point Tupper Marine Terminal and International Pier.²⁴⁷ On a quarterly basis, Fuels is responsible for surveying the solid fuel inventories, including those stockpiled at the individual plants.²⁴⁸ The Fuel Manual contains the methodology to be employed in the inventory survey, the thresholds that require corrective inventory adjustment actions, and the financial procedures that are to be taken to initiate those adjustments.

Specifically, if the physical survey for a given coal quality and commodity (e.g., low-sulphur, low Btu coal) is less than 95% or greater than 105% of NSPI's book inventory for two successive quarters, then NSPI adjusts the book inventory for the repeating portion of the variance.²⁴⁹ In other words, NSPI would make an adjustment equal to the lesser of the two quarterly variances and would never adjust inventory if physical inventory is within 5% of book inventory. Adjustments to book inventory levels are made by either increasing or decreasing the recorded consumption from the affected inventory location. For example, when the book inventory needs to be increased, consumption would be decreased in Aligné to accomplish this. To decrease book inventory in Aligné, consumption would be increased.

The following several tables (Figure V-12 – Figure V-17) show the inventory adjustments by plant or marine terminal, by quarter.

²⁴⁷ Fuel Manual Revision 14, section 12.

²⁴⁸ Fuel Manual Revision 14, Appendix M.

²⁴⁹ Fuel Manual Revision 14, Appendix M.

Figure V-12: Langan Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	Domestic	LT LSH	LT MS	LT Dom
Q1 2024 (metric tonnes)								
Q1 2024 (\$)								
Q2 2024 (metric tonnes)	-11,510		-3,525		1,987			
Q2 2024 (\$)	-\$2,681,564		-\$724,162		\$416,128			
Q3 2024 (metric tonnes)								
Q3 2024 (\$)								
Q4 2024 (metric tonnes)	-9,624	2,820	5,583					
Q4 2024 (\$)	-\$1,949,069	\$610,017	\$1,064,536					
Q1 2025 (metric tonnes)								
Q1 2025 (\$)								
Q2 2025 (metric tonnes)							-10,141	
Q2 2025 (\$)							-\$1,875,512	
Q3 2025 (metric tonnes)								
Q3 2025 (\$)								
Q4 2025 (metric tonnes)	15,603		-14,307				-10,727	
Q4 2025 (\$)	3,518,708		-2,280,506				-1,709,922	

Figure V-13: International Pier Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	Domestic	Long-Term
Q1 2024 (metric tonnes)		-682				
Q1 2024 (\$)		-\$760,943				
Q2 2024 (metric tonnes)	207					
Q2 2024 (\$)	\$43,805					
Q3 2024 (metric tonnes)			597			
Q3 2024 (\$)			\$127,736			
Q4 2024 (metric tonnes)	-1,825	205				
Q4 2024 (\$)	-\$368,857	\$44,302				
Q1 2025 (metric tonnes)			-3,761	2,278		
Q1 2025 (\$)			-\$804,383	\$390,725		
Q2 2025 (metric tonnes)	-4,165		-2,832			
Q2 2025 (\$)	-\$887,841		-\$373,714			
Q3 2025 (metric tonnes)						
Q3 2025 (\$)						
Q4 2025 (metric tonnes)				2,485		
Q4 2025 (\$)				\$303,090		

Figure V-14: Point Tupper Marine Terminal and Bear's Head Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	Domestic	Long-Term
Q1 2024 (metric tonnes)	1,104					
Q1 2024 (\$)	\$308,379					
Q2 2024 (metric tonnes)	2,092					
Q2 2024 (\$)	\$401,683					
Q3 2024 (metric tonnes)	91		3,725			
Q3 2024 (\$)	\$15,418		\$790,118			
Q4 2024 (metric tonnes)						
Q4 2024 (\$)						
Q1 2025 (metric tonnes)			7,047			
Q1 2025 (\$)			\$1,494,738			
Q2 2025 (metric tonnes)		-7,299	8,435			
Q2 2025 (\$)		-\$1,315,131	\$1,456,093			
Q3 2025 (metric tonnes)		-10,417	4,607			
Q3 2025 (\$)		-\$1,526,767	\$694,371			
Q4 2025 (metric tonnes)						
Q4 2025 (\$)						

Figure V-15: Point Aconi Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	Domestic	Long-Term
Q1 2024 (metric tonnes)		-682	2,623			
Q1 2024 (\$)		-\$187,192	\$745,634			
Q2 2024 (metric tonnes)				5,281		
Q2 2024 (\$)				\$868,910		
Q3 2024 (metric tonnes)			2,005			
Q3 2024 (\$)			\$477,912			
Q4 2024 (metric tonnes)	3,384		390			
Q4 2024 (\$)	\$672,166		\$83,691			
Q1 2025 (metric tonnes)	857		849			
Q1 2025 (\$)	\$170,127		\$182,002			
Q2 2025 (metric tonnes)						
Q2 2025 (\$)						
Q3 2025 (metric tonnes)						
Q3 2025 (\$)						
Q4 2025 (metric tonnes)						
Q4 2025 (\$)						

Figure V-16: Trenton 5 Inventory Adjustments

Adjustments	Trenton 5 Blend
Q1 2024 (metric tonnes)	
Q1 2024 (\$)	
Q2 2024 (metric tonnes)	5,921
Q2 2024 (\$)	\$1,248,766
Q3 2024 (metric tonnes)	-
Q3 2024 (\$)	\$821,708
Q4 2024 (metric tonnes)	
Q4 2024 (\$)	
Q1 2025 (metric tonnes)	
Q1 2025 (\$)	
Q2 2025 (metric tonnes)	
Q2 2025 (\$)	
Q3 2025 (metric tonnes)	
Q3 2025 (\$)	
Q4 2025 (metric tonnes)	-6,234
Q4 2025 (\$)	-\$946,644

Figure V-17: Trenton 6 Inventory Adjustments

Adjustments	Trenton 6 Blend
Q1 2024 (metric tonnes)	
Q1 2024 (\$)	
Q2 2024 (metric tonnes)	-7,464
Q2 2024 (\$)	-\$1,500,131
Q3 2024 (metric tonnes)	
Q3 2024 (\$)	
Q4 2024 (metric tonnes)	
Q4 2024 (\$)	
Q1 2025 (metric tonnes)	
Q1 2025 (\$)	
Q2 2025 (metric tonnes)	
Q2 2025 (\$)	
Q3 2025 (metric tonnes)	
Q3 2025 (\$)	
Q4 2025 (metric tonnes)	-5,003
Q4 2025 (\$)	-\$689,538

Figure V-18: Total Inventory Adjustments

Quarter	Metric Tonnes	Dollars
Q1 2024	599	
Q2 2024	(7,011)	
Q3 2024	6,418	
Q4 2024	933	
Q1 2025	7,270	
Q2 2025	(16,002)	
Q3 2025	(5,810)	
Q4 2025	(18,183)	
Total	(31,786)	

We reviewed these adjustments for concerning trends or quantities in adjustments. About 61% of the inventory adjustments observed in the Audit Period were positive, i.e., they increased the amount of fuel in inventory. However, Figure V-18 shows that, fleetwide, total adjustments were on net negative and resulted in a reduction adjustment for the two-year Audit Period of -\$3.7 million, which is in line with prior audit periods, and a substantial reduction from the prior audit period (-\$19.8 million in 2022-2023, -\$3.9 million in 2020-2021 and -\$6.8 million in 2018-2019).²⁵⁰

Inventory adjustments were highest in the months following the cyber event (e.g., Q2 2025 through Q4 2025). NSPI acknowledged that tracking inventories was made more difficult during the aftermath of the cyber event due to loss of access to the Aligner system. Instead of consumption data being a direct input from the PI system to Aligner (which then updated plant inventories), NSPI's plant personnel kept a spreadsheet database to manually track inventory levels using delivery and transfer data, as well as plant consumption data, to do so. This manual process is less reliable than an automated process (as was traditionally in place using PI and Aligner), and the larger inventory adjustments in the final three quarters of the Audit Period show the impact.

Still, the purpose of NSPI's quarterly coal inventory surveys is to verify (and correct, if necessary) solid fuel inventory levels, and those quarterly surveys accomplished their purpose during this time. NSPI conducted those surveys in each quarter of 2025 and made inventory adjustments accordingly.

NSPI experienced multiple issues at Trenton 5 and Trenton 6 during the Audit Period related to solid fuel consumption and inventories. First, in the third quarter of 2024, NSPI discovered an error in the Trenton 5 coal blend, which caused NSPI's assumptions about the fuel mix being consumed by Trenton 5 to be incorrect back to the fourth quarter of 2023. Specifically, the error caused an overstatement of mid-sulfur and LSL coal consumption and an understatement of LSH consumption. This was causing Trenton 5 heat rates to be calculated lower than expected. NSPI addressed this error by making adjustments to inventory and consumption data in the third quarter of 2024. The implication for this error is that heat

²⁵⁰ 2022-2023 Bates White Audit Report, section V.B.6.

rates have been incorrectly stated for Trenton 5, at minimum, and potentially Trenton 6 and Point Tupper in historical FAM reports. We include a recommendation that NSPI correct any reported heat rate data for these three units since the fourth quarter of 2023.

Second, NSPI experienced issues with tracking inventories at Trenton 5 and Trenton 6 during the Audit Period following the cyber event. Specifically, NSPI had trouble determining the split of volumes delivered to Trenton 5 and Trenton 6 from Point Tupper Marine Terminal. In the fourth quarter of 2025, NSPI determined to make substantial inventory adjustments to the respective inventories of Trenton 5 and Trenton 6 to match inventory survey results. For inventory and consumption tracking purposes, NSPI therefore transferred 4,157 tonnes of MS coal from Trenton 6 to Trenton 5 and 21,578 tonnes of LSL coal from Trenton 5 to Trenton 6. One contributor to this tracking error was the different blends consumed at Trenton 5 and Trenton 6 during this time. Notwithstanding the impact of the cyber event and NSPI's efforts to restore its systems and processes to those in place prior to the cyber event, NSPI was burning the same blends of fuels at both Trenton 5 and Trenton 6 at the close of the Audit Period (80% LSL, 20% MS coals). When the generating units' blends are the same, this simplifies the logistics for these two plants, as the same fuel mixes can be offloaded and added to each generating unit's inventory pile. This may mitigate the likelihood of frequency and magnitude of this type of error in the future, at least as long as the two units' fuel blends remain the same.

V.B.7. Bates White's 2022-2023 Audit Recommendations

Our prior audit report contained one recommendation related to non-biomass Solid Fuel Supply Management. It stated:

Recommendation V-1: NSPI should review its contract administration process for the Donkin supply agreement with [REDACTED] to determine if performance tracking can be enhanced.

NSPI accepted this recommendation and committed to developing methods to tracking weekly deliveries and to identify instances when monthly contractual thresholds were unlikely to be met. As we explain above, however, NSPI received no new mined supply from the Donkin Mine during the Audit Period, as the mine remained closed throughout. Moreover, the contract with [REDACTED] that was the subject of this recommendation expired on December 31, 2024. As such, we consider this recommendation to no longer be applicable and NSPI's response to this recommendation to have been reasonable.

V.C. Conclusions

Conclusion V-1: NSPI's use of Align to track solid fuel remains appropriate. Align allows NSPI to reconcile the entire solid fuel supply chain and interacts directly with other NSPI programs, including

NSPI's billing system (Oracle), thus reducing the likelihood of errors across the long chain of solid fuel management, from contract origination to billing of FAM customers.

Conclusion V-2: From April 25, 2025 to October 30, 2025, Aligné was unavailable due to the cyber event and would only become available to more users on November 24, 2025. As of the end of the Audit Period, Aligné was still in the process of being backfilled, and NSPI did not anticipate relying fully on Aligné Fuels until the end of the second quarter of 2026. The cyber event did not impact Aligné's historical database (pre-April 25, 2025 data), which was housed on off-site servers.

Conclusion V-3: NSPI's processes and procedures for receipt of solid fuel also remain reasonable. NSPI competently manages a complex set of logistics to receive imported coal at two ports, move that supply to its plants by rail and truck, and receive domestic sources of solid fuel at multiple plants. ERM and the plant personnel have clearly delineated responsibilities in managing solid fuel supply that, during the Audit Period, were carried out effectively. NSPI's ability to schedule vessel shipments to either of its two receipt terminals is a useful contractual flexibility.

Conclusion V-4: During the April 25, 2025 to December 31, 2025 period, the process for tracking and recording deliveries of solid fuel was done outside of Aligné. Contract quantities and qualities were verified under normal operating procedures, as Aligné has no material role in the fuel quality assurance process. Deliveries were added to a spreadsheet-based tracking mechanism using bills of lading, while consumption data was provided by the plants, which continued to track consumption through either PI or DCS/SCADA, which continued to run and was unaffected by the cyber event. Plant personnel provided consumption data to the Fuels team, which updated the Excel-based tracking mechanism for each inventory location.

Conclusion V-5: NSPI's processes for sampling, weighing, and testing coal and petcoke for quantity and quality specifications remain reasonable, appropriately use a third party for assistance, and include a series of test points to ensure effectiveness.

Conclusion V-6: NSPI's contract administration processes remain reasonable and include appropriate collaboration among ERM, senior NSPI management, terminal personnel, and plant personnel. During the aftermath of the cyber event, NSPI used Excel-based workarounds to manage the loss of access to Aligné and Oracle.

Conclusion V-7: NSPI's fuel handling costs at International Pier and Point Tupper Marine Terminal decreased by 67 percent and 42 percent, respectively, from the prior year.

Conclusion V-8: NSPI undertook several studies during the Audit Period which have implications for the Point Tupper Marine Terminal (and Bear Head site) and the International Pier. While these reports did not directly impact FAM costs during the Audit Period, they are indicative of the condition of these assets and may portend future capital costs, which can have an impact on FAM costs.

Conclusion V-9: NSPI enjoyed generally positive contract compliance in terms of quantities of solid fuel from its suppliers during the Audit Period. We observed no instances of solid fuel suppliers delivering volumes that differed from acceptable contract ranges.

Conclusion V-10: NSPI also enjoyed positive contract compliance from solid fuel suppliers regarding solid fuel quality during the Audit Period. All tested samples were within contractual quantity tolerances. In all cases, we confirmed that prices were calculated correctly and in line with the underlying contractual arrangements.

Conclusion V-11: NSPI's processes and procedures for solid fuel inventory targets remain reasonable.

Conclusion V-12: NSPI's solid inventory levels during the Audit Period were reasonable and we observed no incidents of excess inventories or diverted or delayed deliveries due to inventory level concerns.

Conclusion V-13: During 2025, NSPI deferred two cargoes of LSH coal scheduled for delivery in 2025 into 2026 following receipt of a CoV for SO₂ compliance in March 2025. The CoV significantly impacted NSPI's optimal solid fuel mix and hedged positions relative to targets, making a deferral of these two cargoes an attractive option.

Conclusion V-14: NSPI reported six instances of lost solid fuel totaling 49 tonnes, each related to coal escaping from rail car doors during transportation on the Point Tupper-Trenton rail route. NSPI explained that it recovered almost the entirety of the spilled coal and transported it back to the Bear Head storage site. No incidents were reported by NSPI to environmental authorities, according to NSPI, due to all coal being contained on the tracks and not located near any waterways or environmentally sensitive areas. In each case, the lost coal was discovered the day after the spill and cleaned up by contractors hired by rail owner and provider CBNS. Total invoiced costs were \$95,763.57, which were passed through to FAM customers.

Conclusion V-15: During this Audit Period, NSPI reported no coal sloughing events. NSPI installed an enhanced rainwater management system at Point Tupper Marine Terminal and, while that system was being constructed and installed, reduced the maximum capacity under the shuttle conveyor to 78,000 metric tonnes through December 2024. Following the rainwater management system's installation, NSPI increased the maximum capacity under the shuttle conveyor to 96,000 metric tonnes, consistent with a prior [REDACTED] recommendation, but allowed capacity to reach as high as 120,000 metric tonnes if required and subject to the review and approval by the Director of ERM.

Conclusion V-16: On October 6, 2025, there was a derailment of five railcars of a northbound, 21-car coal train on the Sydney Coal Railway connecting the International Pier to the Lingan generating station. While NSPI owns the Sydney Coal Railway, it contracts with [REDACTED] for the operation of the railway, including "preventative, breakdown and capital maintenance" of the railway. Upon derailment,

██████ retrieved spilled coal volumes and addressed all cleanup and restoration efforts at no cost to NSPI. While the derailment did not impose costs on NSPI, the findings of ██████ review and ██████ conclusions demonstrate that there is room for improvement in the inspection and maintenance of the Sydney Coal Railway. While ██████ is already at work on identifying and implementing those improvements, it would be prudent of NSPI to ensure that the improvements are being carried out and that ██████ conclusions have also been considered by ██████ in its improvement efforts. Besides safety and environmental impacts, derailments can also disrupt NSPI's fuel supply chain. We therefore recommend that NSPI track Savage's progress in implementing these improvements, including any implied by ██████ inspection report. **(Recommendation V-1)**

Conclusion V-17: NSPI engaged multiple contractors to assess several potential capital projects at the Transportation and Railway Maintenance Centre on the Sydney Coal Railway system. Some of these projects relate to NSPI's discovery of petroleum hydrocarbon releases at the facility, which required cleanup. While these projects above are capital projects that are not recovered through FAM, they are notable for FAM customers as the TRMC is a material part of NSPI's coal supply chain in Cape Breton, and its ability to remain in operation to support the Sydney coal circuit is relevant to FAM processes.

Conclusion V-18: About 61% of the inventory adjustments observed in the Audit Period were positive, i.e., they increased the amount of fuel in inventory. However, total adjustments were net negative overall and resulted in a reduction adjustment for the two-year Audit Period of just under \$3.7 million, which is in line with prior audit periods, and a substantial reduction from the prior audit period.

Conclusion V-19: Inventory adjustments were highest in the months following the cyber event (e.g., Q2 2025 through Q4 2025). NSPI acknowledged that tracking inventories was made more difficult during the aftermath of the cyber event due to loss of access to the Aligne system. Instead of consumption data being a direct input from the PI system to Aligne (which then updated plant inventories), NSPI's plant personnel kept a spreadsheet database to manually track inventory levels using delivery and transfer data, as well as plant consumption data, to do so. This manual process is less reliable than an automated process (as was traditionally in place using PI and Aligne), and the larger inventory adjustments in the final three quarters of the Audit Period show the impact. Still, the purpose of NSPI's quarterly coal inventory surveys is to verify (and correct, if necessary) solid fuel inventory levels, and those quarterly surveys accomplished their purpose during this time. NSPI conducted those surveys in each quarter of 2025 and made inventory adjustments accordingly.

Conclusion V-20: In the third quarter of 2024, NSPI discovered an error in the Trenton 5 coal blend, which caused NSPI's assumptions about the fuel mix being consumed by Trenton 5 to be incorrect back to the fourth quarter of 2023. The error caused an overstatement of mid-sulfur and LSL coal consumption, an understatement of LSH consumption, and understated Trenton 5 heat rates. NSPI addressed this error by making adjustments to inventory and consumption data in the third quarter of 2024. The implication for this error is that heat rates have been incorrectly stated for Trenton 5, at minimum, and potentially

Trenton 6 and Point Tupper in historical FAM reports. We include a recommendation that NSPI correct any reported heat rate data for these three units since the fourth quarter of 2023. **(Recommendation V-2)**

Conclusion V-21: NSPI fully addressed our prior audit report's recommendation related to solid fuel supply management.

V.D. Recommendations

Recommendation V-1: NSPI should track [REDACTED] progress in implementing improvements following the October 6, 2025 derailment on the Sydney Coal Railway line, including any implied by [REDACTED] inspection report.

Recommendation V-2: NSPI should correct any previously-reported heat rate data for Trenton 5, Trenton 6, and Point Tupper that were impacted by incorrect assumptions about the fuel mix consumed by Trenton 5 from the fourth quarter of 2023 to the third quarter of 2024.

VI. Biomass Procurement and Supply Management

VI.A. Background

In this chapter, we review and assess NSPI's procurement and supply management of biomass fuel. We begin by explaining NSPI's biomass fuel-fired generator, the Port Hawkesbury Biomass Unit ("PHB"). Next, we look at NSPI's consumption of biomass fuel during the Audit Period for the purpose of generating electricity. We then explain the sources and types of NSPI's biomass fuel. Next, we discuss the prices NSPI paid for biomass fuel during the Audit Period. We then summarize NSPI's supply contracts for biomass fuel and all existing NSPI supply arrangements entering the Audit Period. We then review new supply arrangements for biomass fuel executed during the Audit Period. Next, we provide our assessment of NSPI's biomass fuel procurement process. We then review all contract actions taken by NSPI during the Audit Period related to the biomass contracts (e.g., amendments, litigation, force majeure). We then provide an assessment of NSPI's procurement of biomass fuel-related goods and services, such as fuel handling.

We then turn to biomass supply management. This includes NSPI's process for receiving biomass fuel, its procedures for measuring quantity and quality of fuel, and measuring biomass supply contract compliance. We review the biomass fuel inventory adjustment process and Audit Period results. We conclude with a review of NSPI's actions taken in response to biomass-related recommendations from our prior audit report.

VI.B. Findings

VI.B.1. The Port Hawkesbury Biomass Unit

Biomass fuel is consumed in a single power plant in NSPI's fleet. PHB is a 43 MW²⁵¹ biomass fuel-fired generator located in Port Hawkesbury that also has the capability to burn natural gas. The boiler combusts biomass fuel and, at times, natural gas to produce steam, and is co-located at the Port Hawkesbury Paper ("PHP") plant. Biomass fuel comes from both PHP (primary and secondary biomass fuel delivered to NSPI under supply agreements, plus waste from the paper-making process (bark and "sludge")) and NSPI (primary biomass fuel, secondary biomass fuel). Steam produced by the boiler is first diverted to meet PHP's operational needs, while the remainder is used to generate electricity. PHP is responsible for procuring fuel for its operations and NSPI is responsible for procuring fuel for the generation of electricity.

²⁵¹ 2025 FAM Annual Report, A2NC.

VI.B.2. Biomass Fuel Consumption

NSPI consumed █████ green metric tonnes (“GMT”) of biomass fuel during the Audit Period.²⁵² Figure VI-1 provides this data in more detail, as broken down between 2024 and 2025. Consumption in 2025 was █████ than in 2024.

Figure VI-1: NSPI’s Solid Fuel Consumption vs. Forecast (2024, 2025)²⁵³

Solid Fuel Type	2024			2025		
	Consumption (GMT)	Forecast (GMT)	Comparison	Consumption (GMT)	Forecast (GMT)	Comparison
Biomass	█████	█████	█████	█████	█████	█████

Biomass consumption for the Audit Period was the highest in recent history in both GMT and MMBtu terms. As a result, PHB output was also historically high, producing █████ GWh.²⁵⁴ For example, this total represents an increase of 22% over the prior Audit Period, when PHB produced █████ GWh,²⁵⁵ and a █████% increase over the 2020-2021 audit period, when PHB’s output was █████ GWh.²⁵⁶

Higher biomass consumption during the Audit Period was primarily driven by the treatment of the OBPS program, which often results in the unit being the lowest cost dispatchable resource. To calculate the OBPS price impact of PHB, NSPI uses the carbon price and the forecast fleet-wide carbon emissions intensity and then assumes that PHB’s output will reduce that intensity. This generates large OBPS credits: PHB generated █████ in OBPS credits in 2024 and █████ in 2025. PHB is the only generator in NSPI’s fleet that reliably generates OBPS credits.

Also important is the availability of the PHB unit. PHB’s Availability Factors in 2024 (84%) and 2025 (87%) were strong and above industry averages, as explained in Chapter X. Still, biomass consumption represents just a small portion of the fuel and cost that serves FAM customer load, as shown in the figure below. For the Audit Period, NSPI consumed █████ GMT of biomass fuel for every MWh of the system’s net requirement. For comparison, NSPI consumed █████ metric tonnes of non-biomass solid fuel for each MWh of Net System Requirement in the Audit Period.²⁵⁷

²⁵² Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).
²⁵³ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).
²⁵⁴ 2024 FAM Annual Report, A2NC; 2025 FAM Annual Report, A2NC.
²⁵⁵ 2022 FAM Annual Report, A2NC; 2023 FAM Annual Report, A2NC.
²⁵⁶ 2020 FAM Annual Report, A2NC; 2021 FAM Annual Report, A2NC.
²⁵⁷ 2024 and 2025 Q4 FAM Reports, tabs “3 (3)” and “Q6.”

Figure VI-2: NSPI's Biomass Consumption, Net System Requirement vs. Prior Audit Periods (GMT, MWh)²⁵⁸

Audit Period	Biomass Consumption (MT)	Net System Requirement (MWh)	Biomass Consumed per MWh
2018-2019			
2020-2021			
2022-2023			
2024-2025			

Figure VI-3 below shows annual consumption of biomass fuel since 2018 both in GMT and MMBtu. Heat content of the fuel during the Audit Period, as proxied here by “MMBtu/Tonne,” recovered in 2024 and 2025 from results in 2023, when the blend of biomass fuel consumed at PHB experienced higher overall moisture content.

Figure VI-3: Annual Biomass Consumption, Green Metric Tonnes and MMBtu (2018-2025)²⁵⁹

Year	Actual (tonnes)	Actual (MMBtu)	MMBtu/Tonne
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

VI.B.3. Biomass Fuel Sources and Types

PHB consumes primary biomass, which consists of wood chips or roundwood, and secondary biomass, which consists of bark. There are numerous sub-categories of primary biomass (e.g., “forest chips,” “sawmill chips,” etc.) and secondary biomass (“sawmill bark,” “forest bark,” and so on), but from an operational perspective, NSPI separates its biomass fuel into these two categories. Primary biomass is of higher quality due to its higher Btu content, which is a result of its lower moisture content. Secondary biomass is lower cost on a per-GMT basis due to its lower quality (i.e., higher moisture content). Bark is also a byproduct of the pulpwood and saw log production process, while wood chips require harvesting and chipping, further explaining price differences. These two fuels are blended throughout the year along with sludge, a high-moisture content byproduct of PHP’s paper-making industrial process. The unit also

²⁵⁸ 2018, 2019, 2020, 2021, 2022, 2023, 2024, and 2025 Q4 FAM Reports, tabs “3 (3)” and “Q6.”

²⁵⁹ 2018, 2019, 2020, 2021, 2022, 2023, 2024, and 2025 Q4 FAM Reports, tabs “3 (3).”

consumes a material amount of natural gas, which made up approximately █████ of the unit’s output in the Audit Period.²⁶⁰

VI.B.4. Biomass Fuel Prices

Biomass fuel costs averaged █████/green metric tonne in 2024 and █████/green metric tonne in 2025. These numbers include the fixed cost associated with the biomass unit, such as fuel handling, fuel sampling, and silviculture. The figure below shows the actual cost of consumed biomass as compared to the forecast.

Figure VI-4: Biomass Prices (\$/GMT) (Actual vs. Forecast)²⁶¹

Solid Fuel Type	2024		2025	
	Actual	Forecast	Actual	Forecast
Biomass	█████	█████	█████	█████

Another measure for the cost of biomass fuel during the period is the daily fuel cost for the Port Hawkesbury biomass unit that was used by NSPI in committing and dispatching the system. The fuel costs used in dispatching the system are meant to capture the replacement cost of the fuel being burned and thus should reflect the changes in market prices for biomass fuel. The figure below shows that the modeled cost of biomass fuel ranged from just below █████/MMBtu to a high of about █████/MMBtu in January 2025. The data for April 2025 through December 2025 was lost in the cyber event and was “backfilled” by NSPI in PortOps. This impacts the reliability of this data. We address the accuracy of these costs in Chapter XI of our report.

²⁶⁰ 2024 FAM Annual Report, A-10(29); 2025 FAM Annual Report, A-10(29).
²⁶¹ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).

Figure VI-5: Monthly Fuel Prices Used in Dispatch, [REDACTED] (\$/MMBtu)



VI.B.5. NSPI's Biomass Fuel Procurement Process Assessment

NSPI's biomass fuel procurement processes are contained in NSPI's Fuel Manual. The Fuel Manual calls for use of multiple procurement strategies, including [REDACTED]

[REDACTED]²⁶² [REDACTED]
[REDACTED]
and since "[REDACTED]"
[REDACTED]²⁶³

The Fuel Manual clearly explains how supply offers for biomass fuel are to be evaluated when procured competitively. Evaluations are to consider commodity cost, transportation cost, handling and storage costs, and biomass fuel quality. While it is contemplated that [REDACTED]
[REDACTED], "other alternative sources of biomass that "[REDACTED]" can be procured as well.

Another important process is NSPI's recordation of procurement approval by the FST, which is typically well documented and contained in the Fuels Data Cart. These "Record of Procurement

²⁶² Fuel Manual Revision 14, Link 8, page 2.

²⁶³ Fuel Manual Revision 14, Link 8, page 3.

Approval” documents are issued for all solid fuel procurements—not just those related to RFPs. These documents ensure that purchases are vetted by management and are sufficiently justified, including showing the need for the purchase, the reasons for transacting with the counterparty, and the evaluation modeling done by ERM to assess the transaction.

NSPI’s processes for biomass procurement as codified in the Fuel Manual are reasonable and (as explained later in this chapter) were enhanced in response to a prior audit recommendation. NSPI favored use of competitive procurement during the Audit Period for biomass fuel. We explain the results of NSPI’s biomass procurement efforts below.

VI.B.6. NSPI’s Suppliers of Biomass Fuel

During the Audit Period, NSPI contracted with [REDACTED] suppliers of biomass fuel. These included [REDACTED] sawmills, plus [REDACTED]. Some supply agreements effective during the Audit Period were executed in 2023, with others executed during the Audit Period, both in 2024 and 2025.²⁶⁴ All supply agreements included specified or minimum volumes of biomass fuel, categories of fuel, fuel prices, and payment terms. Contracts typically included fuel quality requirements and supplier certifications about the source of the biomass fuel. We address specifics about the biomass supply agreements below. Figure VI-6 summarizes NSPI’s suppliers of solid fuel during the Audit Period.

Figure VI-6: NSPI Solid Fuel Suppliers During Audit Period²⁶⁵

Supplier	Product
[REDACTED]	Sawmill bark/biomass roundwood/fuel log chips/chips and grindings
[REDACTED]	Sawmill bark/chips
[REDACTED]	Fuel log chips/forest fuel chips/bark
[REDACTED]	Sawmill bark/chips
[REDACTED]	Sawmill bark

²⁶⁴ “Fuels Contracts,” “Biomass.”

²⁶⁵ FAM Quarterly Reports, tabs “Q3” and “Q4.”

VI.B.7. New Biomass Supply Agreements during the Audit Period

During the Audit Period, NSPI entered into several new contracts for solid fuel supply. We reviewed each of these contracts and the process by which those contracts were executed—this includes how winning suppliers were selected and why NSPI sought additional supply. Below, we provide a summary of all new contracts signed over the two-year Audit Period.

Before getting into the details, we wish to draw out two key points that are important to keep in mind when reviewing quarterly results. First, NSPI's forecasted output from PHB increased materially during the Audit Period. For example, NSPI's expected output from PHB in 2025 increased by 22 GWh from its Q1 2024 forecast to its Q4 2024 forecast, an increase of █%. For 2026 PHB output, NSPI's forecast increased by 28 GWh (or █%) over that same period. These increases helped drive higher procurement targets.

Second, NSPI increased the percentage of primary biomass fuel in the PHB blend, reaching as high as █% during the Audit Period, with tests as high as █%. This is a substantial departure from the prior audit period, when NSPI indicated a maximum blend of █% primary fuel and recent historical data where NSPI burned blends that ranged between █% and █% bark. NSPI explained that its new blends were based on increased operational experience and extended testing with lower moisture content blends, and their development and adoption reflected the █ for low-cost bark. This fuel mix change afforded higher consumption and procurement of primary biomass fuel.

VI.B.1.a. Pre-Existing Biomass Supply Agreements

Entering the Audit Period, NSPI had supply agreements with █ suppliers: █. ²⁶⁸ We addressed these contracts in our prior Audit Report. ²⁶⁹

VI.B.1.b. First Quarter 2024

NSPI entered into one new contract for biomass supply in the first quarter of 2024. NSPI also materially amended one other. This is shown in Figure VI-7.

²⁶⁶ "█ 20231015 Biomass Purchase Sale Agreement."

²⁶⁷ "█ - 20230122 Biomass Purchase Sale Agreement;" "█ - 20231231 First Amending agreement."

²⁶⁸ "█ 0118 2023 Biomass Supply Agreement."

²⁶⁹ 2022-2023 Bates White Audit Report, Section VI.A.7.

Figure VI-7: NSPI new biomass supply contracts (Q1 2024)

Supplier	Product	Quantity (GMT)	Term
[REDACTED]	Sawmill Bark	[REDACTED]	[REDACTED]
	Biomass Roundwood	[REDACTED]	[REDACTED]
	Fuel Logs — Extra Volume (Amending Agreement)	[REDACTED]	[REDACTED]

On January 30, 2024, NSPI received approval from the FST to negotiate a supply agreement with [REDACTED] for both primary and secondary biomass fuel. The decision was based on the outcome of the Q4 2023 fuel and purchased power PLEXOS forecast, which forecasted an open position of [REDACTED] % ([REDACTED] GMT) for secondary biomass in 2024, and a small open position of [REDACTED] % ([REDACTED] GMT) of primary biomass fuel. NSPI contacted [REDACTED] which on December 18, 2023 offered [REDACTED] GMT of bark and [REDACTED] GMT of roundwood (fuel logs). [REDACTED] offer was a bundled, take-or-leave total offer, meaning NSPI could not select the bark offer only. NSPI assessed the offer against bids received (and in some cases, selected) in a June 2023 biomass supply RFP. NSPI determined that the bark offer was “[REDACTED] of offered bark as evaluated in the June 2023 RFP,” while the offered primary biomass was [REDACTED] priced than [REDACTED] selected offers in the June 2023 RFP. The FST approved the request to negotiate a supply agreement, which had an estimated total cost of [REDACTED] million.

However, upon entering negotiations, [REDACTED] changed its offer, increasing the price of its bark by about [REDACTED] %, decreased the offered bark volume to [REDACTED] GMT (from [REDACTED] GMT), and most materially, doubling the quantity of roundwood offered to [REDACTED] GMT. This increased the total estimated transaction cost to [REDACTED] million. NSPI again sought FST approval to contract with [REDACTED] under these revised terms, reiterating the bundled nature of the offer from [REDACTED] and noting the “lack of secondary biomass (bark supply)” alternatives to [REDACTED] offer. The FST approved the transaction and on February 1, 2024, NSPI executed a contract with [REDACTED] that matched the negotiated terms.²⁷⁰ We note NSPI’s good practice here of bringing this revised offer from [REDACTED] to the FST.

Assessing NSPI’s decision-making on this issue is not straightforward. NSPI’s purchased bark from [REDACTED] was reasonable on its own: its fully evaluated price ([REDACTED]/MMBtu) was economic compared to bark selected in the June 2023 RFP ([REDACTED]/MMBtu, [REDACTED]).²⁷¹ The quantity ([REDACTED] GMT) was higher than NSPI’s forecasted need ([REDACTED] GMT), but was not overly excessive, and the advantageous economics of PHB, particularly under the OBPS regime, would encourage higher output at PHB. However, the purchase of bark was tied to procurement of [REDACTED] GMT of fuel logs, [REDACTED] GMT of which were surplus to NSPI’s 2024 needs, and which had a fully evaluated price of [REDACTED]/MMBtu, [REDACTED] % higher than the highest priced offer selected in the June 2023 RFP ([REDACTED]/MMBtu, [REDACTED] fuel log chips). That evaluated price included the cost of chipping the logs into consumable fuel, which necessitated an amendment to NSPI’s biomass fuel supply agreement with [REDACTED] at a cost of [REDACTED]/GMT, or a total

²⁷⁰ “[REDACTED] 0201 Biomass Fuel Purchase And Sale Agreement.”

²⁷¹ “[REDACTED] - 20231231 First Amending agreement.”

estimate of [REDACTED] for the [REDACTED] GMT volume. [REDACTED] other offers in that RFP were also superior to [REDACTED] January 2024 offer, though NSPI explained that [REDACTED] of those offers was for a small quantity ([REDACTED] GMT, [REDACTED]) and was “being pursued” at that time, while the other offer was [REDACTED] and “[was] being delivered to NS Power through the [REDACTED] Biomass Supply Agreement, at the [REDACTED] contracted price.”

The fuel log purchase, on its own, therefore, was not in FAM customers’ best interest. NSPI did not need [REDACTED] GMT of the [REDACTED] GMT, and the price offered was not economic to offers received in the June 2023 RFP. NSPI indicated in its RFP and in discussions with Bates White that bark supply in 2024 was limited, and we acknowledge that NSPI had selected bark from [REDACTED] in the June 2023 RFP, [REDACTED] of the [REDACTED] biggest [REDACTED] providers in the province, as well as [REDACTED]. It may be that there were no other supplies of bark available, but we were not provided with definitive proof of this. Moreover, as we explain in the next subsection, NSPI procured additional bark from [REDACTED] in April 2024.

It is clear to us that the PHB unit remained highly economic, even with the impact of the [REDACTED] fuel logs purchased from [REDACTED]. The large OBPS credits generated by the unit are so large (nearly [REDACTED]/MWh in 2025) that there is substantial headroom to absorb higher biomass fuel costs before the PHB unit becomes uneconomic. On net, therefore, this additional fuel from JDI was beneficial for customers.

In all, NSPI received [REDACTED] GMT of fuel logs from [REDACTED] in 2024 via deliveries made from February through November of 2024. However, we did not observe any instances of PHP providing chipping services for the fuel logs to make them ready for consumption in the PHB boiler until January of 2025. NSPI does not have any covered storage at the PHB site, meaning that these fuel logs were stored for months subject to the elements, which can harm their moisture content and quality and therefore the efficiency of the PHB boiler. NSPI stated that the risk associated with long periods of storage was limited to logs on the outside of the pile (the portion exposed to the elements). NSPI also stated that the logs were held in reserve and chipped only when needed. We do not have an estimate of the impact of the extended storage of the fuel logs prior to chipping.

VI.B.1.c. Second Quarter 2024

On April 3, 2024, NSPI received FST approval to purchase an incremental [REDACTED] GMT of bark from [REDACTED] at a cost of [REDACTED]/GMT, or an estimated [REDACTED] overall. The ROA explained that [REDACTED] requested to exercise a clause within its existing agreement to increase the bark volume of its supply contract by [REDACTED]%, or [REDACTED] GMT. NSPI’s ROA indicated that its most recent fuel and purchased power forecast showed consumption of bark at [REDACTED] GMT (up from [REDACTED] GMT), suggesting that procuring more bark at existing contractual prices would be beneficial.

The ROA also stated that during discussions with [REDACTED], the supplier indicated that it had additional bark volumes to offer beyond the current contractual limits. Per our discussion of the [REDACTED] bark-

and-fuel logs purchase in January 2024, it is unclear if [REDACTED] would have been able to submit a competing offer to [REDACTED] in the January 2024 timeframe.

VI.B.1.d. Third Quarter 2024

NSPI entered into no new contracts for biomass supply in the third quarter of 2024.

VI.B.1.e. Fourth Quarter 2024

The fourth quarter of 2024 was particularly active for NSPI regarding biomass supply procurement. NSPI extended supply agreements with [REDACTED] suppliers ([REDACTED]) and entered into one new contract ([REDACTED]). NSPI also materially amended two of its existing biomass supply agreements in the quarter. This is shown in Figure VI-8.

Figure VI-8: NSPI new biomass supply contracts (Q4 2024)

Supplier	Product	Quantity (GMT)	Term
[REDACTED]	Forest Chips	[REDACTED]	[REDACTED]
	Sawmill Bark	[REDACTED]	
	Biomass Roundwood	[REDACTED]	[REDACTED]
	Chips and Grindings	[REDACTED]	
[REDACTED]	Forest Chips	[REDACTED]	[REDACTED]
	Sawmill Chips	[REDACTED]	
	Bark	[REDACTED]	
[REDACTED]	Forest Chips	[REDACTED]	[REDACTED]
	Fuel Log Chips	[REDACTED]	
	Bark	[REDACTED]	

June 2024 RFP and selection [REDACTED]: NSPI issued an RFP for biomass supply on June 14, 2024. A total of [REDACTED] parties received the RFP; of those, [REDACTED] submitted an offer, while [REDACTED] others ([REDACTED]) requested terms of extension to their existing supply agreements with NSPI.

Given the low RFP turnout, we reviewed the RFP for barriers to participation. We identified two. First, the RFP indicates that suppliers “[w]ill enter into an agreement with NSPI for a preferred period not less than 2 year(s).” This is likely an unreasonable minimum timeframe for many suppliers. NSPI noted that [REDACTED] have indicated limited ability to offer anything beyond one year of supply. Moreover, NSPI’s RFP evaluation methodology does not actually include that “preferred period” in its “key selection criteria,” which specifies [REDACTED] factors unrelated to supply contract term. NSPI should revise future RFPs to encourage more offers; we include a recommendation on this point. Second, the RFP did

not specify the time period of NSPI's biomass supply need. We observed no references to 2024, 2025, or 2026 needs in the RFP. This lack of specificity reduces confidence in the RFP and can harm participation. We include a recommendation on this point as well.

Entering the RFP, NSPI had open positions of [REDACTED] GMT of primary biomass and [REDACTED] GMT of secondary biomass fuel in 2025, plus [REDACTED] GMT of primary biomass and [REDACTED] GMT of secondary biomass in 2026. [REDACTED] offer as provided by NSPI does not include key offer terms, including quantity of biomass supply or moisture content, indicating instead "TBD in contract" for these key terms. NSPI's ROA for this RFP, however, indicates [REDACTED] offered a "total volume to be committed" of [REDACTED] GMT of bark, [REDACTED] GMT of forest chips, and [REDACTED] GMT of roundwood for a two-year period.

[REDACTED] offer was the [REDACTED] offer received and thus had no direct comparators for evaluation. However, for 2025 supply, NSPI did compare [REDACTED] offer—notwithstanding our point above regarding the seemingly empty quantity and quality specifications in the original bid—to [REDACTED] existing biomass supply agreement with NSPI, which contained a clause²⁷² that allowed for extension through 2025. NSPI found that the more economic option was to extend the existing agreement with [REDACTED] at an estimated total cost of [REDACTED] million, which would save approximately \$[REDACTED]. Under the existing contract with [REDACTED] the contract extends automatically through the end of 2025 unless one of the parties provides written notice to terminate the contract.

For 2026 supply, NSPI noted that it had no competing offers to compare to [REDACTED] offer. Still, NSPI selected [REDACTED] 2026 offer at a total estimated cost of \$[REDACTED] million due to "the typical historical competitiveness of [REDACTED] pricing compared to other suppliers" and "the stability of [REDACTED] as a counterparty." NSPI noted the importance of this purchase to "hedge the risk of increasing prices for a portion of 2026 biomass fuel portfolio." NSPI acknowledged a concern we have long held, namely, that [REDACTED] interconnectedness with NSPI's biomass supply and management logistics gives [REDACTED] undue access to commercial information of its competitors:

Through biomass logistics services, [REDACTED] **will have access to certain information regarding other suppliers of biomass, including price.** Locking in the 2026 biomass supply with [REDACTED] now reduces the risk of [REDACTED]

[REDACTED] This is further supported by the pricing of [REDACTED] offers. [REDACTED] chips and bark continue to remain lowest cost currently contracted for 2025.

NSPI's decision to extend its existing contract with [REDACTED] through the end of 2025 was sound, as the extension option was demonstrably lower cost than [REDACTED] 2025 RFP offer. Regarding 2026 supply, NSPI's decision to pursue a contract with [REDACTED] was reasonable, as it represented the [REDACTED] RFP offer, allowed NSPI to secure [REDACTED] % of its open position for biomass fuel in 2026, plus a small amount ([REDACTED] GMT) of bark, and [REDACTED] pricing was competitive relative to NSPI's other primary fuel supply contracts.

²⁷² "[REDACTED] 2023 Biomass Supply Agreement," section 2.2.

On the last point, ██████ fully evaluated price for its forest chips (\$█████/MMBtu for ██████ GMT of the ██████ GMT primary fuel supply offered) was lower priced than any other primary fuel supply NSPI had under contract at that time. The remainder of ██████ primary fuel offer (█████ GMT of fuel log chips) had a fully evaluated price (\$█████/MMBtu) that was higher than any other primary fuel supply agreement in place at that time, other than ██████ fuel logs purchased in the first quarter of 2024 (and explained above). ██████ offer was for 2026 supply, and thus while NSPI's existing suppliers may have been providing primary fuel at lower evaluated costs, they were doing so in 2024 and 2025. Like ██████ those suppliers may have sought higher prices to supply primary fuel in 2026 (had they offered).

████████████████████ The FST approved the pursuit of the extension of the existing agreement with ██████ through 2025 and a new contract for 2026 supply on October 2, 2024. On October 18, 2024, neither agreement with ██████ was finalized. On that date, NSPI sought FST approval to purchase ██████ GMT of primary biomass fuel and ██████ GMT of bark from ██████ ██████ through extension of ██████ existing agreement for an approximate total cost of \$█████ million.

In the extension, ██████ sought price increases of ██████ for primary biomass and ██████% for bark.²⁷³ At these levels, ██████ primary biomass fuel fully evaluated price was \$█████/MMBtu and its secondary biomass fuel evaluated price was \$█████/MMBtu. The ROA noted that this purchase would bring total contracted bark volumes to ██████ GMT in 2025, materially closer to its projected consumption needs of ██████ GMT for the year. The purchase would also bring NSPI to an over-procured position for 2025 primary fuel, increasing the total volume under contract to ██████ GMT, above the expected consumption target of ██████ GMT. NSPI noted in its ROA that bark appeared in short supply for 2025 due to sawmill process improvements resulting in lower quantity of bark by-product, and competition from the ██████ business. The ROA noted that it had pursued discussion with several suppliers, and while offers to provide primary biomass fuel were plenty, bark offers were not. Moreover, when offers for bark were put forth, they were contingent on selection of substantial amounts of primary biomass fuel as well. The FST approved the ██████ extension, which was executed at the terms discussed in the ROA (though the date of the execution is not included in the ██████ contract extension).²⁷⁴ NSPI separately provided documentation demonstrating that the ██████ contract extension was executed on December 3, 2024.

████████████████████: On November 7, 2024, the FST approved the purchase of ██████ GMT of bark and ██████ GMT of primary biomass fuel from ██████ at a total estimated cost of \$█████. NSPI explained that it had been pursuing a longer-term supply agreement with ██████ since the June 2024 RFP, but had so far been unsuccessful due to ██████ insistence that any contract for 2025 biomass supply include ██████ GMT of primary biomass, far beyond NSPI's need. NSPI explained that it was able to reach agreement with ██████ to deliver these smaller amounts of primary and secondary biomass fuel in 2024, though NSPI assessed this purchase against its 2025 supply needs. ██████ offered bark was needed,

²⁷³ "██████████ - 20231231 First Amending agreement," item 2; "██████████ - 20241231 Second Amending Agreement," item 4.

²⁷⁴ "██████████ - 20241231 Second Amending Agreement."

as it would bring NSPI to █████ GMT of contracted supply (vs. a need of █████ GMT), while the primary biomass fuel was not needed (bringing NSPI's total contracted supply in 2025 to █████ GMT, █████ GMT above its then-target of █████ GMT). The fully evaluated prices of these supplies were \$████/MMBtu for the primary supply and \$████/MMBtu for the bark. Again, NSPI could only select the bark if it accepted the primary biomass fuel. One positive to this offer from █████ was that █████ was offering to deliver chips to PHB, rather than fuel logs (as was the case with the Q1 2024 supply contract). As noted before, approval was provided on November 7, 2024, and the contract (with terms matching the offer) was executed on November 15, 2024.²⁷⁵

On December 6, 2024, NSPI sought FST approval for a new agreement with █████ for █████ GMT of primary biomass fuel (████ GMT forest chips, █████ GMT fuel log chips) and █████ GMT of bark to be delivered in 2025 at a total estimated cost of \$████ million. NSPI's ROA noted that it successfully negotiated █████ original primary fuel offer quantity from █████ GMT to █████ GMT. The bark was needed and would bring NSPI's total contracted bark to █████ GMT, which was equal to NSPI's updated 2025 forecast need. The primary biomass fuel was not needed, and would result in an over-procured position of █████ GMT relative to NSPI's updated primary biomass fuel needs in 2025.

In addition to the supply surplus, NSPI also faced inventory storage limits on the portions of the PHB facility that is owned by NSPI. (Much of the land on site used for inventory storage is owned and used by PHP, not NSPI.) NSPI indicated in the ROA that PHP agreed to work with NSPI to optimize available space at the site to accommodate proposed volumes in 2025, while NSPI would seek to push biomass deliveries in 2025 to the latter portion of the year. NSPI also modeled an incremental \$████ in inventory management costs associated with █████ bark offering, which, due to "storage limitations at PHB," storing larger amounts of bark leads to "an increased risk of fire hazard" as was experienced in 2024 (and which we explain later in this chapter)." This incremental cost, which would be incurred through storing some bark adjacent to the PHB hopper, would require handling and reclaim. The ROA again noted that bark remained "scarce" for 2025 due to sawmill process improvements resulting in lower quantity of bark byproducts, increased bark consumption by sawmills, and downturn in the demand for lumber in Nova Scotia.

████ fully evaluated prices were \$████/MMBtu (forest chips), \$████/MMBtu (fuel log chips), and \$████/MMBtu (bark). The FST approved the transaction on December 9, 2024, and the contract with █████ was executed on December 24, 2024, with key terms matching the ROA.²⁷⁶

To better see these collective and incremental supply purchases, the following table shows NSPI's 2025 contracted volumes by supplier. NSPI's 2025 fuel needs come from the last ROA in 2024, the █████ contract for 2025 supply, which had the highest forecasted biomass consumption of any forecast observed. Also, in the table below, we are including the November 2024 █████ contract for █████ GMT of

²⁷⁵ "████ Biomass Amendment."

²⁷⁶ "████ Biomass Purchase Sale Agreement."

Figure VI-9: NSPI 2025 Biomass Fuel Portfolio (following Q4 2024 procurement)

Primary Biomass		
Supplier	Quantity (GMT)	Evaluated Price (\$/MMBtu)
Total Procured		
Forecasted Need		
Secondary Biomass		
Supplier	Quantity (GMT)	Evaluated Price (\$/MMBtu)
Total Procured		
Need		

The table above shows that in total, NSPI procured ██████ GMT of primary biomass fuel that was above its forecasted needs. To estimate the cost of this surplus, we used NSPI's \$/GMT evaluation price for its two highest-priced sources of supply (both found in ██████ 2025 agreement), weighting the price by volume to arrive at an average price of \$██████████. Applying this weighted-average price to the ██████ GMT of surplus primary fuel supply yields a total cost of \$██████████. For bark, NSPI procured ██████ GMT more than its forecasted need. Using the highest-priced supply's \$/GMT evaluation price during the Audit Period (██████████ \$██████████/GMT), the cost of this surplus was \$██████████. Collectively, the cost of the surplus biomass fuel totaled \$██████████.

NSPI's decisions appear to reflect the realities of the biomass fuel landscape in Nova Scotia. Suppliers were largely willing to provide secondary biomass fuel only if NSPI was willing to accept material volumes of primary fuel. This led to surplus purchases, particularly for primary biomass fuel, which imposed incremental costs on FAM customers. At the same time, the PHB unit's value has materially appreciated under the OBPS regime, which allows PHB to generate large OBPS credits that reduce costs for FAM customers. During the Audit Period, PHB generated \$[REDACTED] million in OBPS credits. PHB also contributes to NSPI's other environmental compliance efforts, including emissions and

renewable energy standards. The surplus fuel itself can also still be consumed at the PHB boiler, and consumption in 2025 was the highest in several years. NSPI has also taken steps to adapt to the challenges in procuring bark, including utilization of higher primary fuel blends in PHB's fuel mix.

VI.B.1.f. First Quarter 2025

NSPI entered into no new contracts for biomass supply in the first quarter of 2025.

VI.B.1.g. Second Quarter 2025

NSPI entered into one new contract for biomass supply in the second quarter of 2025. This is shown in Figure VI-10.

Figure VI-10: NSPI new biomass supply contracts (Q2 2025)

Supplier	Product	Quantity (GMT)	Term
	Primary Fuel Log Chips		
	Primary Forest Fuel Chips		
	Secondary Forest Biomass (Bark)		

In the second quarter of 2025, NSPI reported its new biomass fuel supply agreement with [REDACTED] with an effective period of January 1, 2026 through December 31, 2026.²⁷⁷ The contract, which was provided by NSPI, indicates that it was executed on January 1, 2026,²⁷⁸ which could not be the case, given the contract was reported in a quarterly FAM report several months prior. We include a recommendation that NSPI include execution dates for all contracts.

This contract related to the June 2024 biomass supply RFP, which we explained above in section VI.B.1.e, and represented the selected 2026 supply offer by [REDACTED]. Contract prices matched [REDACTED] original offer.²⁷⁹ Contract volumes matched evaluated volumes.²⁸⁰

VI.B.1.h. Third Quarter 2025

NSPI entered into no new contracts for biomass supply in the third quarter of 2025.

VI.B.1.i. Fourth Quarter 2025

NSPI entered into no "new" contracts for biomass supply in the fourth quarter of 2025. However, NSPI [REDACTED] its respective agreements with [REDACTED] [REDACTED] and [REDACTED]. This is shown in Figure VI-11.

²⁷⁷ NSPI Q2 2025 FAM Report, tab "Q3."

²⁷⁸ "[REDACTED] Biomass Supply Agreement."

²⁷⁹ "[REDACTED] Biomass Supply Agreement."

²⁸⁰ "[REDACTED] Biomass Supply Agreement."

Figure VI-11: NSPI new biomass supply contracts (Q4 2025)

Supplier	Product	Quantity (GMT)	Term
[REDACTED]	Sawmill Bark	[REDACTED]	[REDACTED]
	Biomass Roundwood/ Chips and Grindings	[REDACTED]	
[REDACTED]	Sawmill Chips	[REDACTED]	[REDACTED]
[REDACTED]	Sawmill Bark	[REDACTED]	[REDACTED]
[REDACTED]	Sawmill Chips	[REDACTED]	[REDACTED]
[REDACTED]	Sawmill Bark	[REDACTED]	[REDACTED]

NSPI issued an RFP for biomass supply on July 4, 2025 to [REDACTED] recipients, seeking bark, chips, and fuel log biomass fuel for 2026 supply. [REDACTED] suppliers submitted offers: [REDACTED]. All [REDACTED] suppliers offered primary biomass fuel, while [REDACTED] of those [REDACTED] ([REDACTED] offered bark. All [REDACTED] bark offers were “bundled” with primary fuel offers, meaning they could not be selected without also committing to selection of primary biomass fuel commitments.

NSPI forecasted a remaining open position of [REDACTED] GMT of bark and [REDACTED] GMT of primary biomass fuel, when accounting for existing inventories and the 2026 supply contained in the [REDACTED] contract executed in the second quarter of 2025. To evaluate offers, NSPI followed its normal course and evaluation methodology, but supplemented that analysis by calculating the “bundled” price of each offer that included both bark and primary biomass fuel. This was a reasonable step, given the offers: the lowest cost chips were offered by [REDACTED], but that offer was bundled with the highest cost bark. NSPI selected the [REDACTED] lowest-priced bundled offers: [REDACTED] for [REDACTED] GMT of bark and [REDACTED] GMT of primary biomass and [REDACTED] for [REDACTED] GMT of bark and [REDACTED] GMT of primary biomass. With this procurement, NSPI would have small remaining open positions for 2026 ([REDACTED] GMT of bark and [REDACTED] GMT of primary biomass). [REDACTED] was the next best offer, but required NSPI to contract for [REDACTED] GMT of primary biomass fuel in order to receive any bark, an offer NSPI declined (though NSPI indicated it continued discussions with both [REDACTED] and [REDACTED]). The proposed transactions, which had a collective estimated cost of \$[REDACTED] million, were approved on September 19, 2025. Both the [REDACTED] and [REDACTED] contracts were executed as amendments to their respective existing agreements. The [REDACTED] contract matched [REDACTED] offer.²⁸¹ The [REDACTED] contract was executed with terms that matched [REDACTED] offer, though again did not contain an execution date.²⁸²

Later, in December 2025, following conclusion of ongoing negotiations with [REDACTED] NSPI put forth a recommendation to contract with [REDACTED] for [REDACTED] GMT of primary biomass fuel and [REDACTED] GMT of bark

²⁸¹ “[REDACTED] - 20251231 Amending Agreement to 20240101 Biomass Agreement,” item 2; ROA SF0272 and SF0277 Bid Package, PDF page 147.

²⁸² “[REDACTED] - 20251231 3rd Amendment to 20230122 Biomass Agreement.”

to be delivered in 2026. The total estimated contract value was \$ [REDACTED] million. The volumes would bring NSPI's contracted volume for bark to [REDACTED] GMT (vs. a forecasted need of [REDACTED] GMT) and [REDACTED] GMT of primary biomass fuel (vs. a forecasted need of [REDACTED] GMT). In assessing this option, NSPI noted that it did not expect [REDACTED] to provide the contractual volumes in 2026 based on NSPI's experience with [REDACTED] as a supplier in 2025. NSPI noted that [REDACTED] 2025 deliveries were "challenged by several factors affecting the biomass market," including "the provincial fire ban which impeded harvesting during summer 2025," "a blockade limiting access to lands due to a dispute with First Nations in 2025," and "extensive damage to NS Power's bark conveyor system which occurred early in 2025." (We address the bark conveyor system issue later in this chapter.) We confirmed that [REDACTED] fuel log deliveries in 2025 (just under [REDACTED] GMT) were well below [REDACTED] contracted volumes ([REDACTED] GMT).²⁸³ NSPI compared the [REDACTED] offer's bundled, fully evaluated price of \$ [REDACTED]/MMBtu to the only other active offer it had at that time, which was [REDACTED] and which evaluated at a bundled, full evaluated price of \$ [REDACTED]/MMBtu. The transaction was approved on December 20, 2025, and the contract amendment (with prices and quantities that matched the evaluated offer²⁸⁴) was executed on December 23, 2025.²⁸⁵

VI.B.8. Other Biomass Fuel Contracts and Procurement

Biomass advisory services: On May 22, 2024, NSPI retained [REDACTED] (" [REDACTED] ")²⁸⁶ to provide biomass fuel market advisory services for assistance "in identifying biomass fuel market opportunities for short to medium term fuel supply" to PHB and to support evaluation opportunities. Under the agreement NSPI pays [REDACTED] an hourly rate for services.²⁸⁷ [REDACTED] provided four reports to NSPI during the Audit Period.

Forest Sustainability Agreement DNRR Funding under *Forests Act*: NSPI entered into two separate agreements with the Minister of Natural Resources and Renewables ("DNRR") under the *Forests Act*²⁸⁸ that allows NSPI to receive funding from DNRR to support NSPI's operation of a silviculture program.²⁸⁹ Under the agreements, NSPI received \$ [REDACTED] in 2024 and \$ [REDACTED] in 2025. The 2024 funds were allocated to FAM customers in January 2025; the 2025 funds are to be allocated in 2026.

Additional fuel handling cost to mitigate pile combustion: On October 30, 2024, PHP personnel contacted NSPI personnel by email indicating that NSPI's "bark pile has been developing hot spots and smoldering for over 6 weeks." PHP made reference to prior "incident reports" by PHP to NSPI

²⁸³ [REDACTED] Biomass Purchase Sale Agreement," item 4.

²⁸⁴ [REDACTED] Biomass Purchase Sale Agreement," item 4.

²⁸⁵ [REDACTED] Biomass Purchase Sale Agreement."

²⁸⁶ [REDACTED] - 20240522 Consulting Agreement."

²⁸⁷ [REDACTED] - 20240522 Consulting Agreement," Schedule A.

²⁸⁸ Available at: <https://nslegislature.ca/sites/default/files/legc/statutes/forests.htm>.

²⁸⁹ "NSDNRR - 20240718 Forest Sustainability Agreement," "NSDNRR - 20250731 Forest Sustainability Agreement."

informing NSPI of this issue. PHP noted that in managing the issue to date, PHP's efforts had gone beyond the contractual scope associated with its role in operating and maintaining the plant, and that going forward, "more proactive and drastic measures are required to prevent the reoccurrences (sic)." PHP proposed a scope of work to mitigate the issue that included moving portions of the bark pile and allowing for ventilation, suggesting the work be done for one week, then reassessed, at an estimated cost of \$26,000. The NSPI team moved quickly to get this issue addressed, proposing internal approval for this expense and receiving it on the same date as PHP's email (October 30, 2024).

Over the next several weeks, PHP would continually provide updates on the work being done and inform NSPI of whether work would need to continue for the subsequent week. NSPI considered and approved all such requests. Work was considered complete on December 18, 2024. In total, costs incurred and paid by NSPI were \$ [REDACTED]. We offer the following observations from this incident.

First, in the early days of this incident, NSPI personnel demonstrated diligence in getting relevant information and updates from PHP, including evidence of the overall work plan. Second, the work associated with this cost appears necessary and a matter of safety, not only preservation of NSPI's fuel supply and PHB's operations. PHP noted that its on-site emergency personnel and equipment were dispatched throughout the initial six-week period addressing localized hot spots on the pile. Third, NSPI's estimate for lost bark associated with this incident is no more than two tonnes, though NSPI warned that any potential loss of bark inventory cannot be quantified with accuracy. We found no additional evidence on this point. Bark inventory adjustments over the Q3-Q4 2024 period were a net increase of [REDACTED] GMT.

We also observed that NSPI personnel reasonably questioned whether the costs associated with this event should be paid by PHP, rather than NSPI, given PHP's roles and responsibilities under its operations and maintenance services agreement for PHB. PHP is required under this agreement to:

Respond in a commercially reasonable manner to hot spots and open fires in the storage piles; Biomass Fuel that is hot, smoldering or on fire shall be separated from the Biomass Fuel storage piles or otherwise handled in a prudent manner. NSPI shall cooperate with PHP to use or remove hot Biomass Fuel expeditiously upon request.²⁹⁰

In defending the appropriateness of paying this cost (and passing it to FAM customers), NSPI indicated during the audit that, during this event, the scope of required services expanded beyond a routine and commercially reasonable response to isolated hot spots to a concerted effort to address large developing hot zones in order to prevent imminent fire and potential major damage to the bark pile. NSPI noted that section 2.04(g) further requires it to cooperate with [REDACTED] to use or remove hot biomass fuel expeditiously upon request. NSPI stated that PHP satisfied its obligation under section 2.04(g) by exhausting commercially reasonable efforts to manage the developing situation, while NSPI satisfied its obligation under section 2.04(g) by assuming responsibility for the incremental costs associated with

²⁹⁰ "PHP - 20240328 NSPI Biomass Fuel Handling 2024 Services Agreement," section 2.04 (g).

expeditiously moving the hot biomass fuel. NSPI also indicated that section 2.03 of the operations and maintenance services agreement requires PHP to perform its obligations in accordance with “reasonable Industry Standards,” which NSPI stated are generally understood to reflect the practices and performance expected under ordinary operating conditions.

The contract language does not explicitly indicate NSPI will be responsible for incremental costs, only that NSPI will cooperate in either consuming that fuel or removing it. Moreover, cooperation from NSPI is necessary since it is NSPI’s fuel—if PHP was to remove that fuel unilaterally, it would be an act of destruction or theft. Should the Board consider a disallowance for these costs, we agree with NSPI that the cost of the event is \$ [REDACTED] with no demonstrable loss of inventory.

Going forward, NSPI indicated that it has implemented improvements associated with inventory management to reduce the likelihood of similar incidents in the future. This includes a revised storage configuration that uses smaller and lower height biomass fuel storage piles, rather than fewer larger piles, in order to improve ventilation and reduce compaction in the piles.

Revisions to, Extension of Shared Services Agreement with PHP: During the Audit Period, NSPI remained subject to the “Shared Services and Steam Supply Agreement,” or “Shared Services Agreement,” which was executed by PHP and NSPI on September 28, 2012.²⁹¹ NSPI also continued to employ the “energy balance process” to account for fuel consumption and inventory levels for both NSPI and PHP in procuring and feeding biomass fuel into PHB’s boiler. The energy balance process is a thermal energy balance determination of the amount of the total steam energy produced that was used for paper mill processes and used to generate electricity. The energy balance process takes the known amount of primary biomass, secondary biomass, sludge,²⁹² and natural gas consumed in the boiler and calculates PHP’s share of each fuel’s consumption, with the remainder allocated to NSPI. The process is a complicated one: the boiler is fed by three separate fuel “piles,” two containing a mix of fuels, with commingling of PHP fuel and NSPI fuel either in the inventory piles, the boiler, or both. In each of our prior two audit reports, we have recommended that the energy balance process be codified into the Shared Services Agreement.²⁹³

On March 7, 2025, NSPI and PHP executed an amendment to the Shared Services Agreement. Among other changes, the edits introduce a new Schedule 13, titled “Energy Balance Process.” Schedule 13 explains that using the “Energy Balance Excel Worksheet” (“Energy Balance Worksheet”), NSPI will calculate the energy balance attributable to PHP and to NSPI. The Energy Balance Worksheet is not part of the Shared Services Agreement, but instead will reside outside the agreement and will be modified as needed to improve the accuracy of the Worksheet, subject to both parties’ approval and working reasonably and in good faith. Using data from PI, the Worksheet estimates the total energy production

²⁹¹ “PHP - 20120928 Shared Services and Steam Supply Agreement - PHP and NSPI.”

²⁹² Sludge is defined as dewatered organic material generated from [PHP’s] effluent treatment plant.

²⁹³ 2022-2023 Bates White Audit Report, Recommendation VI-2; 2020-2021 Bates White Audit Report, Recommendation V-2.

leaving the boiler and the steam consumption at PHP (for its industrial processes) and PHB (for electricity generation). Fuel moisture content of NSPI's bark, NSPI's chips, and PHP's bark and chips is determined through daily samples, and tracked. All natural gas consumed is assumed to be purchased and consumed by PHP, unless specifically purchased by NSPI for its own use. NSPI and PHP also developed an Energy Balance Flow Diagram, which is an Excel-based file that illustrates how the Energy Balance process works.

The concept of the energy balance process is simple: PHP [REDACTED], while NSPI [REDACTED]. The execution is not simple. In delving into the now-codified energy balance process, we established some key facts:

- There are three piles that feed the boiler:
 - The “chip silo” contains chips purchased by NSPI from its suppliers (including PHP), plus any additional chips contributed by PHP.
 - The “blended pile” is primarily bark and contains a blend of fuel purchased by NSPI (including from PHP) and any additional bark contributed by PHP.
 - The “wood room” contains PHP's bark, which is the byproduct of its paper-making process.
- PHP's “sludge” is also fed into the boiler. Sludge is a byproduct of the paper-making process.
- Natural gas may also be added to the boiler and can be done by NSPI or PHP independently.
- PHP contributes 100% of the sludge and wood room bark.
- NSPI knows its recorded biomass fuel inventory at the beginning of the month. As the month goes on and fuel is consumed, NSPI does not update its inventory. That is done at the conclusion of the energy balance process at the end of the month.
- NSPI does not know PHP's day-to-day fuel inventory, nor the cost or quality of that inventory, though does obtain PHP inventory records for quarterly reconciliation purposes. NSPI indicated that in addition to fuel supply volumes PHP provides NSPI under their supply contracts, PHP can contribute additional, incremental biomass fuel to the chip silo or blended pile beyond its contractual obligations. We observed no evidence that such incremental contributions occurred during the Audit Period.

During the month, biomass fuel from all three piles, plus sludge and occasional natural gas, are fed to and consumed in the boiler. Steam produced is sent to PHP for its industrial process, the power

generator, or both. The moisture content of the fuels fed to the boiler vary, as does the blended fuel moisture content. This impacts the efficiency of the boiler and cost of the steam produced.

- The energy balance process, which occurs at the close of the month, is the basis for any debits or credits for PHP's commercial relationship with NSPI, as well as the basis for updating NSPI's biomass fuel inventory.

In memorializing the energy balance process into the Shared Services Agreement, NSPI revised the process in at least two key ways. First, the process changed how natural gas consumption would be allocated. Natural gas consumed during start-up periods for the PHB boiler, before steam is exported to PHP and before the steam turbine generator begins producing electricity, would be specifically accounted for and attributed solely to NSPI. Second, in each hour, NSPI would determine if the total energy (in gigajoules) produced by natural gas consumed in that hour exceeded the energy (in gigajoules) consumed in the production of electricity by the generator, and if so, to allocate all such excess natural gas consumption to PHP. PHP continues to purchase natural gas for consumption in the PHB boiler at its own expense, while NSPI purchases natural gas for consumption in the boiler as well. The logic is reasonable, as PHP pays 100% of the cost of its natural gas purchases and should get credit in the energy balance process for that natural gas—such credits serve to reduce the amount of biomass fuel that is assigned to PHP for cost allocation purposes. For any day in which PHP is allocated a non-zero natural gas balance, that allocation is done at a daily average gas price and generates a payment due from PHP.

Second, PHP introduced a new two-step process for allocating biomass fuel between the parties.²⁹⁴ In the first step ("Step 1"), fuel is first allocated to PHP to (theoretically) "dry" the sludge PHP contributes to the boiler, such that the sludge plus the allocated biomass fuel in Step 1 produces a blend with an average moisture content of █%. Sludge can have moisture content upward of █%, and thus Step 1 allocates a mix of biomass fuel with sufficiently low moisture content to bring the average of the blend down to █%. As noted earlier, there are three separate inventory piles that feed the boiler— PHP's wood room bark, NSPI's blended pile (bark), and NSPI's chip silo (chips). Step 1 proceeds by first allocating all natural gas attributable to PHP and wood room bark consumed in the boiler. Natural gas provides energy but is considered moisture-free, and wood room bark has lower moisture content than sludge. As such, both serve to lower the overall moisture content of the sludge-wood room bark-natural gas blend. The energy balance process then allocates a mix of bark (from NSPI's blended pile) and chips (from NSPI's chip silo) to mix until the average moisture content of the overall blend is reduced to █%. Once that moisture level is reached, the process moves on to Step 2.

²⁹⁴ Prior to April 2024, the energy balance and fuel allocation procedure treated sludge consumption in excess of either █% of daily biomass or greater than █ tonnes/day as contributions to PHP fuel blend moisture and required PHP fuel to be blended to a moisture level equal to that provided by NSPI.

The second step (“Step 2”) begins by comparing (1) the amount of energy (in gigajoules) produced by the fuel from Step 1 to (2) the amount of energy demanded (in gigajoules) by PHP during the month to produce the steam that was fed to PHP’s industrial processes. If (1) is less than (2), the energy balance process determines a mix and volume of biomass fuel that meets PHP’s remaining demand. To translate this energy demand into biomass fuel tonnage and costs, the energy balance process must select a “target” moisture content for PHP’s fuel. Step 2 does so on the basis of the average moisture content of the fuel fed to the boiler in the month. If the monthly blended fuel moisture is █% or higher, PHP’s average moisture content requirement is █%. If the monthly blended NSPI fuel moisture is below █%, then the blended fuel moisture requirement for PHP equals NSPI’s monthly blended fuel moisture (though is subject to a █% minimum). This means that Step 2’s target moisture content is subject to a floor (█%) and a ceiling (█%). To finalize allocations between NSPI and PHP, the Worksheet uses an “iterative process...where bark and chip allocations to [PHP] are adjusted to ensure they meet the fraction of total energy consumed by [PHP] and the fuel blend moisture requirements for [█] which as was already explained, will be between █% and █%. This is done manually by NSPI staff. When the PHB generator is offline, PHP’s average moisture requirement is █%. As it relates to biomass fuel, the energy balance process assigns “costs” between PHP and NSPI by adjusting NSPI’s inventory levels and assigning debits or credits on PHP’s invoices.

As an initial matter, NSPI has been fully responsive to our recommendation to codify the energy balance process in the Shared Services Agreement: the energy balance process has been brought to greater light. It should be noted that the Energy Balance Worksheet is not included in the Shared Services Agreement. NSPI indicated that this was intentional since the Worksheet is complex and technical in nature. NSPI stated that any modifications to the Worksheet require agreement by NSPI and PHP, and that any changes to the energy balance process can be made via the Shared Services Agreement. We agree with this characterization: the Energy Balance Worksheet is dense, complex, and highly technical. It does not allow for simple verification of results. The Energy Balance Workbook is replete with price data, moisture testing results, engineering assumptions, and complex calculations. Nevertheless, we reviewed Audit Period results and offer the following.

The costs at issue are substantial. Pursuant to the energy balance process, NSPI was assigned \$█ million of costs in 2024 and \$█ million in 2025. NSPI did not provide the precise cost data for PHP’s allocation. However, PHP did provide the total blended pile (bark) and chip silo (chips) allocation to PHP, which totaled █ GMT of chips and █ GMT of bark. NSPI also noted that the “price” applied to all allocated quantities of these fuels to PHP is the effective contractual price paid by NSPI to PHP under their existing biomass fuel supply agreement. During the Audit Period, NSPI paid \$█/GMT for fuel log chips, \$█/GMT for forest chips, and \$█/GMT for bark.²⁹⁵ Applying these prices to the known allocated quantities of biomass fuel to PHP yields between \$█ million and \$█ million, depending on whether the price for fuel log chips or forest chips is used.

²⁹⁵ “PHP - 20230118 2023 Biomass Supply Agreement.”

NSPI has appears to have applied the energy balance process consistent with the Shared Services Agreement as revised. We observed, for example, that in the [REDACTED] months where NSPI's total blended fuel moisture was [REDACTED] % or less, PHP's moisture target on which its cost allocation is based was [REDACTED] %, while in the [REDACTED] months NSPI's total moisture was [REDACTED] % or above, PHP's target was [REDACTED] %. We also observed NSPI applying inventory adjustments to its own inventories and credits and debits to PHP following the completion of the monthly energy balance.

We do have a few concerns with the energy balance process as codified and as carried out during the Audit Period. First, the "Step 1" moisture target, which is set at a fixed [REDACTED] %, is rigid, and that rigidity could lead to outcomes that unduly favor (or disfavor) PHP, relative to FAM customers. Historically, the energy balance process required PHP to balance its fuel to an average moisture content of [REDACTED] %, a value that was determined by [REDACTED] in 2013 as the moisture content that would optimally allow the boiler to produce steam output of 60 kg/second, which was the pressure needed to meet PHP's industrial demand plus NSPI's ability to produce maximum electricity on biomass fuel alone.²⁹⁶ In 2020, the parties adjusted this value down to [REDACTED] %, reasoning that because the PHB generating unit was dispatched economically and no longer as a "must-run" unit (as was the case in 2013), there was no need for the boiler to produce 60 kg/second.²⁹⁷ Moreover, NSPI noted that the observed moisture content of the fuel available in the province had materially increased, making a moisture target of [REDACTED] % unrealistic.²⁹⁸ Instead, [REDACTED] kg/second would suffice, and thus the parties engaged [REDACTED] to update their study with a target steam output of 50 kg/second.²⁹⁹ [REDACTED] determined that an average moisture content of [REDACTED] % would allow for 50 kg/second of steam output.³⁰⁰

We took no issue with this change in a prior audit report. However, in the current Audit Period, biomass fuel moisture was *down*. Average moisture content for biomass fuel fed to the PHB boiler was [REDACTED] % in 2024 and [REDACTED] % in 2025, the lowest two annual values observed over the 2019-2025 period. (Average moisture content from 2019-2023 averaged [REDACTED] %, and reached as high as [REDACTED] % in 2022.) During this Audit Period, low moisture content primary biomass fuel was plentiful (high moisture content secondary biomass was not) and NSPI successfully transitioned to a higher percentage of primary biomass fuel in its boiler. Further, the impact of the OBPS program on the economics of PHB was to make PHB highly economic due to the large OBPS credits it generates. NSPI sought to operate PHB at as high a capacity factor as possible due to these economics, meaning PHB was operating similar to a "must-run" resource.

Under these conditions, it may no longer be the case that a [REDACTED] % moisture target is unrealistic, and that a higher moisture target ([REDACTED] %) is warranted. Then again, the OBPS regime may change again, and

²⁹⁶ 2022-2023 Bates White Audit Report, page 154.

²⁹⁷ 2022-2023 Bates White Audit Report, page 154.

²⁹⁸ 2022-2023 Bates White Audit Report, page 154.

²⁹⁹ 2022-2023 Bates White Audit Report, page 154.

³⁰⁰ 2022-2023 Bates White Audit Report, page 154.

bark supply may rebound, in which case those conditions may be restored. The issue here is the rigidity of the moisture target determination. If too high, the allocation of fuel in Step 1 will be unduly too inexpensive. And if too low, PHP's share will be unduly too expensive. We are not recommending a specific remedy in this case. However, we do include a recommendation that NSPI consider ways to account for the dynamism in PHB's relative economics and the biomass fuel supply realities in the province to prevent instances of unduly high or low payments by PHP under Step 1.

Our second concern involves Step 2, which subjects PHP's moisture target to a collar (a combination of a floor of █% and a ceiling of █%). In our view, the application of a collar should be reconsidered. Assume, for example, the fuel feeding the boiler in a given month had an average moisture content of █%. Under the energy balance process, PHP's target moisture content would not be █%, but would be subject to the moisture target floor of █%. The cost of producing a blend with █% moisture is higher than that of a █% moisture, so in this case, PHP would be shielded from additional cost. Assuming a total average moisture content of █% would have the opposite effect: PHP's moisture content would be subject to the ceiling of █%, meaning PHP would be charged more than it otherwise should.

During the Audit Period, we note that PHP's Step 2 moisture target was subject to the floor of █% in █ of 24 months and was subject to the ceiling of █% in just █ months. Removing or relaxing the collar would address this concern. We recommend NSPI consider doing so.

Our third concern with the energy balance process is that it allows PHP to carry "negative" balances on its ledger with NSPI indefinitely and penalty-free. This concern is limited to the parties' treatment of bark volumes. Specifically, for bark volumes, if PHP is found to have consumed bark in such volumes that it "owes" NSPI for consumption of bark provided by NSPI, NSPI requires PHP to provide physical bark to make up that deficit. This differs from its treatment of chip deficits, which NSPI requires be compensated via invoice credits. NSPI explained that while the Shared Services Agreement does not prescribe a remedy for these deficits, NSPI seeks physical bark from PHP due to the scarcity of bark in the province and PHP's purported advantage in procuring bark relative to NSPI. This is a reasonable approach, in our view. However, we did observe PHP's bark deficit steadily accrue in 2025, from an initial deficit of █ GMTs of bark at the end of January 2025 to █ GMTs of bark by the end of the Audit Period. NSPI informed us that it received █ GMTs of bark from PHP in 2026 to address this deficit, and later confirmed that the entire deficit was made up as of May 2026. Regardless, the energy balance process and Shared Services Agreement does not contain any interest payments for bark deficits carried forward. This contrasts directly with FAM balances, which accrue interest at NSPI's weighted-average cost of capital. We recommend NSPI consider ways to capture the time value of these bark deficits.

Our fourth concern relates to the price of chips assumed by NSPI in its credits and debits with PHP. The price of chips used in the energy balance process is based on the proportions of forest chips and fuel-log chips delivered in the month of the energy balance calculations. This is appropriate, as NSPI

receives two types of chips from PHP under its biomass supply agreement (\$■/GMT for fuel log chips and \$■/GMT for forest chips). However, to the extent that PHP's chip deficit exceeds the chip volumes delivered by PHP (such that NSPI burns chips from other suppliers to serve PHP's industrial energy demand), PHP should be charged the blended cost of the chips in NSPI's inventory for those incremental volumes, not PHP's contractual rate for chips (which is often lower). This would ensure a fairer allocation. We include a recommendation to this effect.

VI.B.9. Contract Actions

VI.B.9.a. Force Majeure

NSPI reported no *force majeure* actions or issues related to biomass fuel during the Audit Period.

VI.B.9.b. Amendments and Extensions

We address contract amendments and extensions in sections VI.B.7 and VI.B.8 above.

VI.B.10. NSPI's Process for Biomass Fuel Receipt Information

NSPI uses the Aligné database in tracking biomass deliveries. NSPI receives all biomass deliveries by truck. Upon arrival, deliveries are weighed using WeighWiz, which is a commercially-available weigh scale system for truck deliveries. Upon capturing the weight of the delivery, as well as the type of biomass fuel (e.g., wood chips), vendor, and delivery location, the information is automatically transferred to the Log Inventory and Management System ("LIMS"), which is an off-the-shelf software program for managing timber and wood products that possesses the ability to track procurement, contractor payables, contract management, inventory, consumption, and accounting. The LIMS system is queried on a weekly basis to summarize this information, and the Senior Contract Administrator of biomass compares it against vendor invoices. When the vendor invoices are received, the delivery information is entered into Aligné. Once the fuel has been recorded in Oracle, the Aligné Fuels Administrator/Specialist indicates on the invoice that the receipt has been executed, generally by writing the purchase order and receipt numbers on the invoice. This information is sent to Accounts Payable for payment.

NSPI also uses a Senior Contract Administrator for Biomass, who has responsibility for field contract administration activities associated with biomass supply. The Senior Contract Administrator's primary activities focus on management of the biomass supply contracts and securing adequate biomass inventory. Additional responsibilities include invoice processing and verification of all related information on quality and quantity for biomass received, as well as input of certain data into Aligné.

On April 25, 2025, Aligné became unavailable due to the cyber event. It would remain unavailable until October 30, 2025, at which point it became available to a limited number of users to allow for testing of Aligné and backfilling of data recorded since April 25, 2025 into Aligné. On November 24,

2025, Aligné became available to more users, but as of the end of the Audit Period, Aligné was still in the process of being backfilled, and NSPI did not anticipate relying fully on Aligné Fuels until the end of the second quarter of 2026. The cyber event did not impact Aligné's historical database (pre-April 25, 2025 data), which was housed on off-site servers.

VI.B.11. Quantity and Quality Control of Solid Fuel

NSPI receives all biomass deliveries to the Port Hawkesbury plant by truck. Trucks are weighed as they enter the plant (with a full cargo) and as they exit (empty), with the delta being recorded as the weight of the delivery.³⁰¹ As noted above, the weight and delivery data are automatically transferred to LIMS and compared against vendor invoices on a weekly basis by the Senior Contract Administrator of biomass.

The biomass plant has two truck dumpers—one for primary biomass fuel (wood chips) and another for secondary fuel (bark). ERM determines the fuel blend, and the plant personnel are responsible for blending the fuels. As part of its services agreement with NSPI, PHP collects and analyses quality samples of biomass onsite for moisture content, fuel sizing, fuel type, and fuel quality.³⁰² On a quarterly basis, samples are also sent to [REDACTED] for testing of a variety of quality metrics, which are done in compliance with the American Society for Testing and Materials ("ASTM") standards.³⁰³

VI.B.12. Contract Compliance

VI.B.1.j. Contract Quantities

NSPI received biomass fuel from [REDACTED] entities during the Audit Period: [REDACTED]
[REDACTED] The tables below show, for each supplier, the total contracted minimum volume, total received volume, and the resulting overage or underage for each biomass product. Figure VI-12 shows this data for 2024.

³⁰¹ NSPI Fuel Manual Version 14, Link 10 "Biomass Fuel Procurement Quality Assurance for Sampling and Analysis," page 4.

³⁰² [REDACTED] Agreement for Ops and Maintenance Services Jan 2021.pdf," section 2.04 (as subsequently extended by [REDACTED] Extension Agreement for Ops and Maintenance Services Agreement.") See also, NSPI Fuel Manual Version 14, Link 10 "Biomass Fuel Procurement Quality Assurance for Sampling and Analysis."

³⁰³ NSPI Fuel Manual Version 14, "Biomass Fuel Procurement Quality Assurance for Sampling and Analysis."

Figure VI-12: 2024 Biomass Volumes Received from Suppliers vs. Contractual Volumes

Counterparty	Product	Contractual Volume (GMT)	Actual Volume (GMT)	Overage or Underage (GMT)
	Bark			
	Bark			
	Forest Chips			
	Fuel-Logs			
	Bark			
	Sawmill Chips			
	Forest Chips			
	Bark			
	Forest Chips			
	Fuel-Log Chips			
	Bark			
	Sawmill Chips			

Figure VI-12 shows that NSPI received a total of [REDACTED] GMT of primary biomass fuel during 2024 from [REDACTED] suppliers: [REDACTED]. Overall, NSPI received [REDACTED] in excess of contractual minimums, or [REDACTED]%. In all but one case, NSPI received volumes that exceeded contractual minimums. [REDACTED] was the largest supplier of primary biomass fuel, providing [REDACTED]% of all such fuel received. [REDACTED] also provided [REDACTED]% more primary biomass fuel than its contractual minimum, the largest such overage in 2024 in terms of the physical amount ([REDACTED] GMT).

Regarding secondary biomass, NSPI received [REDACTED] GMT less fuel than contracted, an underage of [REDACTED]%. All [REDACTED] suppliers provided bark in 2024, with [REDACTED] being the largest provider ([REDACTED]% of all bark received). Of the [REDACTED] suppliers, only [REDACTED] met contractual minimums, with [REDACTED] providing [REDACTED] GMT above its minimum of [REDACTED] GMTs. [REDACTED] had the largest deficiency, providing just [REDACTED]% of its contracted minimum, an underage of [REDACTED] GMTs. Overall, across all fuels, [REDACTED] ([REDACTED]%) and [REDACTED] ([REDACTED]%) were NSPI's largest suppliers.

We noted one instance in 2024 when one of NSPI's suppliers ([REDACTED]) delivered a volume of bark in January 2024 that exceeded a limit set in a supply agreement that was executed in the prior audit period. NSPI reviewed the issue internally, notified the supplier, and agreed with the supplier to allow for the excess volume and pay the same, pre-existing rate for that excess volume (which totaled [REDACTED] GMT). NSPI noted internally that the bark was economic, and the delivery data for 2024 shows that this overage was helpful in minimizing overall bark underdeliveries experienced during the year.

Figure VI-13 shows this data for 2025.

Figure VI-13: 2025 Biomass Volumes Received from Suppliers vs. Contractual Volumes

Counterparty	Product	Contractual Volume (GMT)	Actual Volume (GMT)	Overage or Underage (GMT)
	Bark			
	Bark			
	Forest Chips			
	Fuel-Logs			
	Bark			
	Sawmill Chips			
	Forest Chips			
	Bark			
	Forest Chips			
	Fuel-Log Chips			
	Bark			
	Sawmill Chips			

Figure VI-13 shows that NSPI received █████ GMT of total biomass fuel in 2025 from the █████ suppliers (only █████ did not provide 2025 supply). █████ (████%) and █████ (████%) were again NSPI's two largest suppliers. NSPI received █████ GMT of primary biomass fuel during 2025 from █████ suppliers, which was █████ percent lower than the collective annual contractual volumes. █████ suppliers (████████ provided more supply than contracted, but that overage was more than outweighed by lower-than-contracted deliveries from █████ (████ GMT) and █████ (████ GMT).

Regarding secondary biomass, NSPI received █████ percent less secondary biomass (████ GMT) than its collective contracted volumes (████ GMT). All █████ suppliers provided less than contract minimums, with █████ again driving the largest deficit (████ GMT, or █████% below contracted minimums).

In 2025, there were multiple factors that impacted biomass supply and deliveries. First, summer wildfires and fire risk conditions triggered restrictive provincial regulatory and legal steps, such as “woods bans,”³⁰⁴ which according to NSPI's consultant █████ led to “widespread operating restrictions and diversion of significant harvesting capacity toward fire-suppression results.” Second, new tariffs announced in 2025 by the U.S., a key export market for provincial lumber, harmed demand and sawmill economics along with it, leading to increased downtime and less output.

A third factor occurred on March 1, 2025, when a heavy equipment vehicle working at the PHB site struck the radial stacker conveyor structure that conveys delivered secondary biomass fuel from trucks to PHB's inventory piles. As a result of the incident, NSPI would only be able to accept bark deliveries from

³⁰⁴ Tourism Nova Scotia, “Wildfire Prevention Measures – Restrictions on Activities in the Woods,” August 5, 2025, available at: <https://tourismns.ca/news/intouch-blog/wildfire-prevention-measures-restrictions-activities-woods>.

self-unloading tractor-trailer trucks, a limitation that was in place until September 24, 2025. Self-unloading trucks are not standard or otherwise required by NSPI for its suppliers, and NSPI confirmed that suppliers that were unable to secure access to self-unloading trucks were unable to deliver bark to PHB. [REDACTED] was most impacted and indicated to NSPI that because of this issue, it could not deliver its bark; instead, it sold [REDACTED] GMT to other customers. As for the conveyor, NSPI commissioned a study by [REDACTED] to assess the damaged structure and develop options. [REDACTED] put forth three options ranging from refurbishment to demolition and complete replacement, with an estimated cost ranging from \$ [REDACTED] million to \$ [REDACTED] million.

NSPI has explained that liquidated damages clauses associated with underdelivery of fuel is not found in their biomass fuel supply contracts due primarily to biomass fuel being a derivative byproduct, meaning [REDACTED] is reliant on fuel that is subject to pricing and availability impacted by demand for the primary wood products. We have observed no evidence suggesting that absence of delivery-related damages is industry standard. Just one of NSPI's biomass supply contracts during the Audit Period contained penalties for over- or under-delivered quantities relative to annual minimum or annual quantities specified therein. [REDACTED] contract specifies that if [REDACTED] delivered less than its annual quantities of either primary or secondary biomass fuel, [REDACTED] would pay damages equaling \$ [REDACTED]/GMT for undelivered bark and \$ [REDACTED]/GMT for undelivered chips in a given year unless otherwise excused by the contract.³⁰⁵ As shown in the tables above, [REDACTED] met its targets for primary fuel but underdelivered by [REDACTED] GMT in 2024 and [REDACTED] GMT in 2025, for a total underdelivery of [REDACTED] GMT. This corresponds to a damages amount of \$ [REDACTED]. However, no damages were paid, as NSPI stated that [REDACTED] underdeliveries were excused by the contract, which stated that [REDACTED] would not be liable for damages payments if underperformance is caused by "any act of God, war, mobilization, flood, insect, disease, infestation, strike, lockout, storm, ice, fire, government restriction, government regulation, road closure, plant or mill downtime, markets, or woods closure, or any other cause beyond its reasonable control whether or not similar to those specifically enumerated above."³⁰⁶

Figure VI-14 shows the total amount of primary biomass fuel (chips) and secondary biomass fuel (bark) delivered to the biomass unit on NSPI's behalf.

³⁰⁵ [REDACTED] - 20231231 First Amending agreement," section 4.

³⁰⁶ [REDACTED] - 20231231 First Amending agreement," section 14.

Figure VI-14: NSPI's 2024, 2025 Primary and Secondary Biomass Fuel Deliveries (Metric Tonnes)

Month	Primary (MT)	Secondary (MT)
January-24		
February-24		
March-24		
April-24		
May-24		
June-24		
July-24		
August-24		
September-24		
October-24		
November-24		
December-24		
January-25		
February-25		
March-25		
April-25		
May-25		
June-25		
July-25		
August-25		
September-25		
October-25		
November-25		
December-25		

We sampled selected deliveries to confirm that prices charged (in the invoices) matched those in the contracts. We found no discrepancies.

VI.B.12.a. Contract Quality

The quality of biomass fuel is specified in each supplier contract, typically containing targets and limits on the size, lack of contamination (i.e., free of rock, plastic, etc.), and the type of wood (natural, untreated, uncoated). The primary quality metric is moisture content, and each contract contains both targets and limits for moisture content of fuel received.³⁰⁷ As explained above, [REDACTED] of NSPI's supply arrangements contain payment adjustments or damages clauses that would allow recovery of some cost of fuel deliveries that violate contractual limits. NSPI does have rights under each [REDACTED] agreement to reduce or reject shipments and otherwise suspend the agreement.³⁰⁸

³⁰⁷ See, for example, "[REDACTED] 2023 Biomass Supply Agreement," section 7.3.

³⁰⁸ See, for example, "[REDACTED] - 20230122 Biomass Purchase Sale Agreement," Appendix A.

Overall, moisture content for both bark and primary biomass were below contractual targets. NSPI identified limited instances during the Audit Period when biomass deliveries exceeded target moisture contents:

- January to April 2024 (bark): Moisture contents were above the target moisture content by an average of █ percent with a range of █ percent above in February to █ percent above in March. Bark moisture levels were consistent across suppliers, suggesting seasonality impacts on overall supply.
- January to April 2024 (primary biomass fuel): Sawmill chip moisture contents were above the target moisture content by an average of █ percent, with a range of █ percent below in April to █ percent above in February. NSPI explained that weather conditions affected delivery of sawmill chips from █ leading to a higher inventory on the ground that was exposed to precipitation.

For reasons explained above, NSPI did not take any contractual action or interventions with its biomass fuel suppliers in response to these limited instances of excess moisture content. NSPI also noted that the occasional increase in moisture content is expected because biomass fuel moisture content is seasonal.

VI.B.12.b. Bates White's Contract Samples

To test the contractual compliance of NSPI's solid fuel suppliers, we sampled 27 biomass deliveries across the Audit Period. We reviewed quality results for these deliveries. Specifically, we examined the moisture content results and compared them to contractual specifications. Of the 27 samples, three had moisture contents that were slightly above the moisture target (less than one percentage point higher, on average).

VI.B.13. Inventory Adjustments

As is shown in Figure VI-15, the biomass unit had several adjustments during the Audit Period. In the aftermath of the cyber event, when NSPI did not have access to Aligné Fuels, NSPI did not conduct any adjustments. NSPI wanted to avoid making any adjustments until it had access to Aligné to avoid the need for any retroactive changes. Once it regained access, NSPI applied a Q4 2025 inventory adjustment.

Figure VI-15: Port Hawkesbury Biomass Inventory Adjustments

Quarter	Blended Pile (MT)	Chips (MT)	Total
Q1 2024	829	(5,515)	(4,686)
Q2 2024	(9,640)	4,181	(5,459)
Q3 2024	(7,137)	2,223	(4,914)
Q4 2024	10,206	(691)	9,515
Q1 2025	109	10,011	10,120
Q2 2025	No survey adjustments (Cyber Attack)		
Q3 2025	No survey adjustments (Cyber Attack)		
Q4 2025	11,883	(4,883)	7,000

Regarding the final inventory adjustment, NSPI stated that the adjustments were pending as they had not yet been agreed to by PHP. NSPI noted that due to the codification of the energy balance process, “retroactive adjustments” were made to 2024 and 2025 results. We include a recommendation that NSPI update the Board with the results of this effort, including the consumption, cost, and inventory impact of the final adjustments.

In our prior audit report, we explained that tracking error is the primary cause of the need for inventory adjustments, particularly because NSPI’s fuel is commingled with PHP’s fuel in the boiler.³⁰⁹ We included a recommendation that NSPI “consider an investigation of its biomass inventory processes to determine ways to reduce the need for the quantity and magnitude of inventory adjustments in the future.”³¹⁰ In response, NSPI explained that it reviewed its inventory processes, including frequency of fuel pile surveys and segregation measures. NSPI also expanded the use of the portion of the PHB site where inventory is held to accommodate additional piles for stored bark and fuel logs. We observed evidence in the audit record of NSPI engaging with PHP to move inventory at times, including to PHP-owned portions of the site. Some of these activities were in response to Audit Period-specific events, such as the blended pile combustion issues (explained in section VI.A.8 above) and acceptance of fuel logs from █████ in excess of forecasted needs (explained in section VI.A.7 above). Our prior recommendation did not recommend that NSPI revise its processes, but rather “consider an investigation” of those processes. We consider NSPI to have been responsive to our recommendation.

VI.B.14. Bates White’s 2022-2023 Audit Recommendations

In our report for the prior audit period, we offered five recommendations related to biomass fuel. This section assesses NSPI’s actions related to those recommendations.

³⁰⁹ 2022-2023 Bates White Audit Report, page 152.

³¹⁰ 2022-2023 Bates White Audit Report, Recommendation VI-4.

Recommendation VI-1: NSPI should require its biomass supply RFP respondents to provide the key commercial terms of their offer in their written bid submission.

NSPI accepted the recommendation and indicated that “on a go forward basis [NSPI] will apply this requirement for respondents to provide the key commercial terms of their offer in written bid submissions.” We noted in our July 6, 2023 Rebuttal Evidence that we considered NSPI’s responses to be “positive and satisfactory.”³¹¹ In practice, NSPI did not fully adopt this recommendation. As we explain above, there was an instance where in response to the June 2024 biomass supply RFP, [REDACTED] offer contained “TBD in Contract” for both quantity of volume offered and average moisture content of the fuel being offered. However, in the July 2025 biomass supply RFP, [REDACTED] bid appropriately indicated the quantity and quality of the fuel being offered. The timing of our recommendation may have been received and implemented after the [REDACTED] offer was received and evaluated in the June 2024 RFP. As such, we consider NSPI to have addressed our recommendation, as evidenced in the July 2025 RFP.

Recommendation VI-2: To account for NSPI’s demonstrated preference for Fuel Log Chips over competitive alternative types of primary biomass fuel, NSPI should consider specifying targeted quantities of Fuel Log Chips in future biomass supply procurements.

NSPI initially accepted the recommendation, but provided no additional detail as to how it would implement the recommendation, which we pointed out in Rebuttal Evidence.³¹² NSPI indicated that beginning with the July 2025 biomass supply RFP, it specified fuel log chip quantities and that it would continue to include a range of specific biomass fuel quantities in future RFPs. We confirmed that NSPI implemented this improvement in the July 2025 RFP, where NSPI specified specific quantity range targets for secondary forecast biomass, chips from sawmill operations, primary forest chips, and biomass roundwood. This is a significant improvement to the RFP process and we consider our recommendation to have been fully addressed.

Recommendation VI-3: NSPI should complete its negotiations of amendments to the Shared Services Agreement with PHP, especially codifying the energy balance process.

NSPI accepted the recommendation and executed an associated revision to the Shared Services Agreement on March 7, 2025. We address that revision and the energy balance process above in section VI.A.8. We consider NSPI to have fully addressed this recommendation.

Recommendation VI-4: NSPI should consider an investigation of its biomass inventory processes to determine ways to reduce the need for the quantity and magnitude of inventory adjustments in the future.

NSPI accepted the recommendation and took actions we discuss above in section VI.A.13. We consider NSPI to have fully addressed this recommendation.

³¹¹ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 7 line 2.

³¹² Bates White Rebuttal Evidence, M11533, February 21, 2025, page 8 lines 1 to 3.

Recommendation VI-5: NSPI should finalize Revision 14 to the Fuel Manual.

NSPI accepted the recommendation and filed Revision 14 of the Fuel Manual on October 28, 2024. We consider this recommendation to be fully addressed.

VI.C. Conclusions

Conclusion VI-1: Biomass consumption in the Audit Period (█████ GMT) was █████ percent higher than in the prior Audit Period and the highest since at least 2018-2019, with 2025 consumption (█████ MT) materially higher than 2024 consumption (█████ MT). Accordingly, PHB produced 346.6 GWh, the highest over that period as well (and 22% higher than output in the prior audit period.)

Conclusion VI-2: NSPI increased the percentage of primary biomass fuel in the PHB blend during the Audit Period, reaching as high as █████% during the Audit Period, with tests as high as █████%. Natural gas made up approximately █████% of the unit's output in the Audit Period.

Conclusion VI-3: Higher biomass consumption during the Audit Period was primarily driven by the treatment of OBPS program, which often results in the unit being the lowest cost dispatchable resource. PHB generated \$█████/MWh in OBPS credits in 2024 and \$█████/MWh in 2025.

Conclusion VI-4: NSPI's codified processes for biomass fuel procurement as found in the Fuel Manual remain sound.

Conclusion VI-5: NSPI received biomass supply from a more robust number of suppliers (█████) during the Audit Period.

Conclusion VI-6: In the January 2024 biomass supply RFP, NSPI's decision-making was reasonable, and exhibited good practice by seeking FST approval of a revised offer from █████ (after already receiving FST approval to enter negotiations with █████ following the selection of █████ offer in the RFP). NSPI did purchase █████ GMT of fuel logs from █████ that it did not need, but did so due to the contingency of █████ bark volumes offer (which NSPI needed) on taking fuel logs as well. NSPI indicated that bark was otherwise too scarce to turn down █████ offer, and while NSPI provided some evidence of this (but not definitive proof), the large OBPS credits generated by the unit are so large (nearly \$█████/MWh in 2025) that there is substantial headroom to absorb higher biomass fuel costs before the PHB unit becomes uneconomic. On net, therefore, this additional fuel from █████ was beneficial for customers.

Conclusion VI-7: NSPI received █████ GMT of fuel logs from █████ in 2024 via deliveries made from February through November of 2024. However, we did not observe any instances of PHP providing chipping services for the fuel logs to make them ready for consumption in the PHB boiler until January of 2025. NSPI does not have any covered storage at the PHB site, meaning that these fuel logs were stored for months subject to the elements, which can harm their moisture content and quality and therefore the

efficiency of the PHB boiler. NSPI stated that the risk associated with long periods of storage was limited to logs on the outside of the pile (the portion exposed to the elements). NSPI also stated that the logs were held in reserve and chipped only when needed. We do not have an estimate of the impact of the extended storage of the fuel logs prior to chipping.

Conclusion VI-8: Given the low turnout to the June 2024 biomass supply RFP, NSPI could improve its RFP process by removing the stated preference for biomass supply contracts with terms that are not less than two years and specify the time period(s) of NSPI's biomass supply need. **(Recommendation VI-1) (Recommendation VI-2)**

Conclusion VI-9: NSPI's decisions in the wake of the June 2024 biomass supply RFP appear to reflect the realities of the biomass fuel landscape in Nova Scotia. Some suppliers were largely willing to provide secondary biomass fuel only if NSPI was willing to accept material volumes of primary fuel. This led to surplus purchases, particularly for primary biomass fuel, which imposed incremental costs on FAM customers. For example, NSPI's purchases in the fourth quarter of 2024 led to a surplus of █████ GMTs of primary fuel and █████ GMTs of secondary fuel, for a combined cost of \$█████. At the same time, the PHB unit's value has materially appreciated under the OBPS regime, which allows PHB to generate large OBPS credits that reduce costs for FAM customers. During the Audit Period, PHB generated \$████ million in OBPS credits. PHB also contributes to NSPI's other environmental compliance efforts, including emissions and renewable energy standards. The surplus fuel itself can also still be consumed at the PHB boiler, and consumption in 2025 was the highest in several years. NSPI has also taken steps to adapt to the challenges in procuring bark, including higher primary fuel blends in PHB's fuel mix.

Conclusion VI-10: Some of NSPI's executed contracts lacked execution dates. **(Recommendation VI-3)**

Conclusion VI-11: In 2024, NSPI incurred FAM costs of \$█████ for services from PHP related to biomass inventory pile combustion. PHP provides operations and maintenance services to NSPI at PHB, which includes responding "in a commercially reasonable manner to hot spots and open fires in the storage piles" and that "Biomass Fuel that is hot, smoldering or on fire shall be separated from the Biomass Fuel storage piles or otherwise handled in a prudent manner." NSPI, meanwhile is required to "cooperate with PHP to use or remove hot Biomass Fuel expeditiously upon request." NSPI indicated during the audit that during this event, the scope of required services expanded beyond a routine and commercially reasonable response to isolated hot spots to a concerted effort to address large developing hot zones in order to prevent imminent fire and potential major damage to the bark pile. The contract language does not explicitly indicate NSPI will be responsible for incremental costs, only that NSPI will cooperate in either consuming that fuel or removing it. Moreover, cooperation from NSPI is necessary since it is NSPI's fuel—if PHP was to remove that fuel unilaterally, it would be an act of destruction or theft. Should the Board consider a disallowance for these costs, we agree with NSPI that the cost of the event is \$█████ with no demonstrable loss of inventory.

Conclusion VI-12: NSPI appropriately codified the energy balance process into the Shared Services Agreement. The energy balance process has been revised and includes a complex Energy Balance Worksheet that is not part of the Shared Services Agreement.

Conclusion VI-13: NSPI has appears to have applied the energy balance process consistent with the Shared Services Agreement as revised.

Conclusion VI-14: We have four concerns with the energy balance process. First, the “Step 1” moisture target, which is set at a fixed █%, is rigid, and that rigidity could lead to outcomes that unduly favor (or disfavor) PHP, relative to FAM customers. Second, the “Step 2” moisture target is subject to a “collar” (floor and ceiling values) that should be reconsidered. Third, the energy balance process allows PHP to carry “negative” balances on its ledger with NSPI indefinitely and penalty-free. Fourth, the price of chips applied to PHP chip deficits under the energy balance process when PHP’s chip deficit exceeds the chip volumes delivered by PHP (such that NSPI burns chips from other suppliers to serve PHP’s industrial demand) should be clarified to reflect the actual cost of the chips consumed on PHP’s behalf.

(Recommendation VI-4) (Recommendation VI-5) (Recommendation VI-6) (Recommendation VI-7)

Conclusion VI-15: NSPI’s processes and procedures for receipt and quality control of biomass fuel are reasonably explained in the Fuel Manual.

Conclusion VI-16: For the Audit Period, █ were NSPI’s largest biomass fuel suppliers. █ provided █% of all biomass fuel in 2024 and █% in 2025. █ provided █% in 2024 and █% in 2026.

Conclusion VI-17: In 2024, NSPI received NSPI received █ GMT in excess of contractual minimums for primary biomass fuel, or + █%, while receiving █ GMT less secondary biomass fuel than contracted, an underage of █%. In 2025, suppliers delivered less primary biomass fuel (█%) and secondary biomass fuel (█%) than contracted. In the one case of a contractual ability to pursue liquidated damages, the under-deliveries by the seller (█) in 2024 and 2025 were found to be excused by the supply agreements terms.

Conclusion VI-18: In 2025, there were multiple factors that impacted biomass supply and deliveries. First, summer wildfires and fire risk conditions triggered restrictive provincial regulatory and legal steps, such as “woods bans,” which according to NSPI’s consultant █ led to “widespread operating restrictions and diversion of significant harvesting capacity toward fire-suppression results.” Second, new tariffs announced in 2025 by the U.S., a key export market for provincial lumber, harmed demand and sawmill economics along with it, leading to increased downtime and less output. Third, on March 1, 2025, a heavy equipment vehicle working at the PHB site struck the radial stacker conveyor structure that conveys delivered secondary biomass fuel from trucks to PHB’s inventory piles, limiting the plant’s ability to accept bark deliveries from self-unloading tractor-trailer trucks only, a limitation that was in place until September 24, 2025. Self-unloading trucks are not standard or otherwise required by NSPI for its suppliers, and NSPI confirmed that suppliers that were unable to secure access to self-unloading trucks

were unable to deliver bark to PHB. [REDACTED] was most impacted and indicated to NSPI that because of this issue, it could not deliver its bark and instead sold [REDACTED] GMT to other customers.

Conclusion VI-19: NSPI's biomass suppliers provided fuel that was reasonably in line with targeted moisture content. NSPI does not have the contractual ability to pursue damages, but does retain the right to reduce, reject, or suspend shipments that do not meet specifications.

Conclusion VI-20: In the aftermath of the cyber event, when NSPI did not have access to Aligné Fuels, NSPI did not conduct any biomass inventory adjustments in order to avoid making any adjustments until it had access to Aligné to avoid the need for any retroactive changes. Once it regained access, NSPI applied a Q4 2025 inventory adjustment. NSPI stated that the Q4 2025 adjustments were pending as they had not yet been agreed to by PHP, noting that due to the codification of the energy balance process, "retroactive adjustments" were made to 2024 and 2025 results. **(Recommendation VI-8)**

Conclusion VI-21: NSPI has adequately addressed our biomass fuel-related recommendations from the prior audit report.

VI.D. Recommendations

Recommendation VI-1: NSPI should consider revising future biomass supply RFPs to reduce or remove preference for supply contracts of 2-years or greater, given the inability or unwillingness of suppliers to offer such terms and the potential negative impact this preference may have on participation.

Recommendation VI-2: Future biomass supply RFPs should specify the time period(s) of its biomass supply need for which it is inviting offers.

Recommendation VI-3: NSPI should ensure that its FAM-related contracts include execution dates from their signatories.

Recommendation VI-4: NSPI should consider ways to revise "Step 1" of the energy balance process in specifying a target moisture content that accounts for the dynamism in PHB's relative economics and the biomass fuel supply realities in the province to prevent instances of unduly high or low payments by PHP.

Recommendation VI-5: NSPI should consider relaxing or removing the moisture target "collar" in "Step 2" of the energy balance process.

Recommendation VI-6: NSPI should consider an enhancement to capture the time value of PHP bark deficits determined under the energy balance process that carry over into future months.

Recommendation VI-7: NSPI should consider ways to clarify the price of chips applied to PHP chip deficits under the energy balance process when PHP's chip deficit exceeds the chip volumes delivered by PHP (such that NSPI burns chips from other suppliers to serve PHP's industrial demand) to better reflect the actual cost of the chips consumed on PHP's behalf.

Recommendation VI-8: NSPI should update the Board with the results of its effort to reconcile biomass inventory adjustments and energy balance results in Q4 2025 that carried over to 2026.

VII. Natural Gas Supply Planning

VII.A. Background

NSPI's gas-fired facilities are served by the Maritimes & Northeast Pipeline – Canada ("M&NE-CA"). During the Audit Period, gas transported on this pipeline was sourced from the U.S. and Canada via the TransCanada Pipeline ("TCPL"), Portland Natural Gas Transmission System ("PNGTS"), and the U.S. portion of the Maritimes & Northeast Pipeline ("M&NE-US"), some limited, winter-only gas production from Headwater Exploration Inc., and from other countries as liquefied natural gas ("LNG") through the St. John LNG terminal in St. John, NB.³¹³ As part of its planning activities to obtain natural gas delivered to Tufts Cove during the Audit Period, NSPI necessarily evaluated and contracted for pipeline capacity or delivered gas purchases to effect receipt of the natural gas. It had an opportunity to obtain additional pipeline capacity but declined due to concerns about the cost and the possibility of reduced need for gas in the longer term. It also participated in pipeline regulatory proceedings with other shippers to negotiate revisions to terms of service.

VII.B. Findings

NSPI evaluated various firm and interruptible pipeline transportation options and made decisions on whether to contract for pipeline capacity based on short-term analyses that corresponded to the terms of the contracts. It also evaluated and declined a 10-year offer of firm transportation (FT) from Dawn to Westbrook using long-term, IRP-related modelling, but did not adequately consider potential economic offsets or alternate scenarios. As we explain below, this had no effect on FAM costs during the Audit Period, though it may have an effect on FAM costs in the future. NSPI properly evaluated and supported its decision to renew and expand a transportation contract on M&NE-CA. NSPI also participated in pipeline regulatory proceedings regarding rates. We provide more details of our findings below.

VII.B.1. Introductory Context for NSPI's Natural Gas Supply Options

Entering the Audit Period, NSPI was able to source gas from the south via the Maritimes & Northeast Pipeline (M&NP) system, which also gave it access to re-gasified LNG from the St. John LNG facility in New Brunswick.³¹⁴ Some gas was available from New England via the Algonquin system, but the majority of gas supplies were brought onto the M&NP system via TCPL/PNGTS and Repsol.³¹⁵ During

³¹³ As discussed in NSPI's annual Natural Gas Reports, there are typically small amounts of gas produced by Headwater Exploration Inc. during winter periods. See, for example, NS Power 2025 Natural Gas Report, page 7.

³¹⁴ NS Power 2025 Natural Gas Report, page 60. This facility was formerly known as Canaport.

³¹⁵ NS Power 2025 Natural Gas Report, section 2.5.

the Audit Period, NSPEMI (an NSPI subsidiary) conducted natural gas and electric transactions in the United States for export to Canada on behalf of NSPI. In 2021, NSPI had contracted for 20,000 MMBtu of firm pipeline capacity from Empress, AB to Westbrook, ME. This capacity consisted of three firm transportation contracts, two on TCPL and one on PNGTS. [REDACTED]

[REDACTED]

[REDACTED]

VII.B.2. Audit Period Gas Transportation Options Considered by NSPI

Natural gas is a commodity, and if pipeline access to gas is available, then contracting for the gas commodity is straightforward. It is more complex to contract for FT capacity to transport gas from the point of purchase to the point of delivery. However, existing FT contract holders may, from time-to-time, release these firm rights to other shippers for negotiated prices and periods of time. During the Audit Period, NSPI considered and accepted assignment of FT capacity in the US and the use of existing and renewed interruptible transportation (“IT”). There were no rate proceedings on the M&NE-US system during the Audit Period. NSPI also extended its [REDACTED] MMBtu per day FT contract on M&NE-CA through 2026. In Canada, the rates for IT transportation are higher than the FT rates. Therefore, anytime that NSPI could take assignment or contract for FT capacity on M&NE-CA, the cost of transporting gas from Baileyville would be lower. In the U.S., when IT capacity was available, it was often priced (but not always) at a discount to the FT rate. NSPEMI was able to contract for released M&NE-US capacity from time to time at a discount to the firm rate.

VII.B.2.a. Capacity Assignment on Maritimes & Northeast Pipeline System

During portions of the Audit Period, NSPI/NSPEMI accepted the assignment of pipeline capacity on the M&NE system. For one week in January and all of February 2024, and again for November 2024 through March 2025, NSPEMI accepted over [REDACTED] MMBtu per day of FT capacity on M&NE-US from [REDACTED]. For April 2024 through October 2024, NSPEMI also accepted up to [REDACTED] MMBtu per day of FT capacity on M&NE-US from [REDACTED]. The Jan-Feb release from [REDACTED] was accepted to reduce potential risk posed by a scheduling process change on M&NP US’s pipeline nomination system. The latter releases were pursued as a longer-term solution to the aforementioned process change and came at the rates of US \$ [REDACTED]/MMBtu (Apr-Oct 2024) and \$ [REDACTED]/MMBtu (Nov 2024-Mar 2025), respectively (both of which were at a discount to the IT rate).

NSPEMI accepted three discounted releases for FT capacity on M&NE-US from [REDACTED] for April 2025, May 2025 through October 2025, and November 2025 through March 2026, respectively. The volumes of the April 2025 and May-October 2025 releases were [REDACTED] MMBtu/day at the rate of US \$ [REDACTED]/MMBtu. The volume of the November 2025 through March 2026 release was [REDACTED] MMBtu/day at the same rate of US \$ [REDACTED]/MMBtu. Each of these capacity releases came at a discount of approximately US \$ [REDACTED]/MMBtu compared to the posted toll of US \$ [REDACTED] for MNIT transport.

VII.B.2.b. Interruptible Capacity on M&NE-US

When NSPEMI began energy transactions in the US in November 2020, they were able to buy gas at Westbrook, ME and transport it to Baileyville, ME using IT capacity on M&NE-US. This continued throughout the Audit Period.

VII.B.2.c. Firm Transportation from Alberta

NSPEMI continued to manage the FT contracts on TCPL and PNGTS used to transport [REDACTED] MMBtu per day from Empress, AB to Westbrook, ME. They then arranged for the re-delivery of this gas to NSPI at Baileyville.

VII.B.2.d. Minimum Revenue IT Service

At the conclusion of the prior audit period, NSPI renewed the MNITMR contract for 2024 through 2025 at a minimum revenue requirement of CAD \$ [REDACTED] million over the two-year term.³¹⁶ The rates remained at 150 percent of the 100 percent load factor firm rates during the winter (November – March), and 100 percent of the 100 percent load factor firm rates during the summer (April – October). In the current Audit Period, ERM evaluated the economic attributes of different service types (and different configurations of these types) available for contracting when shipping natural gas on the M&NE-CA pipeline, including FT, MNITMR, IT, FT with MNITMR, and FT with IT. This evaluation found that the lowest cost to customers while maintaining dispatch flexibility was to contract for [REDACTED] MMBtu/day of FT transport in 2026 and defer a decision on contracting for 2027 transport until the latter half of 2026. As such, ERM recommended not renewing the MNITMR contract for the 2026-2027 period.

VII.B.2.e. The MN365 FT Contract

With the advent of the [REDACTED] MMBtu per day firm gas supply from Alberta, NSPI sought to match it with an MN365 FT contract on M&NE-CA because there was little doubt that this gas would be used by NSPI every day. This contract, which went into effect on January 1, 2022, was for an initial term of two years and gave NSPI the flexibility to sell and deliver unneeded gas in the NB/NS market, including Baileyville.³¹⁷ NSPI subsequently renewed this contract for the 2024-2025 period at a level of [REDACTED] MMBtu per day. As mentioned earlier, in the current Audit Period, NSPI elected to contract for [REDACTED] MMBtu/day of FT transport on M&NE-CA in 2026 and defer a decision on contracting for 2027 transport until the latter half of 2026. The analysis accompanying the decision was thorough and supported the decision. Of note, the NSPI analysis considered trade-offs between contracting levels and the effect on both FT rates and MNITMR commitment levels. NSPI also participated with other shippers in the negotiations with M&NP-CA to lower the MN365 rates.

³¹⁶ 2022-2023 Bates White FAM Audit Report, p. 162.

³¹⁷ 2020-2021 Bates White Audit Report, Section VI.B.2.e.

VII.B.2.f. The [REDACTED] FT Offer

In late 2024, [REDACTED] offered up to [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED] The capacity was offered for terms of 20 or 10 years, with the demand charge for the former set equal to [REDACTED] % of the maximum rate from Empress to East Hereford, and the demand charge for the latter set equal to the maximum rate from Empress to East Hereford. NSPI chose not to pursue [REDACTED] capacity from [REDACTED]. Though the structure of NSPI's analysis and presentation of findings was consistent with what would otherwise be included in a formal ROA, due to an oversight, this information was ultimately not included in one. That said, references to the offer and associated analysis are present in other documents (e.g. NS Power's 2025 Natural Gas Report).³¹⁸

Assuming [REDACTED] MMBtu/day was elected, NSPI used the results of an existing modeling run to identify how much of this additional [REDACTED] capacity would be used on a daily basis during three separate years (2030, 2035, and 2040) and calculated the cost of the gas used under the forecast prices [REDACTED]. Over the three years, the savings resulting from the cheaper [REDACTED] gas compared to higher cost of spot gas were more than offset by the fixed demand charges.

This analysis assumed that there would [REDACTED]
[REDACTED]
[REDACTED]). Further, it was assumed that the existing long-term FT contracts from Empress to Westbrook would be extended through 2040 rather than being allowed to expire on October 31, 2036.

The results of NSPI's analysis showed a decline in the use of both the existing FT and the incremental capacity, over time. The utilization rate for the incremental capacity averaged [REDACTED] % over the three, one-year periods. As a result, the savings in 2030 were more than offset by losses on a cumulative basis over the three years examined. Assuming an increase in commodity prices of [REDACTED] % led to a cumulative loss of approximately \$[REDACTED] million, while an increase of [REDACTED] % in commodity prices led to cumulative savings of more than \$[REDACTED] million. Modelling of the longer term, lower toll offering also showed cumulative losses over the sample years, but to a lesser extent.

NSPI concluded that this FT capacity would be uneconomic and did not bid on the capacity. The reasons listed supporting their conclusion follow:

- Given the increased volatility in the daily gas demand forecasted firm capacity is not an inherently good fit for securing gas supply in the future state.

³¹⁸ NS Power 2025 Natural Gas Report, page 61.

- The close to binary utilization of the capacity (e.g. not used at all, or completely used, on a given day) implies that it is not solving a gas supply problem. There are significant volumes of gas that still need to be procured on given days, and the solution to doing so could negate the need for the pipeline capacity.
- Long-term commitments to additional pipeline capacity could risk resulting in stranded capacity and increased costs to customers. Remarketing of the unused capacity has the potential to bring additional value, however that is a speculative assumption and is better categorized as an additional opportunity, rather than a core justification, for committing to pipeline capacity.
- Securing physical pipeline capacity with costs associated with a different pipeline path introduces the risk that changes in tolls impacts the costs associated with the physical commodity that adversely impacts the delivered cost (e.g. an increase in tolls on TCPL from Empress to East Hereford could reduce the price of physical gas at Empress all things being equal, however NS Power would not be able to avail itself of that lower cost gas because it's physical pipeline path is to Union-Parkway).

Bates White reviewed this analysis as well as the underlying models and data used. As we will explain in the following paragraphs, we do not share NSPI's conclusions, nor do we necessarily agree with its ultimate decision to reject the offer. It is worth noting at the outset that the modelling conducted by NSPI included the additional fast-acting, gas-fired combustion turbines planned for the Pictou area. NSPI has since confirmed that it will not be responsible for supplying gas to these gas-fired combustion turbines.

First, some assumptions did not reflect the normal course of business in wholesale, natural gas operations. For example, assuming there was no market value in unused capacity does not reflect reality. If the contracting decision is dependent on the price forecasts, then the decision not to recognize the value of the price spread in evaluating the contract means that NSPI intentionally would not take steps to monetize the spread value. The spread between the variable cost of gas sourced at [REDACTED] and the spot gas price can be significant during certain times of the year. Using NSPI's data, this difference ranged from a maximum of \$[REDACTED]/MMBtu to a minimum of \$[REDACTED]/MMBtu, with an average difference of \$[REDACTED]/MMBtu. To assume that gas could not be sold into a market with a positive gross margin does not make economic sense. NSPI does not dispute that there is a potential for reselling gas or releasing capacity but notes these are not guaranteed and introduce additional risk. Further, concluding FT "is not an inherently good fit" for a more variable gas load profile ignores a consideration of whether it makes economic sense. This perspective is emerging as a position taken by ERM but not reflective of official NSPI policy. We discuss this further in Section VII.B.2.h below.

Second, the structure of the analysis appears to be skewed by utilizing three snapshot years rather than the entire offer term. Selecting only three years and excluding the costs/savings from the earlier,

intervening years, masks the effect the results from the intervening years might have had on the cumulative costs/savings. As NSPI agrees, the appropriate way to evaluate a long-term FT contract is on an NPV basis. If the earlier years showed benefits, then these would factor more heavily in an NPV analysis than losses in later years. Unfortunately, by not including all years in the analysis, the NPV of the FT contract could not be calculated.

Third, extending the existing long-term FT contracts beyond their expiration date biased the analysis. Regardless of the renewal terms of the existing capacity, if the analysis had allowed the existing FT contracts to expire, then the utilization rate of the incremental FT contract would have been higher, possibly generating savings for the FAM customers in the later years. This would also affect the NPV of the incremental FT contract.

Last, Bates White considers concern related to fixed demand charges—specifically, paying fixed demand charges at one receipt location when the actual FT receipt point is at a different location—to be a distraction. Once the FT contract is executed, the demand charges become fixed costs, essentially the cost of a physical option to purchase gas at Dawn. Should the gas commodity prices at Empress change because of a change in pipeline demand charges, NSPI would still be buying gas at Dawn. In short, paying a negotiated demand charge for FT capacity with a receipt point at Dawn can be evaluated on a stand-alone basis. If a buyer does not have access to a market in Empress, then price changes in that market are irrelevant.

To understand the effect of these assumptions on the NSPI analytical results, Bates White modified the model developed by NSPI to allow unused FT capacity to be used to sell gas into spot markets. Bates White calculated the cumulative costs/savings under three scenarios – selling unneeded gas at [REDACTED] of the market price. In reality, gas would likely be sold at a discount to the market price since it would require additional transportation costs to reach other markets.³¹⁹ The following table illustrates the effect on the cumulative costs/savings under the three scenarios. Clearly, excluding the economic benefits of actively managing an FT contract from the analysis provided an incomplete picture, particularly since NSPEMI now has the capability of selling into MA and NH. Keep in mind that these results are associated with the three snapshot years, the existing [REDACTED] MMBtu contract being extended, and no remarketing of the unneeded capacity from these existing FT contracts.

Figure VII-1: Cost Savings Associated with Sale of Unneeded Gas ([REDACTED] Offer)

Sale Price as a Percentage of Market Price	Savings
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]

³¹⁹ The FT contract evaluated by NSPI had a firm delivery point at Dracut, MA, the interconnection with Tennessee Gas Pipeline. Deliveries to a market at Dracut could be accomplished through a nomination change at no additional cost.

Further clouding NSPI's analysis of the [REDACTED] offer is the fact that it did not conduct a formal ROA of the offer; the results of this analysis were discussed only within ERM. The existence of this offer was mentioned in [REDACTED] response to a gas supply RFP issued by NSPI and provided to Bates White in response to a data request.

VII.B.2.g. The TCPL and PNGTS Open Seasons

In July and August of 2025, TCPL and PNGTS issued coordinating Open Seasons for new FT capacity on their respective systems.³²⁰ The TCPL open season invited prospective shippers to bid on up to [REDACTED] MMBtu/day of FT capacity from Empress, AB to East Hereford, QC (the interconnection with PNGTS). Bids could vary the quantity (MMBtu/day), rate, and contract term, with a minimum of 15 years. The new FT service was expected to be available by November 1, 2028.³²¹ The PNGTS open season invited prospective shippers to bid on FT capacity from East Hereford to either Westbrook or Dracut, MA (the PNGTS interconnection with Tennessee Gas Pipeline).³²²

NSPI, in anticipation of these coordinated open seasons, modelled the economics of this potential transportation opportunity using Plexos. Underlying these analyses were some key assumptions. NSPI used the most recent available system assumptions established in the system planning NB Reliability Tie model to estimate new generation capacity and composition over the period from 2028 to 2043 (including fast acting gas turbine capacity, coal phase-outs, and new renewable assets). NSPI also modelled natural gas prices with price escalators of [REDACTED] respectively, and with additional capacity utilization of approximately [REDACTED] over the study period (consistent with previous open season modelling). The value of releasing capacity or selling gas into other markets was not included in the analysis.

In the memorandum in ROA PL0025 supporting the decision not to bid for FT capacity, NSPI reached the following conclusions:

While commodity costs decrease with the access to the open season capacity which provides access to economically priced AECO gas, after the inclusion of the incremental FT pipeline costs, total costs increase by approximately \$ [REDACTED] million annually as compared to the status quo. This is assuming current TCPL tolls and no escalation as a best-case scenario...

³²⁰ At the time of previous open seasons, TC Energy owned 61.7% of PNGTS and 100% of TCPL. TC Energy divested from PNGTS in 2024 as part of a sale to BlackRock and Morgan Stanley Infrastructure Partners.

³²¹ TCPL, "TCPL's Firm Transportation New Capacity Open Season," July 2025, <https://www.tccustomerexpress.com/assets/2025%20NCOS%20Posting.pdf>.

³²² PNGTS, "Binding Open Season," July 2025, https://web-prd.myquorumcloud.com/PNGPA1IPWS/IPWSFile/IPWSFileHandler?path=%5CTSP_17%5C&fileName=Downloads%2FPNGTS%20Binding%20Open%20Season.pdf.

Given the increase in costs associated with additional, firm pipeline capacity, it is not recommended to make a bid in this open season. Future open seasons will continue to be evaluated with the latest available assumptions.

The modelling results indicated that pipeline capacity usage would decrease to an amount slightly above existing TCPL capacity until 2037, and would dip below existing capacity after 2037 and through the end of the study period. Further, NSPI expressed concern pertaining to, among other potential issues, the impact of future generation fleet composition changes, incremental cost risk from abandonment charges, and the probable length of capacity commitment based on successful bids in previous open seasons (25-30 years). As a result, NSPI decided to not submit a bid in either open season for the above reasons, noting additional open seasons would be available in the future.

VII.B.2.h. NSPI's Position Regarding FT Pipeline Capacity

In response to a data request, NSPI described their perspective on when it was appropriate to contract for FT pipeline capacity. To summarize, NSPI's view is that any new FT capacity "should be justified on an economic basis via reducing the cost of actual natural gas delivered to NS Power's facilities. Potential remarketing benefits associated with unused capacity could be used to further support a commitment to long term capacity if the capacity showed economic benefit without it." Further, assuming FT capacity could be released, or gas remarketed, would be speculative, and "should not be part of the primary consideration for the commitment [to FT]." As noted earlier, this is not a formal NSPI policy, but rather an ERM position that may evolve. Bates White offers its perspective on this position noting that the uncertain role of the new NS IESO in procuring gas for any new, gas-fired generation makes NSPI's role less certain.

Bates White does not agree with ERM's position for a number of reasons. First, unlike the other fuels procured and managed by NSPI, natural gas procurement is a dynamic, just-in-time process. And, unlike other fuels that are stockpiled, natural gas purchase levels need to be adjusted continuously to best match generation requirements. This is done by buying and selling gas at the margin to stay within operating tolerances, which is done whether or not the associated transportation contracts are FT or IT. Accordingly, selling unneeded gas or releasing FT capacity is not speculative; instead, it is a core part of managing a natural gas portfolio, and should be reflected in any economic analysis of delivered spot gas versus FT and gas purchased at the receipt point. And, as we note in Chapter 8, NSPI was active in selling unneeded gas at a number of locations. An asset manager could also be used to manage an FT contract and deliver gas to NSPI when needed and would likely pay for the right to do so. This is a common practice in natural gas operations. As of April 29, 2026, there were five gas marketers listed as asset managers on the PNGTS website, managing seven FT contracts for a total of 113,691 MMBtu/day.³²³

³²³ PNGTS, "Index of Customers," accessed April 29, 2026, <https://web-prd.myquorumcloud.com/PNGPA1IPWS/IndexOfCust?tspno=17>

Second, to the extent that FAM customers would have access to lower cost gas in the short-term, but could face higher cost gas in the long-term, raises a challenge for NSPI to identify ways of accessing that lower cost gas while minimizing the long-term costs. We note that because NSPI would have to obtain Board approval prior to entering into a long-term FT contract, FAM customers hold the risk that the costs might eventually be higher. Further, FAM customers end up paying to mitigate that risk by paying for more expensive spot gas in the short-term. It should be noted that NSPI has the capability to hedge natural gas prices with HFO through fuel switching at Tufts Cove units 1-3, which occurred during the audit period to the benefit of FAM customers. This caps the fuel cost at the price of HFO, but this is not necessarily the same as hedging a gas price at Dawn. It is important to re-iterate that the FAM customers appear to hold the cost risk associated with an FT contract, not NSPI. Accordingly, the FAM customers should have a say in how much risk they are willing to take on. NSPI does not appear to hold the financial risk of underutilized FT contracts. The only risk that would be faced by NSPI in this hypothetical situation would be the consequence of not proactively managing FT capacity to minimize costs.

Third, NSPI's focus on projected contract utilization does not necessarily support the rejection of an FT contract unless lower utilization leads to costs higher than the next available alternative. The fixed cost of an FT contract allows access to lower cost gas. In short, it is the cost of a physical option to buy potentially lower cost gas. As an extreme example, consider the St. John LNG plant owned and operated by Repsol. Repsol holds an FT contract on M&NE-US for 730,000 MMBtu/day at an annual cost of \$103,249,740.³²⁴ This contract is used primarily during the winter months to deliver gas into markets when prices spike.³²⁵ Otherwise, the capacity is either released or not used. This is economic if, over time, the gross margin earned on gas sales and FT capacity releases exceeds the FT demand charges.

VII.B.2.i. Other IT Contracts

IT contracts with pipelines do not create any firm obligations for NSPI. There are no fixed costs under IT tariffs; there are only variable costs, which can change from time to time. This transportation is available to NSPI subject to the availability of pipeline capacity. Accordingly, IT contracts were not reviewed.

VII.B.3. Bates White's 2022-2023 Recommendations

In our report for the prior Audit Period, we included three recommendations regarding natural gas supply planning. The first recommendation read:

Recommendation VII-1: On an annual basis, NSPI should formally quantify what mix of short-term and long-term FT pipeline contracts and delivered gas supplies would result in the lowest overall cost to FAM customers. This quantification should include a quantification of risk

³²⁴ The asset manager for this contract is listed on the M&NE-US website as Emera Energy Services.

³²⁵ In January 2026, spot prices at the Algonquin city gate topped \$120/MMBtu. Assuming an LNG cost of \$10/MMBtu and gas sales of 730,000 MMBtu/day, Repsol could have made a gross margin of almost \$161 million on a weekend.

mitigation strategies including, but not limited to, reselling gas, releasing capacity, and various rate levels and contract terms. Further, NSPI has the opportunity to structure a request for FT capacity to one or more pipelines, if a need is identified.

NSPI accepted this recommendation and stated that “[f]or 2025, natural gas supply/pipeline contracting quantification of the mentioned characteristics will be included within the recommendations.”³²⁶ We noted in our February 21, 2025 Rebuttal Evidence that “while this is a positive response, NSPI should clarify the term of the pipeline capacity and supply analysis that will be performed annually (e.g., five years, ten years, etc.).”³²⁷ As we explain in section VII.B.2.h above, NSPI’s perspective on when it was appropriate to contract for FT capacity during the Audit Period, and specifically the view that “assuming FT capacity could be released or gas remarketed would be speculative,” necessarily disallows a complete quantification of the characteristics described in the recommendation. We therefore consider this recommendation unaddressed, and we reiterate our prior audit recommendation.

Our second recommendation stated:

Recommendation VII-2: NSPI’s participation with other shippers in the negotiation of tariff terms and conditions on upstream pipelines should continue, where and when needed, in CER and FERC regulatory proceedings.

NSPI accepted this recommendation and noted it would both “continue to work with other shippers to re-negotiate tariffs and reduce costs for customers” and “engage in the regulatory process pertinent to pipelines utilized by the Company where and when needed.”³²⁸ Bates White considered NSPI’s response to be “positive and satisfactory.”³²⁹ As described earlier, NSPI participated in the negotiations regarding new MN365 rates on M&NE-CA during the Audit Period.

Our third recommendation stated:

Recommendation VII-3: In conjunction with Recommendation VII-2, NSPI should periodically review the forecasted prices and assumptions used in its evaluations of FT and gas supply contracting activities for reasonableness and internal consistencies, and to ensure they reflect NSPI’s real world, business expectations. [Note: This Recommendation should have referred to VII-1, not VII-2.]

NSPI accepted this recommendation and stated that “[e]valuations for gas supply and pipeline contracted will utilize the most up-to-date assumptions available and applicable to the analysis.”³³⁰ We noted in our February 21, 2025 Rebuttal Evidence that “this is a positive response, but NSPI should

³²⁶ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.9.1.

³²⁷ Bates White’s February 21, 2025 Rebuttal Evidence, page 9 lines 1-3.

³²⁸ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³²⁹ Bates White’s February 21, 2025 Rebuttal Evidence, page 6 lines 19-20, page 7 line 5.

³³⁰ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.11.1.

confirm that it will periodically *review* the forecasts and assumptions, as stated in the recommendation.”³³¹ In its February 2026 update, NSPI confirmed that it “currently reviews assumptions used for the forecasting process, as well as the resulting forecast output on a periodic basis.” Bates White considers NSPI to have fully addressed this recommendation.

VII.C. Conclusions

Conclusion VII-1: NSPI does not appear to have completed the analyses made in Recommendation VII-1 from the previous FAM audit, which recommended that “[t]his quantification should include a quantification of risk mitigation strategies including, but not limited to, reselling gas, releasing capacity, and various rate levels and contract terms.” (**Recommendation VII-1**)

Conclusion VII-2: NSPI evaluated FT contract opportunities and explicitly excluded any quantification of risk mitigation strategies, resulting in the opportunities not being pursued to the possible detriment of FAM customers. (**Recommendation VII-1**)

Conclusion VII-3: NSPI appropriately entered into short-term FT contracts that provided access to natural gas at a lower cost and were operated at a high utilization rate and appropriately analyzed and terminated the MNITMR contract.

Conclusion VII-4: NSPI appropriately worked with other shippers on M&NE-CA to re-negotiate tariffs and reduce costs for its customers through 2027.

Conclusion VII-5: Continuing from the last FAM audit, NSPI continues to expect a decreasing reliance on natural gas due to changes in environmental constraints and a changing generation portfolio in the future.

Conclusion VII-6: NSPI appropriately planned to enter into an FT contract on M&NE-CA, effective January 1, 2022, for a term of two years, and renewed that contract for an additional two years.

Conclusion VII-7: NSPI’s ERM group has an evolving philosophy, which appears to have not been widely shared, regarding when it is appropriate to enter into longer term FT contracts.

VII.D. Recommendations

Recommendation VII-1: NSPI should conduct the analysis described in Recommendation VII-1, that was accepted by NSPI, from the 2022 – 2023 FAM Audit.

³³¹ Bates White’s February 21, 2025, Rebuttal Evidence, page 9 lines 9-10.

Recommendation VII-2: NSPI should re-do its analysis of the Freepoint FT capacity offer reflecting the following: use of the same assumptions and price forecasts for the 10-year term starting November 1, 2029, explicitly including the value of cost mitigation strategies (e.g., sales of unneeded gas, AMA, etc.) using unneeded existing FT capacity and Freepoint FT capacity, allowing the existing FT capacity to expire at term, and calculating the NPV of the net costs from November 2029 through October 2039 using the discount rate of the FAM customers.

Recommendation VII-3: NSPI should formalize a written draft of the ERM position on FT capacity, as described in VII.B.2.h. and in NSPI's response to DR 6-9, and provide it for review by the Board and FAM stakeholders. In generating that document, NSPI should clearly identify who (FAM customers, NSPI, or others) bears the risk of over-paying for unneeded longer-term FT capacity and why, and who currently pays to mitigate that risk by paying for spot gas.

VIII. Natural Gas Procurement

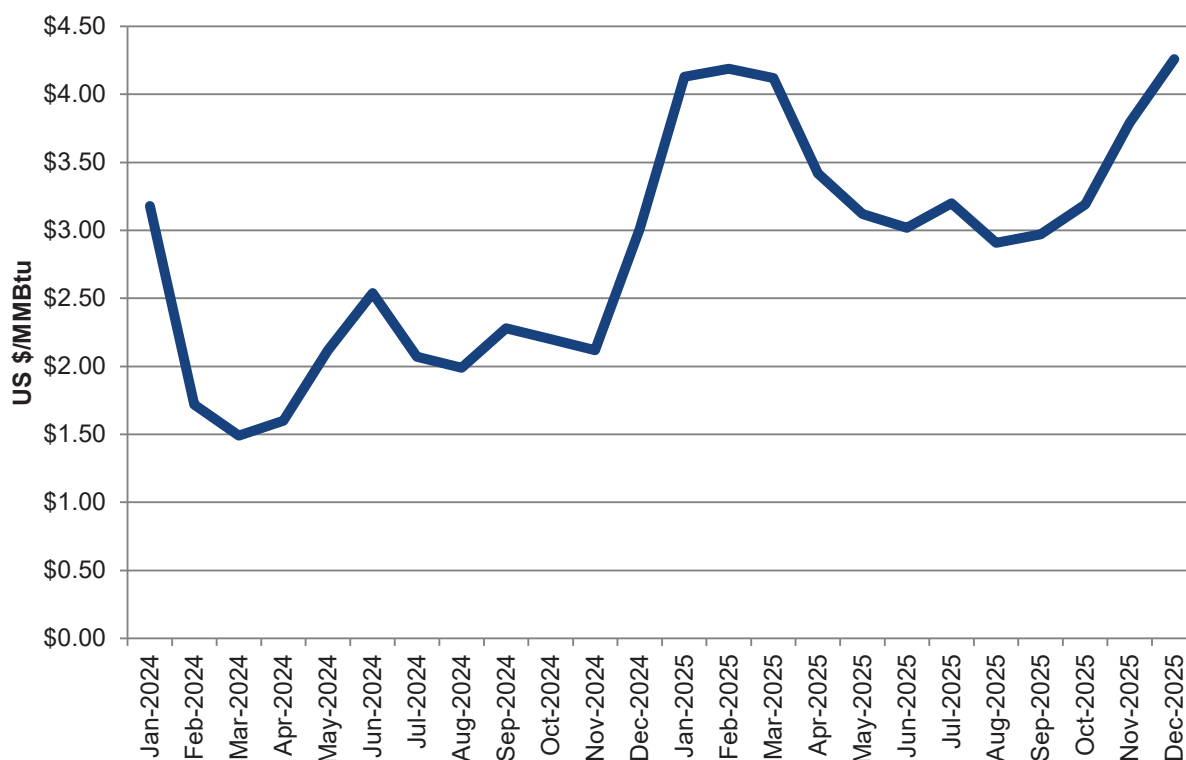
VIII.A. Background

In this chapter, we assess NSPI's natural gas procurement processes and results during the Audit Period. The natural gas market in Nova Scotia remains supply constrained, which limited the number of natural gas suppliers and the availability of natural gas. As a result, NSPI was often a price taker and, at times, purchased all the natural gas made available by its suppliers. NSPI maintains a number of procurement contracts with various counterparties that supply and trade in natural gas. These contracts allow NSPI to purchase natural gas, when available at desirable prices, and to sell excess gas to manage natural gas commitments. NSPI also maintains agreements with financial counterparties to facilitate transactions in natural gas-related derivatives.

This Audit Period was characterized by a mostly gradual and moderate increase in natural gas prices. Prices in 2024 persisted at similar levels to those seen in the prior year and increased during 2025. Using price data for the monthly Henry Hub spot gas contract as an example, the simple average price of natural gas increased by \$1.33 per MMBtu, approximately 61%, from 2024 to 2025.³³² Figure VIII-1, below, illustrates these monthly prices.

³³² Average price in 2024 was \$2.19/MMBtu; average price in 2025 was \$3.53/MMBtu. US EIA, "Henry Hub Natural Gas Spot Price," available at: <https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm>.

Figure VIII-1: Monthly Henry Hub Spot Gas Prices, 2024-2025 (US\$/MMBtu)



The focus of the remainder of this section is on gas procurement decisions and contract management. We start with a summary of NSPI's counterparties, review term and spot gas transactions, and affiliate transactions with Emera Energy.

VIII.B. Findings

A review of NSPI's gas procurement and management practices indicated that NSPI personnel purchased term natural gas using competitive solicitations and selected offers based on lowest expected price at that time. For the April - October 2024 time period, NSPI did not purchase the quantity of term gas specified in the Fuel Manual due to a concern about being able to sell unneeded gas. For the April–October 2025 time period, NSPI decided to not issue an RFP for term gas because it was receiving a Certificate of Variance allowing SO₂ limits to be exceeded, and the expected gas burn was much lower than in previous years. Other transactions in spot gas, obtaining released FT capacity, and fixed price deals appeared to have been conducted at arms-length. Unlike in the prior audit, Bates White found that documentation surrounding gas purchasing and management decisions were detailed and clear. Natural gas transactions by NSPEMI increased markedly from the prior audit period, with numerous transactions in the US and at the US-CA border.

VIII.B.1. Counterparties and Procurement Locations

During the Audit Period, NSPI and NSPEMI had master agreements for natural gas in place with the following counterparties.³³³

Figure VIII-2: NSPI's Natural Gas Master Agreements

Counterparty	Effective Date
	March 7, 2023
	April 19, 2012
	May 1, 2023
	April 8, 2015
	March 17, 2023
	March 3, 2005
	May 4, 2022
	September 13, 2018
	March 28, 2019
	February 12, 2008
	April 1, 2007
	February 14, 2018
	January 22, 2016
	October 26, 2017
	February 15, 2008
	November 1, 2011
	April 15, 2020
	March 17, 2009
	January 1, 2009
	May 27, 2014
	March 26, 2007
	May 12, 2020
	September 21, 2020
	May 28, 2019

During the Audit Period, NSPI and NSPEMI purchased natural gas from the counterparties listed in Figure VIII-3.³³⁴ Gas was purchased at Empress (Alberta), Tufts Cove (Nova Scotia), Baileyville (New Brunswick), and Westbrook (Maine). Purchases of gas at Baileyville and Empress were executed by NSPI. Gas transactions at Westbrook and Baileyville were executed by NSPEMI. There were small transactions at Pittsburg (NH) and Dawn (Ontario) to balance fuel requirements between TCPL and PNGTS. Prices varied throughout the Audit Period (by month, by day, by time of day, and by location).

³³³ NS Power Natural Gas Reports - November 1, 2023, to October 31, 2024, and November 1, 2024, to October 31, 2025, Sections 7.1 in each report. Effective Date is the earlier of NSPI or NSPEMI execution.

³³⁴ NSPEMI (Nova Scotia Power Energy Marketing, Inc.) is a U.S. company, wholly owned by NSPI, that buys and sells electricity and natural gas in the U.S on behalf of NSPI at cost. Gas purchased from NSPEMI is not shown separately.

The quantity of gas purchased by NSPI and NSPEMI varied by month and supplier over the Audit Period. Figure VIII-3 below illustrates the quantities purchased and how the gas supplier mix changed during the Audit Period.

Figure VIII-3: NSPI's Natural Gas Purchases, 2024-2025 (MMBtus)³³⁵

Counterparty	Purchases (MMBtus)		Change		Percent of Portfolio	
	2024	2025	2024 to 2025	% Change	2024	2025

As shown in the above table, the major suppliers in 2024 were [REDACTED], who together supplied [REDACTED] percent of the natural gas consumed by NSPI. By 2025, the major suppliers were [REDACTED] who together supplied [REDACTED] percent of NSPI's natural gas.

With the [REDACTED] (which was executed during the prior Audit Period), the mix of purchase locations changed to include Empress. Except for some seasonal production in [REDACTED]
[REDACTED]³³⁶

VIII.B.2. Term Gas Transactions

Of the gas purchases identified in Figure VIII-3, a significant portion were term deals for periods of up to [REDACTED] months at [REDACTED] prices, in addition to the [REDACTED] term deal with [REDACTED]. Each of the transactions were reviewed and approved by ERM and FST and documented in a Record of Approval ("ROA"). The average daily quantity ranged from [REDACTED]. Some of these term deals were shaped by NSPI to match expected gas demand in the months ahead. The total quantity of gas purchased pursuant to term deals was [REDACTED] MMBtu in 2024 and [REDACTED] MMBtu in 2025. The quantity of gas purchased under term deals in 2024 and 2025 was [REDACTED] percent and [REDACTED] percent of NSPI's

³³⁵ These numbers include fuel gas provided to pipelines as partial payment for the gas transportation charges.

³³⁶ This includes purchases from [REDACTED].

Figure VIII-4: NSPI's Term Natural Gas Purchases, 2024-2025 (MMBtu)

Counterparty	2024	2025
Bank of America	100	100
JP Morgan Chase	100	100
Wells Fargo	100	100
Citigroup	100	100
Bank of Montreal	100	100
TD Bank	100	100
Capital One	100	100
Bank of the West	100	100
US Bank	100	100
First National Bank	100	100
Bank of New York	100	100
Bank of Hawaii	100	100
Bank of Alaska	100	100
Bank of California	100	100
Bank of Texas	100	100
Bank of Florida	100	100
Bank of Georgia	100	100
Bank of South Carolina	100	100
Bank of North Carolina	100	100
Bank of Virginia	100	100
Bank of Maryland	100	100
Bank of Delaware	100	100
Bank of New Jersey	100	100
Bank of Pennsylvania	100	100
Bank of New York	100	100
Bank of Hawaii	100	100
Bank of Alaska	100	100
Bank of California	100	100
Bank of Texas	100	100
Bank of Florida	100	100
Bank of Georgia	100	100
Bank of South Carolina	100	100
Bank of North Carolina	100	100
Bank of Virginia	100	100
Bank of Maryland	100	100
Bank of Delaware	100	100
Bank of New Jersey	100	100
Bank of Pennsylvania	100	100

Figure VIII-5: NSPI's Term Natural Gas Purchases, 2024-2025 (MMBtu)



The majority of term gas was purchased at [REDACTED] while deals with [REDACTED] counterparties were done at [REDACTED]. These were shorter term deals except for a [REDACTED] deal with [REDACTED] in 2024, and a five-month deal with Repsol that ended in March 2025. The prices for these transactions

varied but reflected market conditions. Figure VIII-6 illustrates the marginal cost of gas at Westbrook for the term deals over the Audit Period.

Figure VIII-6: Marginal Costs for Term Natural Gas Purchased at Westbrook, 2024-2025 (USD/MMBtu)



The ROAs were supported by analyses that compared the expected cost of gas delivered to Baileyville between various competitors and made recommendations of how much gas to purchase and from whom. The objective was to obtain the lowest, expected cost of gas. These analyses were well documented by ERM, reviewed and approved by the FST, and supported NSPI's decisions.

VIII.B.2.a. The [REDACTED] Contracts

[REDACTED] primary business in [REDACTED] is importing liquefied natural gas ("LNG") and selling it when prices are attractive. [REDACTED] also [REDACTED] and Canada.³³⁷ When it is not using this [REDACTED] contract, it releases it to third parties, including NSPEMI. As noted in Chapter VII, NSPEMI accepted [REDACTED] term capacity releases from [REDACTED] over the course of the audit period, with the latter [REDACTED] at a discount to the [REDACTED] rate (which was less expensive than the IT capacity available to NSPI).

³³⁷ Enbridge, "Maritimes & Northeast Pipeline, L.L.C.," <https://infopost.enbridge.com/infopost/MNUSHome.asp?Pipe=MNUS>.

██████ also supplied ██████ MMBtu of term gas delivered to Baileyville for the month of November in 2025 pursuant to an October 2025 RFP for gas supply over this period.

VIII.B.2.b. ██████ Contract

NSPI purchased term gas from ██████ pursuant to an August 2024 RFP for the November 2024 to March 2025 period. For the months of ██████, NSPEMI purchased ██████ MMBtu per day from ██████ at ██████ which represented the best offer in the RFP during the months of those offers, but did not include sell-back provisions (the lowest-price offer that contained sell-back provisions was also accepted in this RFP). These bid awards were evaluated against other offers based on price and volume required. These term deals were captured in ROA NG0067.

VIII.B.2.c. ██████ Contract

In the prior Audit Period, NSPI signed a firm gas supply agreement with ██████ of ██████ MMBtu per day, plus fuel, for receipt at Empress, AB. The term ran from ██████, and the transaction was valued at approximately US\$ ██████ million, subject to market changes.

Nearing the conclusion of this contract, NSPI issued an RFP for gas supply delivered to Empress beginning ██████ offered a ██████ deal, which featured the lowest costs for both ██████ among all competing counter offers, in addition to a call option feature. The ██████ offer was ultimately selected, representing an effective renewal of the previous contract ██████. Beginning ██████, NSPEMI has purchased ██████ MMBtu per day, plus fuel, for receipt at ██████ through this contract. This term deal was captured in ROA NG0069.

VIII.B.2.d. ██████ Contract

Following the Q4 2024 PLEXOS forecast, which projected gas consumption for December of that year to be approximately ██████ MMBtu/day, NSPI approached counterparties for up to ██████ MMBtu/day gas supply for the month of ██████ to supplement the ██████ gas supply of ██████ MMBtu/day and baseload supply of ██████ MMBtu/day already purchased for the winter season. ██████ bid was accepted as the lowest-price offer meeting the full supply request over the relevant period. This term deal was captured in ROA NG0068.

VIII.B.2.e. ██████ NG Contract

NSPI signed ██████ term gas contracts with ██████ over the course of the Audit Period. In February of 2024, NSPI issued an RFP, triggered by the Q1 2024 forecast, for gas supply for the ██████ period. ██████ over the requested term was accepted as the lowest-price offer, along with the second-best offer in terms of price from ██████). This term deal was captured in ROA NG0069.

NSPI signed another term gas deal with [REDACTED] for the period from [REDACTED] to [REDACTED]. Similar to the prior deal, NS Power purchased [REDACTED] MMBtu/day from [REDACTED] delivered at [REDACTED]. This deal also represented the lowest-price offer over the full contract term that also featured [REDACTED] to come out of the April 2024 RFP for gas supply over the November 2024–March 2025, period (see Emera Contract section above). This term deal was captured in ROA NG0067.

VIII.B.2.f. [REDACTED] Contract

In addition to the [REDACTED] contract signed pursuant to NSPI's October 2025 RFP for gas supply for [REDACTED], NSPI also signed a contract with [REDACTED] for the month of [REDACTED], delivered to [REDACTED]. The [REDACTED] offers represented the first and second lowest price offers, respectively. This term deal was captured in ROA NG0071.

VIII.B.2.g. [REDACTED] Contract

As noted earlier, NSPI signed a term gas contract with [REDACTED] that arose from a February 2024 RFP for gas supply for the [REDACTED] period. Twin Eagle's offer represented the second-best offer in terms of price, after that of [REDACTED]. For the relevant period, NSPEMI purchased [REDACTED] MMBtu/day from [REDACTED] delivered at [REDACTED]. This term deal was captured in ROA NG0069.

VIII.B.2.h. No RFP Issued for the 2025 Summer Period

On February 24th, 2025, NSPI issued an RFP seeking gas supplies for the April–October 2025 time period based on the Q1 2025 forecast. Following RFP issuance, on March 12, 2025, NSPI met with the Nova Scotia Department of Environment and Climate Change (NS ECC), who indicated their intent to provide SO₂ air emission compliance relief in the form of a Certificate of Variance (CoV) to provide emissions flexibility in the 2025–2027 timeframe. A subsequent PLEXOS forecast indicated that no additional gas would be required beyond the [REDACTED] MMBtu/day under contract with BP to meet the [REDACTED] percent of gas consumption target required by the Fuel Manual. The additional gas forecasted to be procured ranged from a low of [REDACTED]/day in May 2025 to a high of [REDACTED]/day in August 2025. NSPI expected these quantities to be readily available on spot market and subsequently withdrew the RFP.

VIII.B.2.i. Selling Gas at Other Locations

In the previous Audit Period, most of NSPI's gas resales were at Baileyville. This meant that the realized price would reflect the additional cost a buyer would incur to move the gas to a different market. During the current Audit Period, NSPEMI also sold gas at other locations in New Hampshire (Pittsburg) and Maine (Westbrook). Notable transactions with [REDACTED] occurred between March 20, 2025, and March 29, 2025, when NSPEMI sold between [REDACTED] MMBtu/day to [REDACTED] MMBtu per day at Westbrook. The reasons for these sales were not covered explicitly in the Shift Reports, but the gas blotters for these dates indicated that a number of the Tufts Cove units were offline. NSPI sold gas in AB and ONT.

VIII.B.2.j. The Effect of Contracting for Firm Term Gas

The term gas purchases were generally firm, which meant that NSPI could not contractually vary its daily gas purchases. Failure to take the gas would not necessarily be a breach of the base North American Energy Standards Board (NAESB) contract, but failure to take firm gas could be considered non-performance and trigger payment of remedies to keep the gas supplier whole. As discussed in the previous audit, the base NAESB contracts NSPI/NSPEMI held with its term gas suppliers all elected the “Cover Standard” in the event of non-performance by either party.³³⁸ Accordingly, if the term gas under contract exceeded NSPI’s requirements on any one day, it would have four options – buy the gas and re-sell it, not take the gas and pay the liquidated damages, pack it on the pipeline, or reduce purchases from another gas contract that allowed variable daily purchases.

The operating pressure on the Tennessee Gas Pipeline is lower than the operating pressure on M&NE-US. Using IT or its PNGTS FT capacity, NSPEMI is in a position to directly sell unneeded gas into markets served by Tennessee or into Algonquin via displacement.

NSPEMI had previously stated that there was a tax issue associated with selling gas in Massachusetts,³³⁹ but has since confirmed they are able to transact in other states. Further, the primary delivery point for NSPI’s PNGTS FT contract is Dracut, MA, the interconnection with TGP.³⁴⁰ A sale of unneeded gas into the TGP market can be made by changing the nominated delivery point on their PNGTS contract from Westbrook to Dracut.³⁴¹ Bates White noted that gas prices in Algonquin Citygates (“AGT-CG”) and Tennessee Gas Pipeline Zone 6 (“TGP Z6”) topped US\$20 per MMBtu on a number of days during the Audit Period.³⁴² These types of price events could make an attractive market for NSPEMI provided there was not a physical need for gas by NSPI. At high gas prices, it could make economic sense to sell gas and burn HFO and generate a positive gross margin for FAM customers.

VIII.B.3. Prices Paid by NSPI for Spot Natural Gas

For most of the Audit Period, NSPI captured its natural gas-related transactions in a software application called Allegro (also known as Horizon). Each transaction was assigned an individual number, and identified the counterparty, date of trade, term of the transaction, quantity of gas, price paid, product type, and delivery point. NSPI also sometimes captured gas market information in daily traders’ logs, but more detailed operational information was captured in the Shift Reports. The trades typically were entered into Allegro on the day they were executed, but not necessarily in the order they were executed.

³³⁸ NAESB, “Base Contract for Retail Sale and Purchase of Natural Gas or Electricity,” pages 2-3, <https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.naesb.org%2Fpdf2%2Fupdate011806w4.doc&wdOrigin=BROWSELINK>.

³³⁹ 2022-2023 Bates White Audit Report, page 182.

³⁴⁰ See PNGTS tariff, Index of Customers.

³⁴¹ The PNGTS tariff provides for five nomination changes – two prior to the day of gas flow and three during the day of gas flow. See PNGTS Tariff Section 6.7.2.

³⁴² AGT and TGP prices were compiled from S&P Capital IQ.

Accordingly, the Allegro number cannot be used to determine the order of the trades, and whether the lower cost trades were executed first. However, notes in tab “Real Time” in the gas traders’ blogs provided some help in determining NSPI’s gas purchase decisions. However, most of the gas trading comments appear to be more focused on changes caused by plant operations and less so on market conditions. Prior to the gas trader’s commentary referencing the Shift Reports, there were typically daily comments in the gas traders’ blogs about the gas market conditions, counter-party conversations, why offers were accepted or not, and screen shots of real-time pricing in relevant natural gas markets.

NSPI lost access to Allegro for a few months following the cyber event. During this period, NSPI relied on the daily gas trade blotters to track all trades up to and including settlement. Specifically, the gas trade blotters were provided to the finance group at the end of the month, who would reconcile the transactions captured within as compared to counterparty invoices. In effect, the gas trade blotters substituted for the report that otherwise would be generated out of Allegro. This process continued uninterrupted following the cyber event until Allegro was restored. At this point, NSPI went back and re-entered the trade data from the interim period into Allegro and returned to normal usage of the software for the remainder of the Audit Period.

The actual prices at which natural gas purchases and sales were transacted between NSPI and its counterparties appeared to be the result of arm’s length negotiations. Reviewing the prices paid to various counterparties, the prices appeared correlated with market indices or conditions and reflected the mutual agreement of NSPI and its counterparties. Accordingly, we conclude that NSPI bought natural gas at market prices in the NB/NS/ME natural gas market.

VIII.B.4. Pipeline Balancing

As part of its daily natural gas management activities, NSPI was responsible for managing its transactions on M&NE-CA. NSPI nominated to M&NE-US and M&NE-CA the amount of gas it wanted to transport from one point to another. The pipeline tariff required that NSPI stay close to that nominated quantity, within allowable tolerance, which was applied to the aggregate of the nominations to meters where NSPI was the “meter operator.”³⁴³ If there was too much gas, then NSPI either parked some gas on the pipeline, sold gas to a counterparty, burned it, or did nothing and possibly incurred a penalty. If there was too little gas, then NSPI attempted to buy gas late-day or intra-day, drafted some gas from the pipeline, curtailed its use of gas, or did nothing and possibly incurred a penalty.³⁴⁴

Some of the operational issues that triggered a potential imbalance included the unplanned use of gas by the biomass plant, the Energy Control Centre (“ECC”) changing the day’s schedule, wind generation outside of expected range, unplanned outages at generation facilities, and lower than needed gas pressure

³⁴³ This is a term used by the pipeline to identify the party responsible for balancing at a meter.

³⁴⁴ Enbridge, “M&NE-CA Tariff General Terms and Conditions,” <https://infopost.enbridge.com/infopost/MNCAHome.asp?Pipe=MNCA>.

at Tufts Cove. The Shift Reports demonstrated NSPI's awareness of the difference in the "gas day" and "electric day," and documented operators coordinating to use scheduled gas accordingly or request that gas be purchased or sold.³⁴⁵

Imbalances on M&NE-CA were cashed out monthly but were calculated on the absolute value of the daily imbalance and the accumulation of the actual daily imbalances. The imbalance cost had three tiers: 0-5%, 5-10%, and greater than 10%. Tier 1 had no charge, Tier 2 was charged \$0.228 per GJ, and Tier 3 was charged \$0.4562 per GJ.³⁴⁶ Using December 2024 to illustrate, NSPI saw daily gas imbalances that ranged from a 1,861 GJ pack to an 11,297 GJ draw on the pipeline. On an absolute value basis, this totaled to a 48,329 GJ imbalance at a cost of \$3,319.23. The value of the cumulative daily imbalance was 108,361 GJ at a cost of \$1,280.63. When the total of these imbalance charges of \$4,599.86 was applied to the quantity of gas consumed for the month (1,039,979 GJ), the effect was \$0.0044 per GJ. While minimal, this does illustrate that there was a cost associated with managing the gas supply in real time. This cost effect does not include the cost of any gas that had to be purchased or sold to bring the imbalance within tariff limitations.

VIII.C. Review of Transactions with Emera Energy

VIII.C.1.a. Estimating the Fair Market Value of NSPI's Natural Gas Purchases from Emera

NSPI's natural gas transactions with Emera Energy, Inc. are subject to NSPI's Code of Conduct ("Code") regarding affiliate transactions. The Code requires that NSPI, when transacting with Emera Energy,

"pay...a price for each Affiliate Transaction no more than [Fair Market Value] or its self-provisioning costs, whichever is less. If [Fair Market Value] cannot be determined, NS Power will pay an Affiliate a price for each Affiliate Transaction no more than the Affiliate's [Fully Allocated Costs] or NS Power's self-provisioning costs, whichever is less."³⁴⁷

The Code goes on to describe how NSPI should determine the Fair Market Value of an affiliate transaction.

"NS Power and its Affiliates shall determine and document prices based on [Fair Market Value] through the use, where practicable, of offers from competitive tendering or quotes from a minimum of two alternative qualified third-party suppliers. Otherwise, NS Power and its Affiliates shall use the most direct alternative means of establishing [Fair Market Value] prices, including without

³⁴⁵ The electric day spans 24 hours starting at 12 AM and the gas day spans 24 hours starting at 9 AM Central time. Natural Gas Intel, "FERC Final Rule Retains 9 a.m. CST Gas Day Start Time", April 16, 2015, available at: <https://www.naturalgasintel.com/ferc-final-rule-retains-9-a-m-cst-gas-day-start-time/>.

³⁴⁶ These are one-half and full FT rate, respectively.

³⁴⁷ Code of Conduct, section 6.2.1.

limitation benchmarking studies, surveys, catalog pricing or recent market transactions.”³⁴⁸

In order to evaluate NSPI’s compliance with the Code in its natural gas transactions with Emera Energy during the Audit Period, a threshold question must be addressed: What is the definition of the natural gas market in which the transactions with Emera Energy occurred? The remainder of this section describes the approach used by Bates White to address the threshold question and evaluates whether NSPI followed the requirements of the Code in determining the FMV of its natural gas transactions with Emera Energy. NSPI had two different types of natural gas transactions with Emera Energy: (1) spot gas transactions, and (2) term transactions. Spot transactions typically ranged from less than a day to a few days. Term transactions ranged up to five months.

VIII.C.1.b. Market Definition and Price Determination

During the Audit Period, NSPEMI’s market area for natural gas included portions of New England and locations accessed by TCPL across Canada. As described in NSPI’s 2025 Natural Gas Report, NS Power continues to [REDACTED] from New England due to pipeline capacity constraints in the region.³⁴⁹ Transactions with counterparties occurred regularly at Baileyville and Westbrook.

VIII.C.1.c. Fair Market Value

In the absence of pipeline constraints, commodity price determination in natural gas markets is often a result of arbitrage. If a seller can obtain a higher net margin by transporting gas to another market, then that will put upward pressure on local prices. Conversely, if a buyer can obtain a lower price buying gas in a different market and transporting it, that will exert downward pressure on local prices. On a daily basis, prices settle across different markets when no buyer or seller can obtain a better outcome by moving gas, at the marginal cost of transportation, to another market. This dynamic is observable in the prices on electronic platforms, such as the Intercontinental Exchange (“ICE”), and in NSPI’s communications with other traders.

However, in capacity constrained markets, natural gas prices between various locations can differ by more than the marginal cost to transport gas from one market to another. When this price differential (also known as a basis differential) is greater than the marginal cost of transportation, the incremental difference reflects the value of pipeline capacity between the two markets. This is often the case during the winter months between the AGT-CG and New York Mercantile Exchange (“NYMEX”) prices, and between NSPI’s market and AGT-CG prices, when the basis differential spikes because the demand for natural gas exceeds the available pipeline capacity. Natural gas prices can also be influenced by a counterparty’s access to an alternate fuel or generation source that might cap the price of natural gas.

³⁴⁸ Code of Conduct, section 6.2.2.

³⁴⁹ See, for example, November 1, 2024 to October 31, 2025 Natural Gas Report, page 12, lines 16-18.

For spot gas transactions, NSPI/NSPEMI interacted directly with counterparties, on a daily basis and throughout the day, to determine available quantities and associated prices, which were often tied to published price indices (e.g., AGT-CG, TGP Dracut/Z6, etc.).³⁵⁰ Other spot transactions were negotiated with counterparties. Delivery locations were typically at Baileyville or Westbrook, with some gas purchased on a delivered basis to Tufts Cove. Gas purchased at Baileyville and Westbrook incurred additional pipeline charges to transport it to Tufts Cove.

Prices varied from day to day and within the Gas Day, reflecting the changing supply and demand conditions. For example, typical natural gas products include Next Day, Late Day, and Intra Day, which reflect when during the pipeline nomination cycle the transaction was confirmed. These different products often have different prices.

VIII.C.1.d. Prices Paid by NSPI to Emera for Spot Natural Gas

This section covers spot gas transactions with Emera Energy. NSPI's term gas purchases from Emera Energy are discussed in section VIII.B.2.b. We reviewed the spot transactions between NSPI and Emera Energy to evaluate whether, and to what extent, the prices paid by NSPI varied materially from those it paid to other counterparties. For each day on which NSPI purchased gas from Emera Energy, we compared the highest price paid to other suppliers to the price paid to Emera Energy. This was done separately for each location and for each of the gas products purchased. Bates White identified NSPI transactions with Emera Energy at Westbrook and Baileyville for Next-Day, Intra-Day, and Late-Day gas. For each day, gas was purchased from Emera Energy, the traders' logs and daily trades were reviewed to examine the reasons for the transaction. Note that the gas trader blogs calculated the delivered cost of gas to Tufts Cove making comparisons more transparent.³⁵¹ Bates White identified 68 transactions where the price paid to Emera Energy was the highest price paid that day for a given gas product, other than when Emera Energy was the only available counterparty. The price differences were explained by:

- NSPI purchased the lowest cost gas first, then Emera Energy was the next lowest cost offer.
- Other counterparties did not have any gas available, or gas was offered at a price higher than transacted with Emera Energy.

As Figure VIII-7 below illustrates, the average prices paid to Emera Energy for Next Day Gas, Intra-Day Gas, and Late-Day Gas were lower than the average of the highest prices paid to other counterparties.³⁵²

³⁵⁰ Natural gas prices are surveyed and published daily and monthly for various gas market locations, which are defined by the respective publications. Natural gas is also traded electronically on ICE – the Intercontinental Exchange.

³⁵¹ This changed in the latter part of 2019 when the traders' blog started showing the delivered cost of gas to Tufts Cove.

³⁵² Please note that the average values in this table are the averages of weighted averages, calculated separately. Accordingly, the price differences cannot be calculated directly from the table values.

Figure VIII-7: Comparison of Prices Paid to Emera and All Suppliers

	Average High Price Paid to All Suppliers	Average Price Paid to Emera	Difference
Late-Day Trades at Baileyville			
Next Day Trades at Baileyville			
Intra-Day Trades at Baileyville			

In the 2020-2021 audit period, we had examined all transactions at Tufts Cove where Emera Energy appeared to be the only counterparty. These transactions were in line with NSPI buying natural gas at market prices. As with the previous audit period (2022-2023), there were no instances of these transactions during the Audit Period.

VIII.C.1.e. Evaluation of Fair Market Value When No Counterparties Other than Emera Energy Were Available

NSPI has adopted an affiliate transaction tracking protocol for natural gas transactions with Emera Energy as one approach to demonstrate its compliance with the Code. The rationale to this approach appears to be that as long as the price paid to Emera Energy is less than the next available gas deal delivered to Tufts Cove, then the Emera Energy transaction would satisfy the Fair Market Value standard and provide a benefit to FAM customers. NSPI also does not award “ties” to Emera Energy unless additional gas is needed.³⁵³ We generally agree with this approach, provided like alternatives are compared (e.g., Next Day to Next Day, Late Day to Late Day, etc.).

We observed that this approach was consistent with our understanding of how natural gas prices are determined in a capacity-constrained, natural gas market and with principles of least-cost dispatch.

VIII.C.1.f. Visual Representations of Spot Trade Purchases from Emera

The figures below compare the purchase prices of spot natural gas from Emera against purchases from non-affiliated counterparties on the same day, if available. As discussed above, purchases from Emera Energy were generally lower than the prices paid to other counterparties or occurred on days without purchases from other counterparties.

³⁵³ 2022-2023 Bates White Audit Report, page 188.

Figure VIII-8: Late Day Trades at Baileyville (2024)



Figure VIII-9: Late Day Trades at Baileyville (2025)



Figure VIII-10: Next Day Trades at Baileyville (2024)



Figure VIII-11: Next Day Trades at Baileyville (2025)



Figure VIII-12: Intra Day Trades at Baileyville (2024)



Figure VIII-13: Intra Day Trades delivered to Baileyville (2025)



VIII.D. Bates White's 2022-2023 Recommendations

In its previous Audit Report, Bates White made five recommendations related to natural gas procurement.³⁵⁴

Our first recommendation was:

Recommendation VIII-1: Develop the ability to sell and buy gas at Dawn and into the Algonquin and Tennessee Gas pipeline markets.

NSPI accepted this recommendation, stating that “[o]pportunities to expand market access will be investigated and enacted where possible.”³⁵⁵ We noted in our February 21, 2025 Rebuttal Evidence that “[t]his response does not fully address the recommendation, which recommends that NSPI develop its ability to sell and by gas into the Algonquin and Tennessee Gas pipeline markets, not merely to ‘investigate’ additional ‘market access[opportunities].’”³⁵⁶ In their February 2026 Update, NSPI confirmed that it both “developed the ability to buy and sell gas into the Dawn market” and that “NS Power/NSPEMI is now able to transact in Massachusetts providing access to the Algonquin and Tennessee Gas pipeline markets.” As such, we consider this recommendation fully addressed.

Our second recommendation was:

Recommendation VIII-2: As part of the daily gas blogs, track the market prices at other markets accessible to NSPEMI and rank the net margins associated with each in the event NSPEMI had to sell unneeded gas. Further, provide relevant gas market information not found in the Shift Reports.

NSPI accepted this recommendation,³⁵⁷ and confirmed in their February 2026 Update that “NS Power has developed daily market gas prices tracking and ranking, in the event NSPEMI has to sell unneeded gas.” Bates White considered NSPI’s response to be “positive and satisfactory.”³⁵⁸ As noted before, we observed the inclusion of the requested tracking and information in NSPI’s gas trader blotters. As such, we consider this recommendation fully addressed.

Our third recommendation was:

Recommendation VIII-3: As part of its role in managing the gas resource portfolio, NSPEMI should identify and document additional ways of minimizing costs by utilizing the tariff provisions of their pipeline contracts to minimize transportation costs or sell unneeded gas at the highest available net margin.

³⁵⁴ 2020-2021 Bates White Audit Report, page 171.

³⁵⁵ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³⁵⁶ Bates White’s February 21, 2025 Rebuttal Evidence, page 6 lines 19-20, page 7 line 5.

³⁵⁷ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³⁵⁸ Bates White’s February 21, 2025 Rebuttal Evidence, page 6 lines 19-20, page 7 line 5.

NSPI accepted this recommendation and furthered that it “will be addressed through the response to Recommendation VIII-5.”³⁵⁹ As such, we have assessed whether this recommendation has been fully addressed alongside our assessment of Recommendation VIII-5 below.

Our fourth recommendation was:

Recommendation VIII-4: NSPEMI and NSPI should provide reviewable documentation in ROAs and gas blogs regarding significant gas management decisions.

NSPI accepted this recommendation,³⁶⁰ and confirmed in their February 2026 Update their intention to “increase documentation to include significant decisions on gas supply management not previously captured.” Bates White considered NSPI’s response to be “positive and satisfactory.”³⁶¹ As compared to prior audit periods, we observed the provision of more documentation pertaining to significant gas management decisions in NSPI’s ROAs and daily gas blotters. For example, nearly all ROAs included detailed recommendation memos from ERM that provided background and summary information. As such, we consider this recommendation fully addressed.

Our fifth recommendation was:

Recommendation VIII-5: NSPEMI and NSPI should, as part of the term gas purchase programs and real time gas management, evaluate and document whether it is more economic to contract for some term gas with sell-back provisions, sell un-needed gas into one or more markets, or not take gas and pay liquidated damages.

NSPI accepted this recommendation, stating that “RFP memos will document the consideration of the alternatives available for reducing gas volumes should the need arise during the term of the gas supply” and that “[in] real time when a reduction in gas volume is required, the alternatives considered will be documented in the gas blotter.”³⁶² We noted in our February 21, 2025 Rebuttal Evidence that “[t]hese commitments are positive, but it may be worthwhile to ensure these enhancements are implemented by a date certain and to introduce a period of regulatory reporting to ensure the recommendations have been implemented in full.”³⁶³ In their February 2026 Update, NSPI stated that it “tracks the alternatives for reducing supply in the daily gas blotter to provide justification for the actions taken when needed.” It furthered that “[l]imited natural gas reselling activities have been required since this recommendation has been accepted...[and] would recommend the review of the analysis be deferred until there is actual market transactions to better demonstrate the methodology.” Bates White finds this acceptable at this time, provided that NSPI self-report on gas sales identifying the terms of the transaction, why the counterparty was selected, how the price was agreed to, and why a particular location was selected.

³⁵⁹ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³⁶⁰ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³⁶¹ Bates White’s February 21, 2025 Rebuttal Evidence, page 6 lines 19-20, page 7 line 5.

³⁶² NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.10.1.

³⁶³ Bates White’s February 21, 2025 Rebuttal Evidence, page 6 lines 19-20, page 7 line 5.

VIII.E. Conclusions

Conclusion VIII-1: NSPI managed its natural gas purchases in a reasonable manner, worked to negotiate the lowest prices in a market where they were often a price taker, and documented term transactions.

Conclusion VIII-2: Each of the spot gas and term gas transactions between NSPI and Emera Energy were examined, and there was no apparent bias or favoritism towards Emera Energy observed. These natural gas transactions appeared to be in compliance with the Code and done at fair market value.

Conclusion VIII-3: NSPEMI continued selling and purchasing gas in the United States and exporting it to Canada during the Audit Period.

Conclusion VIII-4: In 2024, NSPI burned an average of [REDACTED] MMBtu per day and a maximum daily burn of [REDACTED] MMBtu. In 2025, NSPI burned an average of [REDACTED] MMBtu per day, with a maximum daily burn of [REDACTED] MMBtu.

Conclusion VIII-5: In addition to gas sold at Baileyville, NSPEMI and NSPI sold gas at various points in Canada, NH, and Maine.

Conclusion VIII-6: NSPI has adequately addressed our natural gas procurement-related recommendations from the 2022-2023 Audit Report but note that a portion of Recommendation VIII-5 regarding the evaluation of reducing gas purchases appears to remain outstanding. (**Recommendation VIII-1**)

VIII.F. Recommendations

Recommendation VIII-1: Provide monthly documentation of gas sales by NSPEMI and NSPI (excluding transactions between NSPEMI to NSPI) identifying the terms (e.g., quantity, location, price, etc.) of the transaction, why the counterparty was selected, how the price was agreed to, and why a particular title transfer location was selected.

VIII.G. Appendix: Emera Spot Gas Purchases Overview

Figure VIII-14: Late Day Trades delivered to Baileyville

Trade Date	Trade ID	Trade Class	Point	Counterparty	Natural Gas Price	Daily Maximum Price	Daily Maximum Price Less Emera NG Price	Number of Trades on same day	Summary of Gas Traders' Blog Notes
1/29/2024	602435	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$8.75	\$8.75	\$0.00	1	
3/14/2024	611404	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.05	\$2.10	\$0.05	2	
3/21/2024	612773	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.00	\$0.00	2	
3/25/2024	613435	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.70	\$2.75	\$0.05	2	
4/2/2024	615228	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.55	\$2.85	\$0.30	3	
4/3/2024	615584	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.70	\$2.70	\$0.00	1	
5/19/2024	625580	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.25	\$0.25	2	
5/24/2024	627021	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	2	
5/26/2024	627090	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	2	
6/30/2024	635229	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.75	\$2.75	\$0.00	3	
7/19/2024	703604	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.85	\$2.85	\$0.00	1	
7/24/2024	704872	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.40	\$3.40	\$0.00	3	
7/25/2024	705197	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.45	\$2.50	\$0.05	2	
8/15/2024	710047	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.70	\$0.05	2	
8/27/2024	712207	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.80	\$2.80	\$0.00	3	
9/11/2024	715144	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.75	\$2.75	\$0.00	1	
9/14/2024	715488	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$2.50	\$2.50	\$0.00	1	
11/16/2024	732324	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.00	\$0.00	1	
12/9/2024	733288	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.50	\$5.50	\$0.00	1	
12/15/2024	734548	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$8.00	\$8.00	\$0.00	1	
1/1/2025	738339	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.75	\$3.75	\$0.00	1	
1/17/2025	742263	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$20.00	\$21.00	\$1.00	3	
1/30/2025	745509	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$16.50	\$18.00	\$1.50	4	
2/19/2025	750267	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$17.00	\$17.00	\$0.00	3	
2/23/2025	751061	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$9.50	\$11.50	\$2.00	3	
3/18/2025	756365	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$4.30	\$4.30	\$0.00	1	
3/19/2025	756617	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$4.40	\$4.40	\$0.00	1	
4/2/2025	759507	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$4.25	\$4.50	\$0.25	2	
5/6/2025	771471	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.60	\$3.60	\$0.00	1	
5/9/2025	771472	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.60	\$3.60	\$0.00	1	
5/20/2025	771538	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	2	
5/29/2025	779004	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.15	\$3.15	\$0.00	1	
6/4/2025	774927	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	3	
6/5/2025	773911	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.00	\$5.00	\$0.00	4	
6/12/2025	773897	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.65	\$0.65	3	
6/13/2025	774804	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.00	\$0.00	1	
7/6/2025	779001	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.25	\$5.25	\$0.00	1	
7/14/2025	780728	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$9.50	\$9.50	\$0.00	2	
7/19/2025	782432	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.50	\$5.50	\$0.00	3	
7/20/2025	782427	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.50	\$5.50	\$0.00	2	
7/21/2025	782415	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$4.80	\$4.90	\$0.10	3	
7/24/2025	783646	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.70	\$5.75	\$0.05	2	
7/28/2025	784197	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$7.50	\$7.50	\$0.00	5	
8/4/2025	786265	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$4.75	\$4.75	\$0.00	2	
8/6/2025	786525	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$5.00	\$5.00	\$0.00	1	
9/14/2025	794474	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$3.05	\$3.05	\$0.00	2	
11/19/2025	809835	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$6.70	\$6.70	\$0.00	1	
11/20/2025	809302	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$7.50	\$7.50	\$0.00	1	
12/7/2025	812915	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$17.50	\$17.50	\$0.00	1	
12/20/2025	817140	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$7.25	\$7.25	\$0.00	3	
12/23/2025	817985	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$10.20	\$10.20	\$0.00	2	
12/25/2025	817541	NG Late Day	BAILEYVILLE	Emera Energy L.P.	\$14.00	\$14.00	\$0.00	2	

Figure VIII-15: Next Day Trades delivered to Baileyville

Trade Date	Trade ID	Trade Class	Point	Counterparty	Natural Gas Price	Daily Maximum Price	Daily Maximum Price Less Emera NG Price	Number of Trades on same day	Summary of Gas Traders' Bid Notes
1/10/2024	59786	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.00	\$5.10	\$0.10	3	
1/23/2024	600452	NG Next Day	BAILEYVILLE	Emera Energy L.P.		\$5.90	\$0.40	3	
1/31/2024	602433	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.25	\$6.60	\$0.35	3	
2/9/2024	604533	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.40	\$3.50	\$0.10	3	
2/10/2024	604770	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.10	\$3.20	\$0.10	3	
2/23/2024	607199	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	3	
3/2/2024	608928	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.56	\$0.26	5	
3/8/2024	609981	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.40	\$0.10	5	
4/4/2024	615227	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.70	\$2.75	\$0.05	2	
4/9/2024	616247	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.15	\$2.36	\$0.21	2	
4/10/2024	616524	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.15	\$0.05	3	
4/20/2024	618818	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.85	\$1.90	\$0.05	3	
5/1/2024	621014	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.85	\$1.90	\$0.05	2	
5/10/2024	623216	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$2.10	\$0.15	2	
5/14/2024	623869	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$2.00	\$0.05	3	
5/25/2024	628849	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$2.15	\$0.20	4	
5/29/2024	627394	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$1.95	\$0.00	4	
5/30/2024	627738	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.85	\$1.85	\$0.00	3	
6/1/2024	628536	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.80	\$1.80	\$0.00	3	
6/4/2024	628819	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.15	\$2.20	\$0.05	3	
6/5/2024	629163	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.10	\$0.10	3	
6/8/2024	630238	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.80	\$1.80	\$0.00	3	
6/14/2024	631551	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.35	\$0.00	2	
6/27/2024	634343	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.55	\$2.60	\$0.05	3	
7/1/2024	634856	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.50	\$0.30	2	
7/2/2024	635323	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.30	\$0.10	2	
7/3/2024	635557	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.16	\$0.06	4	
7/4/2024	700312	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.90	\$1.96	\$0.06	4	
7/9/2024	700899	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.20	\$3.35	\$0.15	3	
7/10/2024	701257	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.30	\$0.05	3	
7/13/2024	702202	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.00	\$4.38	\$0.38	5	
7/18/2024	703064	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.00	\$4.00	\$0.00	1	
7/20/2024	703601	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.05	\$2.10	\$0.05	2	
7/23/2024	703931	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.70	\$0.05	2	
7/24/2024	704288	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	2	
7/26/2024	704870	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.66	\$0.01	3	
7/27/2024	705196	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.40	\$2.40	\$0.00	1	
7/30/2024	705630	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.30	\$3.30	\$0.00	1	
8/2/2024	706590	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.50	\$2.60	\$0.10	3	
8/6/2024	707241	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.50	\$0.50	2	
8/7/2024	707545	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.00	\$0.00	1	
8/8/2024	707864	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.00	\$0.00	1	
8/9/2024	708181	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.00	\$0.00	4	
8/10/2024	708544	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.15	\$0.15	2	
8/13/2024	708928	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.35	\$0.25	2	
8/14/2024	709213	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	1	
8/15/2024	709497	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.15	\$2.20	\$0.05	2	

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8/16/2024	709775	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.40	\$0.05	2
8/17/2024	710044	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.30	\$0.05	4
8/20/2024	710384	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.41	\$0.16	5
8/21/2024	710637	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.25	\$0.25	4
8/22/2024	710848	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.00	\$2.31	\$0.31	4
8/23/2024	711100	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.15	\$2.25	\$0.10	3
8/24/2024	711668	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	4
8/27/2024	711672	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.75	\$0.10	4
8/28/2024	711962	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.80	\$2.80	\$0.00	3
8/29/2024	712208	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.15	\$2.15	\$0.00	3
8/30/2024	712468	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$2.50	\$0.55	7
8/30/2024	712750	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.50	\$0.40	7
8/30/2024	712751	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.50	\$0.40	7
8/30/2024	712777	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.50	\$2.50	\$0.00	7
9/4/2024	713674	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.40	\$2.40	\$0.00	3
9/5/2024	713668	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.35	\$0.00	2
9/6/2024	713675	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.40	\$0.15	2
9/6/2024	714017	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.40	\$2.40	\$0.00	2
9/7/2024	714016	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	2
9/7/2024	714019	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	2
9/10/2024	714252	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.20	\$2.20	\$0.00	2
9/11/2024	714485	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.40	\$0.15	2
9/12/2024	714787	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.25	\$0.00	2
9/13/2024	715143	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.25	\$0.00	2
9/14/2024	715404	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.40	\$0.15	3
9/17/2024	715814	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.25	\$0.00	2
9/18/2024	716041	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.35	\$0.00	4
9/19/2024	716377	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.35	\$0.00	4
9/20/2024	716620	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.30	\$0.05	3
9/21/2024	717105	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.30	\$0.00	1
9/24/2024	717471	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.50	\$2.60	\$0.10	4
9/25/2024	717827	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.75	\$2.75	\$0.00	3
9/28/2024	718191	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.70	\$2.70	\$0.00	1
10/11/2024	721554	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.35	\$2.40	\$0.05	3
10/16/2024	722380	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.55	\$2.55	\$0.00	1
10/17/2024	723231	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.75	\$2.75	\$0.00	4
10/18/2024	722933	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.75	\$0.45	6
10/18/2024	723233	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.75	\$0.45	6
10/18/2024	723295	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.75	\$2.75	\$0.00	6
10/24/2024	724021	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.10	\$2.12	\$0.02	2
10/29/2024	724878	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.50	\$2.55	\$0.05	3
10/30/2024	725196	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.25	\$2.40	\$0.15	3
11/3/2024	728241	NG Next Day	BAILEYVILLE	Emera Energy Services, Inc.	\$1.75	\$1.75	\$0.00	1
11/7/2024	726918	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$1.95	\$0.00	1
11/9/2024	727458	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$1.65	\$1.80	\$0.15	6
12/7/2024	732657	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$9.85	\$10.00	\$0.15	4
12/10/2024	733028	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.60	\$5.75	\$0.15	4
12/11/2024	733285	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.50	\$7.00	\$0.50	3
12/11/2024	733287	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$7.00	\$7.00	\$0.00	3
12/14/2024	734178	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$9.50	\$9.77	\$0.27	8
12/27/2024	737266	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$9.50	\$9.50	\$0.00	1
12/28/2024	737256	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$7.00	\$8.76	\$1.76	4
12/28/2024	737257	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$8.50	\$8.76	\$0.26	4
1/1/2025	737910	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.50	\$6.50	\$0.00	4

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1/1/2025		737911	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.40	\$6.50	\$0.10	4
2/27/2025		751805	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.75	\$5.85	\$0.10	7
2/28/2025		752138	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.70	\$5.79	\$0.09	7
3/6/2025		753352	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.00	\$5.00	\$0.00	1
3/11/2025		754170	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.85	\$4.85	\$0.00	4
3/12/2025		754533	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.80	\$4.93	\$0.13	5
3/13/2025		754917	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.10	\$5.10	\$0.00	5
3/14/2025		755164	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.70	\$4.80	\$0.10	3
4/8/2025		760126	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.40	\$6.50	\$0.10	3
4/17/2025		762112	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.35	\$3.45	\$0.10	4
4/18/2025		762413	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.15	\$3.45	\$0.30	5
4/27/2025		772738	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.20	\$3.30	\$0.10	3
5/1/2025		776762	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.10	\$3.15	\$0.05	6
5/3/2025		776776	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.30	\$0.05	4
6/14/2025		773895	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.75	\$0.10	3
6/18/2025		774892	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.30	\$0.05	3
6/29/2025		777450	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	2
7/12/2025		780363	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.75	\$4.75	\$0.00	2
7/15/2025		780738	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$8.50	\$8.50	\$0.00	3
7/18/2025		781338	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$7.00	\$7.05	\$0.05	3
7/25/2025		783662	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.50	\$6.75	\$0.25	4
7/29/2025		784148	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.75	\$7.25	\$0.50	3
7/30/2025		784195	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$7.00	\$7.25	\$0.25	5
8/1/2025		785055	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.10	\$4.10	\$0.00	2
8/5/2025		786258	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.50	\$4.60	\$0.10	5
8/6/2025		786267	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.70	\$4.75	\$0.05	4
8/9/2025		786822	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.50	\$5.65	\$0.15	3
8/12/2025		787808	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$7.00	\$8.00	\$1.00	5
8/14/2025		788172	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.90	\$5.25	\$0.35	6
8/14/2025		788446	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$5.25	\$5.25	\$0.00	6
8/15/2025		788183	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$4.15	\$4.20	\$0.05	5
8/19/2025		788836	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.35	\$3.35	\$0.00	4
8/20/2025		789087	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.20	\$3.30	\$0.10	4
8/21/2025		789374	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.30	\$3.35	\$0.05	4
8/22/2025		789909	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.30	\$3.35	\$0.05	5
8/23/2025		789911	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.10	\$3.10	\$0.00	5
8/26/2025		790258	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.90	\$2.95	\$0.05	4
8/27/2025		790512	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.80	\$2.90	\$0.10	5
9/16/2025		794473	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.10	\$0.10	6
9/17/2025		794483	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.35	\$0.10	5
9/18/2025		794714	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.35	\$3.35	\$0.00	6
9/19/2025		795274	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.15	\$3.15	\$0.00	6
9/20/2025		795281	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.00	\$3.00	\$0.00	6
9/25/2025		796286	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.20	\$3.20	\$0.00	4
9/26/2025		796654	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.35	\$3.67	\$0.32	6
10/1/2025		797557	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.30	\$0.05	4
10/3/2025		798171	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$3.25	\$3.25	\$0.05	5
10/18/2025		801154	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.70	\$0.05	4
11/20/2025		808567	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.20	\$6.25	\$0.05	4
11/25/2025		809725	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$6.00	\$6.10	\$0.10	3
11/26/2025		810121	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$9.00	\$9.00	\$0.00	2
12/23/2025		817151	NG Next Day	BAILEYVILLE	Emera Energy L.P.	\$10.40	\$10.45	\$0.05	2

Figure VIII-18: Intra Day Trades delivered to Baileyville

Trade Date	Trade ID	Trade Class	Point	Counterparty	Natural Gas Price	Daily Maximum Price	Daily Maximum Price Less Emera NG Price	Number of Trades on same day	Summary of Gas Traders' Bid Notes
1/3/2024	596297	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$5.00	\$5.00	\$0.00	2	
2/7/2024	604244	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$3.75	\$4.31	\$0.56	2	
2/16/2024	606290	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$3.50	\$3.50	\$0.00	1	
2/19/2024	606366	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$4.45	\$4.73	\$0.28	2	
5/7/2024	622591	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$1.95	\$1.95	\$0.00	1	
6/27/2024	634637	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$2.30	\$2.30	\$0.00	1	
7/25/2024	704871	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$2.60	\$2.66	\$0.06	2	
10/3/2024	719958	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$2.65	\$2.65	\$0.00	2	
11/7/2024	727210	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$1.90	\$1.95	\$0.05	2	
1/18/2025	742266	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$15.50	\$15.50	\$0.00	3	
2/24/2025	751065	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$6.00	\$7.00	\$1.00	3	
6/19/2025	774922	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$4.40	\$4.40	\$0.00	1	
8/1/2025	786245	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$4.50	\$4.50	\$0.00	2	
8/5/2025	786261	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$4.75	\$4.75	\$0.00	2	
8/11/2025	787809	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$7.50	\$7.50	\$0.00	2	
8/29/2025	791337	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$2.80	\$2.85	\$0.05	2	
9/3/2025	792188	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$3.10	\$3.10	\$0.00	2	
11/19/2025	808582	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$6.65	\$6.75	\$0.10	3	
11/20/2025	808936	NG Intra Day	BAILEYVILLE	Emera Energy L.P.	\$7.15	\$7.15	\$0.00	1	

IX. Oil Procurement and Management

IX.A. Background

Fuel oil is typically a small portion of NSPI's FAM costs and fuel purchases. This chapter addresses NSPI's procurement and management of Heavy Fuel Oil ("HFO") and Light Fuel Oils ("LFO"), which include diesel and furnace oil. HFO is a byproduct of crude oil refining. It is a viscous oil and must be kept heated during periods of use. It is often referred to as a residual oil by its grade number and sulfur content (e.g., #6, 2.0%). HFO is used by NSPI primarily at Tufts Cove, where it can be burned in units 1, 2, and 3 instead of natural gas. The ability to switch between HFO and natural gas provides NSPI with an option to burn the lower cost fuel and a physical backup should natural gas be unavailable. HFO is also burned to co-fire some of NSPI's coal units or when starting the units. LFO is a mid-weight petroleum product that includes diesel fuel, kerosene, and furnace oil. In some applications, these products can be used interchangeably. LFO is used by NSPI for various purposes. Furnace oil is used for start-up and shut-down of fuel-milling systems and main boilers at its solid fuel-fired generators. Diesel is used to fire NSPI's seven diesel-fired combustion turbines (Burnside, Victoria Junction, and Tusket units) and for vehicle fuel.

IX.B. Findings

During the Audit Period, NSPI purchased [REDACTED] cargoes of HFO³⁶⁴, [REDACTED] of which came after an approved standing order for permission to purchase an additional cargo of HFO if required for the 2025/2026 winter period. LFO was purchased periodically, as needed, throughout the Audit Period pursuant to [REDACTED] existing contracts with [REDACTED].³⁶⁵

The details of these findings are below.

IX.B.1. Heavy Fuel Oil (HFO) Findings

NSPI can burn HFO at its solid fuel plants and at Tufts Cove units 2 and 3, with the majority of the storage and usage at Tufts Cove; HFO can no longer be burned at Tufts Cove unit 1. HFO is delivered by ocean-going tankers to Tufts Cove, and then re-delivered by truck to other generation plants, as needed. NSPI can store 457,492 barrels at Tufts Cove in one large tank and three smaller day tanks.³⁶⁶ Of this

³⁶⁴ [REDACTED].

³⁶⁵ Parkland - 20231230 First Amending Agreement 6521.9055.pdf; [REDACTED].pdf.

³⁶⁶ Fuel Manual Revision 14, Section 7.4.2 Fuel Oil.

quantity, approximately 9.6 percent, or 43,843 barrels, is storage “heel” and cannot be withdrawn.³⁶⁷ The effective maximum inventory is therefore 413,573 barrels ($457,492 \times (1 - 0.096) = 413,573$). The HFO is typically delivered to NSPI in quantities up to 275,000 barrels at a time.³⁶⁸

Based on the plant-level inventory data, NSPI purchased two cargoes of HFO and used [REDACTED] barrels for generation during the Audit Period at a cost of \$ [REDACTED]. NSPI used Aligne to track liquid inventories and associated costs, by generation plant. As noted in earlier chapters, on April 25, 2025, Aligne became unavailable due to the cyber event. The cyber event did not affect Aligne’s historical database (pre-April 25, 2025 data), which was housed on off-site servers. During the period when Aligne was unavailable, inventories and associated costs were tracked manually in Excel using information on purchase, transfer, and consumption volumes provided by plant superintendents on a monthly basis. Bates White used both data sets to summarize liquid fuel usage and costs and compare the results to the entries in the Q4 FAM filings.

The results for this audit were fairly close, differing in cost by \$ [REDACTED] (0.25 percent), but there was no difference in the number of barrels purchased. Figure IX-1 below summarizes the differences on an annual basis. NSPI explained that these variances result from year-end true ups and entries made to the General Ledger outside of Aligne. We reviewed NSPI’s reconciliation of HFO costs and found that such costs were properly accounted for.

Figure IX-1: Comparison of Adjusted HFO Costs from Aligne to Reported Q4 FAM Costs³⁷⁰

	2024		2025		Total	
	Barrels	Cost	Barrels	Cost	Barrels	Cost
Aligne	[REDACTED]					
Q4 FAM Report						
Difference						

The prior audit period saw the testing and inspection of the HFO tank at Lingan in spring/summer of 2023, after which HFO was trucked from both Tufts Cove and Point Tupper to the plant. Still, Lingan’s HFO inventory had fallen below preferred levels at the start of the current Audit Period (February 2024), resulting in HFO again being trucked from both Tufts Cove and Point Tupper to Lingan. In May 2024, NSPI also entered into a contract with incumbent [REDACTED] to truck HFO from Tufts Cove to Lingan, Point Tupper, and if required, Trenton.³⁷¹ The initial volumes requested for transport to Lingan

³⁶⁷ 2022-2023 Bates White Audit Report, page 199.

³⁶⁸ Fuel Manual Revision 13, Section 7.4.2 Fuel Oil.

³⁶⁹ Q4 FAM Reports.

³⁷⁰ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).

³⁷¹ This ROA also includes a request for permission to designate Seaboard as a “favored supplier.”

earlier in the year were approximately doubled in November 2024 to replace summer consumption and restore the tank to near the 30-foot level and thereby mitigating any potential constraints in winter.

The monthly HFO inventory levels are summarized in Figure IX-2. Subsequent figures illustrate the HFO inventory levels, by generation plant.

Figure IX-2: Summary of HFO Inventory Changes (December 2023-December 2025)



The HFO usage and inventory at Tufts Cove is shown in the following Figure IX-3.

Figure IX-3: Month-End HFO Inventory Changes at Tufts Cove (December 2023-December 2025)



The HFO inventory changes at the other three generating plants that burn HFO do not typically exhibit the volatility seen at Tufts Cove because HFO is a secondary fuel at these locations. Figure IX-4 shows the monthly HFO inventory levels at Lingan, Point Tupper, and Trenton 5 during the Audit Period.

Figure IX-4: Month-End HFO Inventory Changes at Lingan, Point Tupper, and Trenton 5 (December 2023–December 2025)



IX.B.1.a. Analysis of the HFO Transaction Decisions

NSPI purchased [REDACTED] pursuant to an RFP that was issued on November 12, 2024, and contracted on November 27, 2024. The RFP had no set limit on sulphur content of product, and included an option for an additional cargo. [REDACTED] counterparties—[REDACTED]—submitted responses, both offering cargo options at 1% and 0.7% sulphur ([REDACTED]). NSPI modeled the various options in Plexos and found that despite the emissions-related cost savings associated with the [REDACTED]% and [REDACTED]% sulphur content offers, the [REDACTED]% cargo options were more economic due to the high premium on lower-sulphur product. [REDACTED] content cargo bid was ultimately selected over [REDACTED] based on cost.

NSPI purchased a cargo of HFO from [REDACTED] pursuant to an RFP that was issued on January 22, 2025, and contracted on February 6, 2025. As with the previous RFP, this RFP also had no set limit on sulphur content of product. [REDACTED] counterparties submitted responses with cargo options including [REDACTED]%, [REDACTED]%, and [REDACTED]% sulphur content. Also like the previous RFP, NSPI concluded that potential emissions-related cost savings associated with the lower-sulphur content offers did not outweigh the cost savings attached to the actual delivered price with the [REDACTED]% sulphur content offers. [REDACTED] content cargo bid was ultimately selected over the other [REDACTED]% sulphur content offers on the basis of cost.

IX.B.1.b. Pre-Approval of HFO Cargo Purchase

On December 18, 2025, a recommendation for standing approval to purchase HFO was approved. With a Dec 2025-Feb 2026 price forecast of delivered gas being at or above HFO, materially higher natural gas prices versus HFO observed in December 2025, and (then) active dispatch of Tufts Cove units 2 and 3, the pre-approval to purchase a cargo of HFO during the period was granted. NSPI ultimately purchased one cargo of HFO from [REDACTED] on the approval date (December 18, 2025) itself³⁷² pursuant to an RFP that was issued on December 8, 2025.

IX.B.1.c. Light Fuel Oil (LFO)

NSPI used LFO as start-up fuel, motor vehicle fuel, and for other applications at its generation plants, and burned diesel fuel at its combustion turbine facilities, such as Burnside and Victoria Junction. In the Audit Period, LFO was supplied by [REDACTED]. The contracts had no minimum or maximum quantity provisions and had some overlap in capabilities.³⁷³ Pricing was tied to [REDACTED]³⁷⁴ and both parties used [REDACTED] for truck transport. NSPI did not renew or extend the [REDACTED] supply contract following the end of its term on December 31, 2024.

Across all its plants, NSPI burned [REDACTED] barrels of diesel fuel and [REDACTED] barrels of furnace oil.³⁷⁵ NSPI's diesel consumption was [REDACTED] percent less than the budgeted amount, while furnace oil consumption was [REDACTED] percent more than the budgeted amount. The following Figure IX-5 shows the monthly consumption, in barrels, for the Audit Period.

³⁷² Texas Aromatics - Texas Aromatics - 20251218 HFO Sales Agreement.pdf.

³⁷³ Parkland - 20231230 First Amending Agreement 6521.9055.pdf; Irving Oil Limited -20240101 Light Fuel Oil Agreement.pdf, Schedule A.

³⁷⁴ Parkland - 20210101 Parkland Corporation Light Fuel Oil Agreement.pdf, Section 5.1; Irving Oil Limited -20240101 Light Fuel Oil Agreement.pdf, Section 5.1.

³⁷⁵ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).

Figure IX-5: Summary of LFO Usage (Barrels), 2024-25



Based on the plant-level data from Aligné, NSPI used [REDACTED] barrels of LFO for the generation of electricity during the Audit Period at a cost of \$ [REDACTED]. While total LFO consumption as recorded in Aligné matched the data in the Q4 FAM Report, the same could not be said for the associated costs, which differed between the two by \$ [REDACTED]. This data is summarized in Figure IX-6 below. As with the HFO cost data, NSPI explained that the variance in LFO costs also results from year-end true ups and entries made to the General Ledger outside of Aligné. We reviewed NSPI's reconciliation of LFO costs and found that such costs were properly accounted for.

Figure IX-6: Summary of LFO Inventory Changes, 2024-25³⁷⁶

	2024		2025		Total	
	Barrels	Cost	Barrels	Cost	Barrels	Cost
	[REDACTED]					

³⁷⁶ Q4 2024 FAM Report, 3(3); Q4 2025 FAM Report, 3(3).

The figures below show the month-end inventory levels of LFO and diesel at various NSPI plants.

Figure IX-7: Month-end LFO inventory levels at Lingan, Point Aconi, Point Tupper, Trenton, and Tufts Cove (barrels), 2024-25



Figure IX-8: Month-end diesel inventory levels at Burnside, Tusket, and Victoria Junction (barrels), 2024-25



IX.B.2. Bates White's 2022-23 Recommendations

In the 2022-2023 FAM Audit, Bates White made no recommendations related to Oil Procurement and Management.

IX.C. Conclusions

Conclusion IX-1: NSPI's process for deciding to contract for and purchase HFO was well documented, along with the decision to purchase 1 percent sulphur HFO at a lower cost and still meet environmental constraints.

Conclusion IX-2: HFO price quotes included delivery by tanker, which required the supplier to bear the risk of chartering tankers, effect delivery of the HFO, and cover other potential losses occurring prior to delivery.

Conclusion IX-3: NSPI's contracts for HFO, LFO, and related services continued to contain important protections for NSPI and FAM customers (as required by the Fuel Manual), including required technical specifications of oil products, no minimum delivery quantities, and non-exclusive clauses that allowed NSPI to contract with other suppliers, if necessary. These contracts were reasonably extended.

Conclusion IX-4: The decision to extend the term of the LFO contracts for 2024 and 2025 was well reasoned and implemented on a timely basis. There was no effect on FAM customers during this Audit Period.

Conclusion IX-5: The HFO and LFO quantities summed from the plant level data match those in the FAM reports, the costs did not. In both cases, these differences amount to less than one percent of each fuel's total cost for the Audit Period. NSPI provided reconciliations showing that adjustments to costs were made outside of Aligner.

IX.D. Recommendations

None.

X. Power Plant Performance

X.A. Background

In this chapter, we look at the performance of NSPI's thermal generation fleet. NSPI's thermal fleet provides a substantial portion of NSPI's total system requirements—in 2024, the thermal fleet provided 6,309,911 MWh,³⁷⁷ or 55.7% of the total system requirement,³⁷⁸ while in 2025, it provided 6,520,644 MWh,³⁷⁹ or 56.8%.³⁸⁰ NSPI's renewables fleet provided another 932,274 MWh in 2024 and 855,113 MWh in 2025.³⁸¹ Thus, collectively, NSPI's owned generation provided 14,617,942 MWh of energy during the Audit Period, representing 64.1% of NSPI's total system requirement. Our purpose in this chapter is to examine the performance of NSPI's generation fleet over the Audit Period, as measured by standard industry metrics and benchmarks. We review NSPI's outage management process and provide details on outages observed during the Audit Period. We provide details about the costs involved in maintaining the generation fleet as it is currently constituted. We also provide evidence in the day-to-day operations of the fleet, gleaned from review of NSPI's records.

NSPI's thermal generation fleet consists of four coal-fired plants: the four-unit Lingan plant, totaling 607 MW; the two-unit Trenton Plant, totaling 304 MW; the lone 150 MW unit at Point Tupper; and the 168 MW unit at Point Aconi, which uses fluidized bed combustion to burn a solid fuel blend that is primarily petcoke, plus coal. NSPI's other solid fuel-fired plant is the 43 MW biomass facility at PHP. NSPI's fleet includes six units at the Tufts Cove plant. Tufts Cove 1, 2, and 3 are natural gas-fired steam turbines (with units 2 and 3 having the ability to fuel-switch to burn HFO) totaling 318 MW, while the remaining Tufts Cove units make up a 2x1 combined-cycle train, with Tufts Cove 4 and 5 being natural gas-fired gas turbines and Tufts Cove 6 being the heat-recovery steam turbine—together, the trains total 144 MW. Lastly, NSPI owns seven 33 MW LFO-fired jet engines: four at Burnside, two at Victoria Junction, and one at Tusket. Figure X-1 provides additional detail on NSPI's thermal fleet.

³⁷⁷ Q4 2024 FAM Report, 2(3).

³⁷⁸ Based on a total system requirement of 11,326,320 MWh. See NSPI's Q4 2024 FAM Report, 2(3).

³⁷⁹ Q4 2025 FAM Report, 2(3).

³⁸⁰ Based on a total system requirement of 11,473,610 MWh. See NSPI's Q4 2025 FAM Report, 2(3).

³⁸¹ Q4 2025 FAM Report, 2(3).

Figure X-1: NSPI's Thermal Generation Fleet³⁸²

Power Plant	Max Net Capacity	Primary Fuel	Secondary Fuel	In-Service Year
Trenton 5	150	Coal	Petcoke	1969
Trenton 6	154	Coal	Petcoke	1991
Lingan 1	153	Coal	Petcoke	1979
Lingan 2	148	Coal	Petcoke	1980
Lingan 3	153	Coal	Petcoke	1983
Lingan 4	153	Coal	Petcoke	1984
Point Aconi	168	Petcoke	Coal	1994
Point Tupper	150	Coal	Petcoke	1973
Tufts Cove 1	78	Natural Gas	-	1965
Tufts Cove 2	93	Natural Gas	Heavy Fuel Oil	1972
Tufts Cove 3	147	Natural Gas	Heavy Fuel Oil	1976
Tufts Cove 4	49	Natural Gas	-	2003
Tufts Cove 5	49	Natural Gas	-	2005
Tufts Cove 6	46	Natural Gas	-	2012
Port Hawkesbury	43	Biomass	-	2013
Tusket 1	33	Light Fuel Oil	-	1971
Victoria Junction 1	33	Light Fuel Oil	-	1976
Victoria Junction 2	33	Light Fuel Oil	-	1975
Burnside 1	33	Light Fuel Oil	-	1976
Burnside 2	33	Light Fuel Oil	-	1976
Burnside 3	33	Light Fuel Oil	-	1976
Burnside 4	33	Light Fuel Oil	-	1976
Total	1,965			

In addition to the thermal fleet listed above, NSPI also owns hydro and wind resources, which total 375 MW and 81 MW of nameplate capacity, respectively. NSPI's ownership of wind farms historically qualified it for tax benefits in the form of accelerated capital cost allowances, which allows NSPI to minimize taxable income. For the Audit Period, NSPI stated that tax benefits related to its generation assets, such as tax credits and accumulated depreciation, do not flow through the FAM, but are generally accounted for as a reduction to current tax expense. Figure X-2 shows NSPI's wholly-owned hydro and wind fleet.

³⁸² 2025 Annual FAM Report A-2.

Figure X-2: NSPI's Wholly-owned Hydro, Wind Resources³⁸³

Power Plant	Nameplate Capacity (MW)	Generation Type
Annapolis	0	Hydro
Avon	7.4	Hydro
Black River	22.3	Hydro
Dickie Brook	3.8	Hydro
Fall River	0.5	Hydro
Lequille	11.2	Hydro
Mersey	42.5	Hydro
Nictaux	6.8	Hydro
Paradise	4.8	Hydro
Sheet Harbour	11.3	Hydro
Sissiboo	27	Hydro
St. Margaret's	10.4	Hydro
Tusket Hydro	2.2	Hydro
Wreck Cove	213.4	Hydro
Bear River	11.2	Hydro
Roseway/Harmony	0	Hydro
Nuttby Mountain	50.6	Wind
Digby Neck	30.0	Wind
Total	455.4	

³⁸³ NSPI also owns minority stakes in three wind farms at Sable Wind, South Canoe, and Point Tupper.

X.B. Findings

X.B.1. Refreshing our Contextual Analysis of NSPI's Thermal Generation Fleet

NSPI's generation mix includes a high – and growing – penetration of wind capacity coupled with a thermal fleet that is not optimal for addressing the operational challenges of a wind-heavy resource portfolio. The additional wind generation in Nova Scotia displaces energy that would have been provided by other sources (such as NSPI's thermal generation fleet) and reduces emissions, but provides limited capacity, requiring much of that thermal generation to be maintained for reliability, which means maintenance costs and other “sustaining capital” are needed to keep those plants in operating condition.

NSPI's thermal generation fleet is also not optimally suited for the operational challenge of backing up such substantial levels of fluctuating wind generation. Wind-heavy systems are best paired with flexible power generators, such as natural gas-fired combined cycle, combustion turbines, natural gas-fired jet engines, and flexible hydroelectric resources, as well as energy storage. Much of NSPI's thermal fleet is inflexible generation fired by solid fuel. This is shown in Figure X-3 below; specifically, NSPI's thermal units all have maximum ramp rates of 2.00 MW/minute or less—only the Tufts Cove Units 4, 5, and 6 have ramp rates higher than that. In practice, NSPI's thermal units are typically ramped at 1 MW/minute or less.³⁸⁴ For reference, modern, gas-fired, combined cycle generators have average ramp rates of 15–25 MW/minute³⁸⁵ or more.³⁸⁶

³⁸⁴ 2022-2023 Bates White Audit Report, page 210.

³⁸⁵ Steven Macmillan, Alexander Antonyuk, and Hannah Schwind, “Gas to Coal Competition in the U.S. Power Sector” (International Energy Agency Insights Series 2013), 14, available at <https://www.osti.gov/etdeweb/biblio/22112400>.

³⁸⁶ Miguel Angel Gonzalez-Salazar, et al., “Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables,” *Electricity Journal*, 82, Part 1, February 2018 (“*Electricity Journal* Article”), Table 2, available at <https://www.sciencedirect.com/science/article/pii/S1364032117309206#bib2>. See also GE Power, “LM6000 Power Plants,” available at https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2018-prod-specs/LM6000-power-plants.pdf.

Figure X-3: Maximum Ramp Rates of NSPI's Thermal Generating Units³⁸⁷

Thermal Plant	Ramp Rate (MW/Minute)
Lingan 1	2.00
Lingan 2	2.00
Lingan 3	2.00
Lingan 4	2.00
Point Aconi	1.00
Point Tupper	2.00
Trenton 5	1.75
Trenton 6	2.00
Tufts Cove 1	1.00
Tufts Cove 2	2.00
Tufts Cove 3	2.00
Tufts Cove 4	5.00
Tufts Cove 5	5.00
Tufts Cove 6	3.50
Port Hawkesbury	1.00

The impact of high wind penetration and displacement of energy output on NSPI's thermal generating fleet is demonstrated through reduced capacity factors, which we show and discuss below. However, the impact of wind on NSPI's thermal fleet also manifests itself in not just lower capacity factors but also a different approach to operating these units. Specifically, these units must be “cycled”—that is, turned “on” and “off” more frequently, ramped up and down more often, and ramped faster—rather than run as baseload facilities, as they were originally designed to do. Besides the impact on capacity factors, this approach can have negative impacts on the thermal plants themselves, including increased fatigue on plant components, higher capital and operational costs, increased forced outage rates, and reduced plant life.³⁸⁸ It can also lead to poorer emissions performance over time.³⁸⁹

Moreover, as we noted in prior audit reports, this has led to NSPI's thermal generation fleet being used to provide less energy and more operating reserves than it did prior to increases in wind penetration in Nova Scotia. This can primarily be seen through reduced capacity factors for the thermal units. As we explain in the next section, we continued to observe lower capacity factors for NSPI's thermal generation fleet, as well as high amounts of operating reserve. We address this and other unit performance metrics in the next section.

³⁸⁷ NSPI Response to 2-66 Attachment 10.

³⁸⁸ *Electricity Journal* Article.

³⁸⁹ *Electricity Journal* Article.

X.B.2. Analysis of Unit Performance

We reviewed each of NSPI's thermal generating units across a variety of industry standard metrics used to judge unit performance. The five metrics we examined were Capacity Factor ("CF"), Availability Factor ("AF"), outage and de-rate data, de-rated adjusted forced outage rate ("DAFOR"), and Heat Rate. We compare NSPI's generating units' performance against an industry-standard benchmark—typically "GADS"³⁹⁰ data from NERC across all generating units in North America that report their generating data. Moreover, in each case, we compare NSPI's individual unit performance against the applicable technology and unit size. We address each in turn below.

X.B.2.a.i. Capacity Factor

Figure X-4 provides the capacity factors for each thermal unit over the two years of the Audit Period, as well as the capacity factors of the diesel-fired combustion turbines and NSPI-owned renewable resources. Capacity factor measures the amount of actual output from a generator compared to its maximum potential output during a given period.

³⁹⁰ GADS stands for the Generator Availability Database System. The GADS database maintains operating histories on more than 7,700 generating units in North America. GADS is a mandatory industry program for conventional generating units that are 20 MW or larger. See: [https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-\(GADS\).aspx](https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx).

Figure X-4: Net Capacity Factors, NSPI Generating Units³⁹¹

Thermal Plant	2024 Capacity Factor	2025 Capacity Factor
Trenton 5	21.03%	29.22%
Trenton 6	43.14%	55.10%
Point Tupper	42.85%	52.54%
Tufts Cove 1	60.36%	18.85%
Tufts Cove 2	49.32%	41.24%
Tufts Cove 3	62.14%	39.92%
Tufts Cove 4	64.07%	60.00%
Tufts Cove 5	67.64%	56.09%
Tufts Cove 6	47.04%	38.42%
Lingan 1	37.44%	51.67%
Lingan 2	12.55%	19.43%
Lingan 3	38.72%	48.08%
Lingan 4	28.05%	45.27%
PH Biomass	43.08%	48.93%
Point Aconi	53.17%	45.58%
Total Thermal (ex-CTs)	41.44%	42.79%
Burnside 1	1.40%	1.80%
Burnside 2	1.33%	1.39%
Burnside 3	1.11%	1.32%
Burnside 4	0.71%	0.93%
Victoria Junction 1	0.26%	0.46%
Victoria Junction 2	0.40%	0.42%
Tusket 1	0.02%	0.68%
Hydro System	20.94%	18.15%
NSPI Wind	34.58%	36.65%
Total	34.16%	34.79%

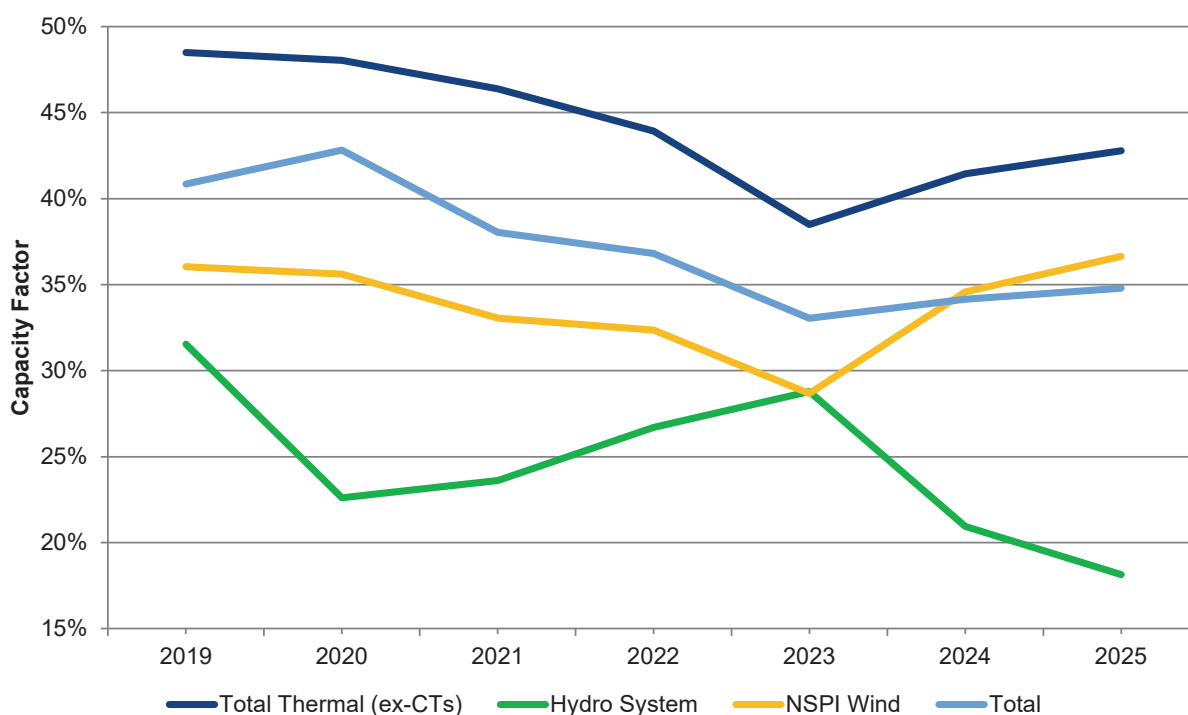
Figure X-4 confirms the recent trend of lower capacity factors across the thermal fleet. Most thermal units observed annual capacity factors below 50%. Contrast these results with those observed in 2007, prior to the arrival of significant wind generation resources in Nova Scotia, when NSPI's coal-fired generating fleet had a combined capacity factor of almost 90%.³⁹² Figure X-4 also shows results that differ between 2024 and 2025: coal-fired generators (Trenton, Lingan, Point Tupper) had significantly higher capacity factors in 2025 (relative to 2024), while the opposite was true for the natural gas-fired generators at Tufts Cove. This is largely the result of NSPI's receipt of the sulfur emissions compliance CoV in March 2025, which allowed for greater sulfur emissions (and thus more output from solid fuel-fired generation, relative to gas).

³⁹¹ 2024 FAM Annual Report A-2; 2025 FAM Annual Report A-2.

³⁹² 2014-2015 Liberty FAM Audit Report, page VIII-12.

Figure X-5 compares Audit Period capacity factors across the thermal units, renewable units, and total fleet to recent historical data. Thermal capacity factors (not including the diesel combustion turbines) rebounded in the Audit Period after reaching a four-year low in 2023. Capacity factors for wind also increased after steady declines 2019-2023. Hydroelectric capacity factors were low, falling to a new six-year low in 2025 of just over 18%. In fact, hydroelectric output for the Audit Period was 25% and 35% below the fleet's 23-year historical average in 2024 and 2025, respectively. NSPI indicated that the reason for this underproduction by the hydro fleet is weather patterns driven by climate change, as well as impacts from outages at Wreck Cove caused by life extension activities (explained later in this chapter). We noted that total precipitation during the Audit Period as measured at Halifax (Shearwater) was 2,186 mm, a reduction of 28.3% from precipitation in the 2022-2023 audit period (3,049 mm).³⁹³

Figure X-5: Total Annual Capacity Factors, by Generation Technology (2019-2025)³⁹⁴



Loading levels on the units further confirms these data. Figure X-6 shows the average loading on the thermal units observed during the Audit Period. Average load is determined by dividing the unit's total output, in MWh, by the number of operating hours. Importantly, average load removes the effect of “zero” MWh output hours and provides a useful metric: that is, when the unit is called upon, average load

³⁹³ Canada Weather Stats, “Total Precipitation – Annual data for Halifax (Shearwater),” available at: <https://halifax.weatherstats.ca/charts/precipitation-yearly.html>.

³⁹⁴ 2022-2023 Bates White Audit Report, page 213; 2024 FAM Annual Report A-2; 2025 FAM Annual Report A-2.

is the amount of energy it actually provides. As is shown, in most cases, the average load is well below the maximum net capacity of unit.

Figure X-6: Thermal Units' Average Load (MW)³⁹⁵

Thermal Plant	Max Net Capacity	Average Load 2024 (MW)	Average Load 2025 (MW)
Lingan 1	153	86	106
Lingan 2	153	76	46
Lingan 3	148	84	104
Lingan 4	153	82	94
Tufts Cove 1	78	68	34
Tufts Cove 2	93	73	56
Tufts Cove 3	147	111	84
Tufts Cove 4	49	36	39
Tufts Cove 5	49	37	34
Tufts Cove 6	46	27	28
Trenton 5	150	90	63
Trenton 6	154	96	102
Point Tupper	150	97	93
Point Aconi	168	118	94
Point Hawkesbury Biomass	43	25	24
Tusket	33	2	11
Victoria Junction 1 & 2	66	19	1
Burnside 1, 2, 3, & 4	132	20	15

A further look at the low loading levels of the thermal units can be examined by reviewing actual output data to determine how often units were being dispatched at their “economic minimum” operating level, which is the minimum megawatt amount of electric energy available from a generating resource for economic dispatch.³⁹⁶ Economic minimums vary by unit. Figure X-7 shows the economic minimum dispatch level for each of NSPI’s thermal generators fired by non-biomass solid fuel and provides the percentage of hours those units were dispatched at or below economic minimum. These units are instructive, as they are typically and historically baseload units that would rarely be operated at economic minimum or below.³⁹⁷

³⁹⁵ Q4 2024 FAM Report, 11(3); Q4 2025 FAM Report, 11(3); Data for Victoria Junction (two units) and Burnside (four units) is aggregated. In tab 11(3) in the Q4 2025 FAM Report, average load (annual) is misreported as a sum. The values in the 'Average Load 2025 (MW)' column are divided by twelve to account for this error.

³⁹⁶ See, e.g., ISO New England’s FAQs on Generator Operational Parameters, available at <https://www.iso-ne.com/participate/support/faq/generator-operational-parameters>.

³⁹⁷ 2014-2015 Liberty FAM Audit Report, page VIII-12.

Figure X-7: Percentage of Hours NSPI's Thermal Units Operated at Economic Minimum (or Lower) During Audit Period³⁹⁸

Thermal Plant	Economic Minimum (MW)	% of Hours Operating at Eco Min or Below
Lingan 1	60	37.3%
Lingan 2	60	82.3%
Lingan 3	60	39.0%
Lingan 4	60	48.6%
Point Aconi	115	59.1%
Point Tupper	65	32.2%
Trenton 5	65	67.5%
Trenton 6	70	45.8%

The implication of the previous three tables is that NSPI's thermal generators continue to provide less energy than they did before the introduction of significant wind generation in Nova Scotia. To further underscore this point, we again reviewed data on operating reserves. NSPI must carry operating reserves consistent with the requirements of the Northeast Power Coordinating Council ("NPCC"), NSPI's regional reliability authority.³⁹⁹ NSPI carries three operating reserve products in every hour of every day to help meet these requirements. Those three products are 30-Minute Reserve,⁴⁰⁰ 10-Minute Reserve,⁴⁰¹ and Synchronized Reserve.⁴⁰² NSPI also carries regulating reserves.⁴⁰³ These combined operating reserves are meant to ensure reliable operation in the event of unexpected generation or transmission problems that require additional generation to start producing energy in a short period of time. As is shown in Figure X-8, NSPI again enjoyed surpluses of operating reserves during the portion of the Audit Period for which NSPI had recoverable data. NSPI explained that due to the cyber event, it did not have operating reserve data for January 1, 2024 through April 24, 2025.

Figure X-8: NSPI's Average Operating Reserve Surpluses

Reserve Type	Requirement (MW)	2024 Average (MW)	2025 Average (MW)	Average Excess (MW)	Average Excess (%)
30-Minute Reserve	50	Data unrecoverable (cyber event)	387	337	674%
10-Minute Reserve	168		361	193	115%

³⁹⁸ Figure X-7 uses net generation due to the unavailability of gross generation data for most of the Audit period due to the impact of the cyber event.

³⁹⁹ NSPI must carry enough 10-minute reserve to cover its largest single contingency and enough 30-minute reserve to at least equal half of its second largest contingency.

⁴⁰⁰ NSPI carries at least 50 MW of 30-Minute Reserve.

⁴⁰¹ NSPI carries at least 168 MW of 10-Minute Reserve, based on Point Aconi's net plant rating (as Point Aconi is NSPI's single largest contingency).

⁴⁰² NSPI carries 32 MW of Synchronized Reserve.

⁴⁰³ NSPI carries at least 16 MW of both regulation up and regulation down service.

We have discussed operating reserves in detail in prior audit reports and note that NSPI has continued its evergreen IRP process in response to an earlier audit report and a directive from the Board, which remains the proper forum to consider NSPI's resource portfolio. Moreover, the long-term planning and procurement function for Nova Scotia has been transitioned to the IESO as of December 2025. Thus, we make no further recommendations regarding these observed operating reserve surpluses here, other than to note that they remained in place during this Audit Period.

X.B.2.a.ii. Availability Factor

The second metric we examined was Availability Factor, which NERC defines as the percentage of hours a unit is available over all potential hours of a given period.⁴⁰⁴ The higher the Availability Factor, the more available the unit was to generate electricity. Figure X-9 shows the Availability Factor for each of NSPI's thermal units for both 2024 and 2025, as well as the industry average for each unit's respective technology type and size. For example, each Lingan unit is a coal-fired, 153 MW unit. Thus, the appropriate comparison for these units is to coal-fired units between 100 and 199 MW. Green boxes illustrate instances where NSPI's performance beat the industry average; red indicates the opposite.

Figure X-9 shows that the fleet largely enjoyed Availability Factors that exceeded industry averages, especially at Lingan 1, Lingan 3, Point Tupper, Trenton 6, Tufts Cove 3, Tufts Cove 4-6, and PHB. Point Aconi and Trenton 5 were notable exceptions, lagging industry averages in both 2024 and 2025, driven in part by planned outages for generator and turbine work. Trenton 5's seasonal layup also impacted its availability.

⁴⁰⁴ NERC, "Appendix F – Performance Indexes and Equations."

Figure X-9: Availability Factors of NSPI Thermal Generating Units (Compared to Industry Averages)⁴⁰⁵

Thermal Plant	Availability Factor (2024)	Availability Factor (2025)	GADS Standard
Lingan 1	81.1%	89.5%	79.9%
Lingan 2	94.3%	73.3%	79.9%
Lingan 3	80.8%	89.2%	79.9%
Lingan 4	79.2%	86.4%	79.9%
Point Aconi	75.7%	69.2%	79.9%
Point Tupper	80.0%	80.6%	79.9%
Trenton 5	53.2%	51.2%	79.9%
Trenton 6	84.8%	82.5%	79.9%
Tufts Cove 1	81.7%	64.9%	68.0%
Tufts Cove 2	65.7%	77.6%	68.0%
Tufts Cove 3	82.9%	75.4%	74.0%
Tufts Cove 4	89.9%	87.0%	86.8%
Tufts Cove 5	91.1%	86.2%	86.8%
Tufts Cove 6	88.3%	90.0%	86.8%
Port Hawkesbury	84.1%	87.2%	73.8%

X.B.2.a.iii. Outages, De-Rates

Figure X-10 contains a summary of all outages by hour across all units in the Audit Period.

Figure X-10: Outage Hours of NSPI Thermal Generating Units (by Outage Category)

Thermal Plant	Planned	Maintenance	Forced	Total
Lingan 1	1,756	244	584	2,583
Lingan 2	2,808	0	37	2,845
Lingan 3	2,167	254	215	2,636
Lingan 4	2,388	559	78	3,025
Point Aconi	3,615	352	860	4,827
Point Tupper	2,198	523	737	3,458
Trenton 5	5,254	288	2,846	8,387
Trenton 6	1,837	584	359	2,780
Tufts Cove 1	2,486	1,544	650	4,680
Tufts Cove 2	3,711	1,049	212	4,973
Tufts Cove 3	2,708	540	407	3,655
Tufts Cove 4	1,561	176	291	2,028
Tufts Cove 5	1,294	139	530	1,963
Tufts Cove 6	1,615	254	37	1,906
Port Hawkesbury	1,658	278	579	2,514
Total	37,056	6,784	8,421	52,260

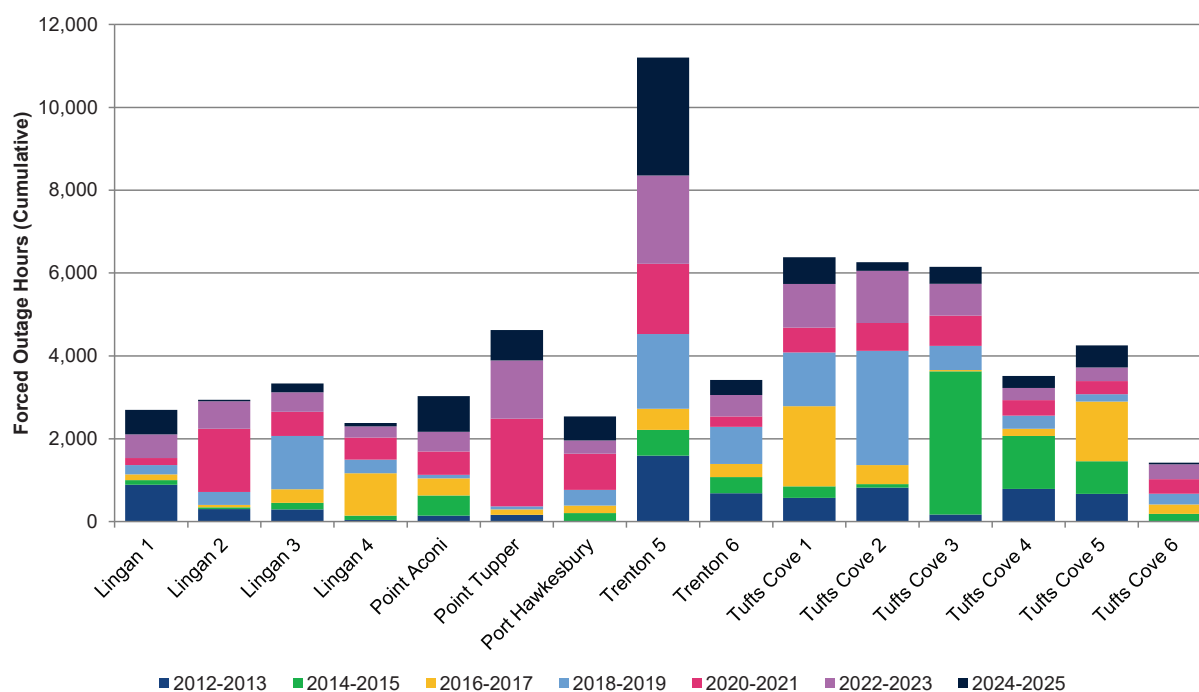
⁴⁰⁵ NERC's GADS does not have a category for biomass plants. Thus, we compared the biomass unit to "All Plants" between 1 and 99 MW. For Tufts Cove units 1, 2, and 3, we used Gas Primary as the comparative technology. For Tufts Cove units 4, 5, and 6, we used Combined Cycle Block as the comparative technology.

Fleetwide, total outage hours (52,260) increased by approximately 3.0 percent from the previous Audit Period.⁴⁰⁶ Planned outage hours (37,056) increased by 13.4 percent from the previous Audit Period's total of 32,671 hours.⁴⁰⁷ Forced outage hours (8,421) decreased by 22.7 percent from the previous Audit Period's total of 10,893 hours.⁴⁰⁸ Maintenance outage hours in this Audit Period (6,784) also decreased by approximately 5.7 percent compared to the last Audit Period's total of 7,193 hours.⁴⁰⁹

Notably, NSPI scheduled almost all planned outages outside of the winter peaking months.⁴¹⁰ This remains sound outage planning strategy, as it (1) avoids shutting down resources during the peak months of the year and (2) allows for extension of planned outages, when necessary and when economic to do so, as outages taken during lower-cost shoulder months reduce the opportunity cost of taking resources offline for planned maintenance.

A unit-by-unit comparison for this Audit Period's results with those in the past several Audit Periods is shown below in Figure X-11.

Figure X-11: Forced Outage Hours, by Unit, since 2012⁴¹¹



⁴⁰⁶ 2022-2023 Bates White Audit Report, Figure X-10.

⁴⁰⁷ 2022-2023 Bates White Audit Report, Figure X-10.

⁴⁰⁸ 2022-2023 Bates White Audit Report, Figure X-10.

⁴⁰⁹ 2022-2023 Bates White Audit Report, Figure X-10.

⁴¹⁰ See FAM Annual Reports, A6 (4c).

⁴¹¹ 2022-2023 Bates White Audit Report, Figure X-11.

During this Audit Period, NSPI did not materially alter its existing outage management procedures. NSPI uses an integrated outage coordination program to coordinate planned outages. NSPI maintains a “Planned Outage Request Process” containing detailed instructions and responsibilities. NSPI generates annual maintenance schedules in October for the following year, with planned outages being scheduled for non-winter months. Exceptions during the Audit Period included life extension activities at Wreck Cove, plus outages at several hydro resources that were scheduled through the end of December 2025. NSPI holds weekly meetings to review upcoming planned work on both generation and transmission elements. NSPI seeks to optimize the scheduling of outages, both in terms of outage time and labour cost. The Nova Scotia Power System Operator reviews, coordinates, and approves/rejects all outage requests. The protocols for outage coordination are memorialized in a single document, and contain clear delineations of responsibilities, directions for scheduling outages, and protocols for the grouping, prioritizing, and classification of outages.⁴¹² Regarding forced outages, NSPI conducts root cause analyses, including assessing any equipment-related issues that could apply to other units. Once complete, results of the root cause analysis are communicated so that other units can benefit from those results. We discuss specific forced outages and root cause analyses from the Audit Period later in this chapter.

In addition to outages, we also looked at incidents where NSPI thermal units were de-rated during the Audit Period, i.e., when conditions at the plant limited the total potential output of the unit to be something less than the unit’s full capacity. In total, NSPI’s thermal fleet⁴¹³ saw 900 de-rates during the Audit Period, which is down 19 percent from 1,111 derates in the prior Audit Period. The average de-rate was approximately 68 MW and lasted 128 hours.⁴¹⁴ Thus, while the number of derates decreased during the Audit Period, the size of the average derate increased by 8 MW (or 11.8%), as did the average duration of the derates (by 59 hours, or by 88.2%).

Aggregating de-rate and forced outage data is best done and judged using standard metrics. In this case, DAFOR serves this purpose; we address DAFOR in the next subsection.

X.B.2.a.iv. DAFOR

The third performance metric we examine is the DAFOR. DAFOR represents the percentage of time that a unit was in forced outage. DAFOR includes both forced outage hours as well as adjusted de-rated hours; it does not include planned outage hours or hours in which the unit is shut down for economic reasons. DAFOR is a measure used in Canada; its NERC-equivalent is the Equivalent Forced Outage Rate (“EFOR”) metric,⁴¹⁵ which we use as a reasonable proxy for comparison purposes. The lower the DAFOR, the less time that unit spent on forced outage or in de-rated status.

⁴¹² Nova Scotia Power System Operator, Market Procedure MP-09, Outage Planning and Approval, Issue 01.2.

⁴¹³ This includes the units at Lingan, Trenton, Point Aconi, Point Tupper, Port Hawkesbury, and Tufts Cove.

⁴¹⁴ Calculated from data provided in FAM Annual Reports, A6 (4c). Our data presented here includes all entries provided by NSPI in A6 (4c), some of which derate the unit to 0 MW.

⁴¹⁵ NERC, “Appendix F – Performance Indexes and Equations.”

Figure X-12 below shows NSPI's thermal fleet's DAFOR versus industry averages; green highlights denote performance that is better than industry average; red indicates the opposite.

Figure X-12: NSPI's DAFOR, by Unit, by Year, Compared to GADS EFOR Standard⁴¹⁶

Thermal Plant	DAFOR (2024)	DAFOR (2025)	GADS EFOR Standard
Lingan 1	5.2%	5.8%	11.5%
Lingan 2	2.6%	1.2%	11.5%
Lingan 3	0.1%	3.2%	11.5%
Lingan 4	0.6%	1.8%	11.5%
Point Aconi	11.1%	1.2%	11.5%
Point Tupper	11.9%	2.9%	11.5%
Trenton 5	14.0%	14.4%	11.5%
Trenton 6	7.8%	2.9%	11.5%
Tufts Cove 1	5.6%	11.6%	50.1%
Tufts Cove 2	0.3%	4.0%	50.1%
Tufts Cove 3	4.1%	5.0%	20.0%
Tufts Cove 4	7.5%	5.8%	5.5%
Tufts Cove 5	2.2%	7.6%	5.5%
Tufts Cove 6	1.2%	2.7%	5.5%
Port Hawkesbury	6.7%	1.7%	26.3%

Overall, NSPI's thermal fleet performed better than industry average as measured by DAFOR. Trenton 5 and Tufts Cove 4 were the only units to underperform GADS averages in both 2024 and 2025.

In our prior audit, we identified a concern whereby NSPI reported certain forced outages as forced derates (with a “0 MW” capability).⁴¹⁷ There were close to 1,000 incidents of this in the prior audit period, and we noted that NERC's definition of a derate is “a **partial** outage with an associated reduction in capacity.”⁴¹⁸ We included a recommendation that NSPI address the identified discrepancy in reporting of forced outages and derates and revise its outage/derate tracking and reporting, as appropriate.⁴¹⁹ NSPI has responded to this recommendation by updating its FAM Annual Reports to better and more accurately identify its forced outages and forced derates.⁴²⁰

X.B.2.a.v. Heat Rate

The next performance metric we considered was Heat Rate, which is a measure of a generating unit's efficiency. It divides fuel burned (in MMBtu)—or energy “in”—by electricity produced (in kWh)—or

⁴¹⁶ For the Tufts Cove units 4, 5, and 6, we provide EFOR data for a combined-cycle unit.

⁴¹⁷ 2022-2023 Bates White Audit Report, section X.B.2.a.iv.

⁴¹⁸ NERC, “Derate Event Reporting – Data Reporting Instructions – Section III,” slide 3, available at: https://www.nerc.com/pa/RAPA/gads/Training/2022_Conventional_GADS_Training_Module_06_Derate_Event_Reporting.pdf. Emphasis added.

⁴¹⁹ 2022-2023 Bates White Audit Report, Recommendation X-1.

⁴²⁰ 2025 FAM Annual Report, tab A6 (4c).

energy “out.”⁴²¹ The lower the heat rate, the more efficient the generating unit. **Figure X-13** shows the Heat Rates for each of NSPI’s units. Note that NERC does not provide averages in GADS for heat rate.

Figure X-13: NSPI Thermal Unit Heat Rates (Btu/kWh)⁴²²

Thermal Plant	Heat Rate (2024)	Heat Rate (2025)
Lingan 1	11,775	11,382
Lingan 2	12,226	11,304
Lingan 3	11,360	11,059
Lingan 4	11,423	10,236
Tufts Cove 1	11,350	11,548
Tufts Cove 2	10,842	10,264
Tufts Cove 3	10,675	10,985
Tufts Cove 4-6	8,467	8,795
Point Tupper	11,265	10,275
Point Aconi	11,407	10,656
Trenton 5	11,124	10,109
Trenton 6	10,511	10,403

The US Energy Information Administration posts average heat rates for general fuel sources—i.e., “coal,” “natural gas,” etc.⁴²³ This is an imperfect proxy but can give some indication of the efficiency of the NSPI fleet. For coal, the average 2024 heat rate is 10,777 Btu/kWh. In 2024, only Trenton 6 beat the average; in 2025, just five of the eight units beat that average. (We note that 2025 EIA data is not yet available.) The more positive results in 2025 are caused in part by the higher capacity factors achieved by NSPI’s solid fuel-fired generators. Higher capacity factors and higher average loading are associated with more efficient production, and thus lower heat rates. For natural gas, the average unit had a heat rate of 7,754 Btu/kWh, well below the Tufts Cove units. This result is driven by the small size and vintages of the three steam units; as for the combined-cycle units, those offer the lowest heat rates, but still above sub-7,000 heat rates available in newer, larger combined-cycle plants.⁴²⁴

As part of NSPI’s overall fleet performance program, NSPI continues to focus on heat rates and employs a heat rate improvement program to detect and quantify heat rate deviations, diagnose causes of lagging heat rates, identify corrective actions, schedule and complete maintenance work, and track and confirm heat rate improvements. As part of this process, NSPI engages practices and employs numerous

⁴²¹ US Energy Information Administration, “What is the efficiency of different types of power plants?,” available at: <https://www.eia.gov/tools/faqs/faq.php?id=107&t=3>.

⁴²² 2024 FAM Annual Report A6 (2); 2025 FAM Annual Report A6 (2).

⁴²³ U.S. EIA, “Table 8.1. Average Operating Heat Rate for Selected Energy Sources, 2014 through 2024,” available at https://www.eia.gov/electricity/annual/html/epa_08_01.html.

⁴²⁴ See, for example, Panda Temple Power, a 758 MW gas-fired combined cycle power plant in Temple, Texas.

controls to ensure accuracy of measurements and diagnoses, such as daily verification of a unit's generation output and regular calibration of instrumentation.

X.B.2.a.vi. Utilization Factor

The last performance metric we reviewed was Utilization Factor (“UF”). NSPI focuses on UF for its plants as a metric that captures the “wear” on its generating units driven by capacity factors, cycling, operating hours, flexible use, or some combination of these.⁴²⁵ Contributors to high UFs include high capacity factors, frequent unit starts, and unit cycling (or some combination of these factors).

The figures below compare NSPI's forecasted UF for each of its generating units to the actual UF for each unit for both 2024 and 2025. Green highlights indicate that the actual UF equaled the most recent UF forecast for that unit; red indicates the opposite. In most cases, actual UFs did not match forecast, and in all such cases but one, actual UFs exceeded forecast UFs. Higher UFs can mean higher sustaining capital investments and O&M costs.⁴²⁶

Figure X-14: 2024 Utilization Factors (Actual vs. Forecast)⁴²⁷

Unit	Starts	Net Capacity Factor	Operating Hours	UF Actual	UF Forecast
Lingan 1	22	37%	5,098	High	Medium
Lingan 2	12	13%	2,155	Low	-
Lingan 3	19	39%	6,189	High	Medium
Lingan 4	25	28%	4,601	Medium	Medium
Point Aconi	7	53%	6,651	High	Low
Point Tupper	16	43%	5,829	High	Medium
Trenton 5	10	21%	3,078	Medium	Low
Trenton 6	24	43%	6,053	High	High
Tufts Cove 1	12	60%	6,109	High	Low
Tufts Cove 2	8	49%	5,496	High	Medium
Tufts Cove 3	9	62%	7,219	High	Medium
Tufts Cove 4	56	64%	7,696	High	High
Tufts Cove 5	24	68%	7,814	High	High
Tufts Cove 6	66	47%	6,945	High	High
Port Hawkesbury Biomass	44	43%	6,554	High	High

⁴²⁵ 2022-Evergreen-IRP-Updated-Assumptions-January-2023-Update.pdf, slide 42.

⁴²⁶ 2022-Evergreen-IRP-Updated-Assumptions-January-2023-Update.pdf, slide 42.

⁴²⁷ 2024 FAM Annual Report A2.

Figure X-15: 2025 Utilization Factors (Actual vs. Forecast)⁴²⁸

Unit	Starts	Net Capacity Factor	Operating Hours	UF Actual	UF Forecast
Lingan 1	20	52%	6,544	High	Medium
Lingan 2	5	19%	2,516	Medium	-
Lingan 3	22	48%	6,046	High	Medium
Lingan 4	23	45%	5,865	High	Medium
Point Aconi	8	46%	6,045	High	Ultra Low
Point Tupper	9	53%	6,672	High	High
Trenton 5	14	29%	3,916	Medium	Low
Trenton 6	9	55%	6,408	High	Medium
Tufts Cove 1	4	19%	2,248	Low	Ultra Low
Tufts Cove 2	27	41%	4,874	Medium	High
Tufts Cove 3	22	40%	5,788	High	High
Tufts Cove 4	68	60%	7,061	High	High
Tufts Cove 5	52	56%	6,952	High	High
Tufts Cove 6	63	38%	6,794	High	High
Port Hawkesbury Biomass	23	49%	7,527	High	High

X.B.3. Unit-Specific Issues Identified During Audit Period

This section provides findings across a number of generating units specific to their performance during the Audit Period. We begin with a general discussion of Root Cause Analyses documents.

X.B.3.a. A Note About Root Cause Analyses

This section includes discussion of several Root Cause Analyses, which were conducted by NSPI personnel (and occasionally supplemented by third-party experts/vendors). Root Cause Analyses explore the reasons why something has gone wrong and may contain details that are critical of NSPI and its employees. These documents are the product of careful review, investigation, and assessment by NSPI personnel of (typically) negative events that may incur incremental costs for customers (e.g., generating assets being taken offline). These are some of the most important documents produced by an electric utility, particularly those that own generating assets (like NSPI) because they permit identification of the drivers of negative events and opportunities for improvement in the future. We rely on these documents in the discussion below and, to be sure, these events must stand on their own. We do wish to note, however, that utilities do not commission such *ex post* studies of successful events, or days where the plant performed flawlessly, or what has worked well. We recommend considering these events within the context of NSPI's overall fleet performance, as explained in the preceding subsections of this chapter,

⁴²⁸ 2025 FAM Annual Report A2.

which shows the overall performance of the fleet and its constituent plants, in many cases outperforming peer generating stations (as measured by GADS data). We applaud NSPI for its continued use of Root Cause Analyses, which we found to be typically thorough and well explained, and underscore for the Board the importance of this process going forward.

Figure X-16 below shows all Root Cause Analyses that either (a) we received in our audit work of the current Audit Period or (b) remained in progress. We maintain our prior Audit Report's recommendation that NSPI provide Root Cause Analyses to future auditors as they are completed, even if it pertains to a prior Audit Period. We also note that each Root Cause Analysis contains one or more recommendation. While NSPI has addressed many of these recommendations already, 15 are in progress, and we provide a recommendation that NSPI should provide the Board an update on the status of any recommendations from the Root Cause Analyses that have yet to be fully addressed.

Figure X-16: Root Cause Analyses Received or in Progress

Generator	Status	Reviewed by Bates White?	Name
Port Hawkesbury	Complete	Yes	2024 BIO LP Extraction CV Rod Failure
Burnside	Complete	Yes	2024 BGT1 Blade Failure
Tufts Cove 2	Complete	Yes	2024 TUC2 Turbine Vibration and Balance Assessment
Burnside, Victoria Junction	Complete	Yes	2020 CT Performance Review
Tufts Cove 3	Complete	Yes	2020 TUC3 FWH-4 High DCA Temperature
Tufts Cove 3	Complete	Yes	2022 TUC3 Condenser Tube Condition Assessment
Tufts Cove 3	Complete	Yes	2023 TUC3 Generator Bearing Temperature Investigation
Point Tupper	Complete	Yes	2023 POT2 CW Pump Motor Performance Review
Point Tupper	Complete	Yes	2023 POT2 Hood Spray System and Airflow Assessment
Tufts Cove 2	Complete	Yes	2022 TUC2 Steam Line Integrity Assessment
Tufts Cove 4	Initiated	No	2024 TUC4 NOx Challenges
Burnside	Initiated	No	2025 BGT4 Intermediate Case Crack
Black River Hydro	Initiated	No	2025 Hollow Bridge Failed Stator Core
Tufts Cove 5	Initiated	No	2025 TUC5 Generator Bearing High Temperature

X.B.3.b. Tufts Cove

X.B.3.b.i. Fuel Switching Results

In a prior Audit Report, we concluded that Tufts Cove's dual-fuel units had numerous instances during the Audit Period of being limited in their ability to burn HFO.⁴²⁹ We concluded that limitations on the ability of the Tufts Cove dual-fuel units to burn HFO has negative impacts on FAM customers by sometimes requiring the Tufts Cove units to burn more expensive natural gas. In addition, because NSPI's

⁴²⁹ Tufts Cove units 1, 2, and 3 all have the ability to operate on either natural gas or oil. Moreover, these units can "switch" from burning natural gas to burning fuel oil – or vice versa – without taking the unit offline. NSPI claims that the process takes about two hours and requires the unit to reduce its output to effectuate the switch. The units can run at maximum capacity on either natural gas or fuel oil. NSPI has specific procedures for fuel switching that are codified in an operating procedure manual. Nova Scotia Power, "Tufts Cove Generating Station No. 2 Boiler Changing a Level from Firing Gas to Firing Oil," August 24, 2000.

fuel forecasting and hedging activities assume the Tufts Cove units can reliably switch, FAM customers may be less protected from high natural gas prices than implied by the modeling.

We reviewed the performance of the dual-fuel units during this Audit Period:

- Tufts Cove Unit 1 remains unable to fuel switch and is not expected to regain the ability to fuel switch during its remaining asset life. NSPI appropriately did not model the unit as being capable of fuel switching.
- Tufts Cove Unit 2 was able to fuel switch for the entire Audit Period and was modeled as such. The unit successfully switched fuels 22 times during the Audit Period and had no reported unsuccessful switches. All fuel switches occurred in winter months (December, January, February).
- Tufts Cove Unit 3 was available to switch for the entire Audit Period and was modeled accordingly. The unit successfully switched fuels 20 times during the Audit Period and had zero reported failures to switch. All fuel switches occurred during the winter period (as early as November 30 (2024) and as late as March 4 (2025)).

These fuel switches continue to have benefits for customers and it is a positive outcome to see successful switches occurring. We did note that other factors can limit fuel switching. For example, we observed that Tufts Cove 2 remained on HFO after January 22, 2024 through January 24, 2024 despite reductions in natural gas prices that made burning natural gas more economic than HFO. (Tufts Cove 3 switched to natural gas on January 23.) NSPI acknowledged that day-ahead natural gas prices for January 23, 2024 were economic but explained that it could not switch both Tufts Cove 2 and Tufts Cove 3 to burn natural gas due to insufficient natural gas pipeline pressure on the natural gas pipeline lateral it shares with Eastward Energy, the local gas distribution company. NSPI explained that in winter months during cold periods, Eastward Energy's demand increases, which means less pressure to serve NSPI's needs. NSPI does not track these instances due to their "rarity." Still, this can be a material limitation on NSPI's HFO-based hedge on natural gas prices.

X.B.3.b.ii. Performance Test Results at Units 2, 4, 5, and 6

During the Audit Period, NSPI conducted performance tests on unit 2 as well as the combined-cycle plant (units 4-6). The performance test for unit 2 tested its output capability and was tested pursuant to NERC Standard MOD-025-2 ("Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability").⁴³⁰ This was the first such test on Tufts Cove 2 since 2023. We address the results of this performance test in section X.B.8 below.

⁴³⁰ The NERC standard can be found here: <https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-025-2.pdf>.

In 2025, NSPI conducted the same maximum real power test (pursuant to NERC standard MOD-025-2) for units 4, 5, and 6. These were the first such tests on these units since 2022. Unit 4's gross and net real power results were [REDACTED] below current NPCC declared values. Unit 5's gross and net real power results were each [REDACTED] below current NPCC declared values. Unit 6 had similar results: its gross real power result was [REDACTED] below its current NPCC declared value, while its net real power was [REDACTED] below the current NPCC declared value.

X.B.3.b.iii. Start-up issues, resolutions at Tufts Cove 4, 5

There were twenty reported forced outages for failed starts at Tufts Cove Units 4 and 5 in 2025.⁴³¹ NSPI acknowledged this increase in failed startups, noting that the primary contributor was a recurring generator vent fan fault that affected both units. NSPI explained that detailed inspections were carried out to determine if operating limits had been exceeded (they had not) and led to the discovery of a failed motor as a contributing factor. Prior to the motor being replaced, NSPI endured the potential for failed startups to allow the units to remain available. Once the faulty motor was replaced, NSPI reported no further failed starts after July 31, 2025; in the remainder of 2025, the units started successfully 87 times without further recurrence.

X.B.3.b.iv. Failed oil pump supply system at Tufts Cove 5

From January 8, 2025 through January 13, 2025, Tufts Cove Unit 5 was forced offline due to a failed oil pump.⁴³² Specifically, the scavenge oil pump was unable to maintain required oil pressure, which was determined during inspection to have been caused by a partially obstructed inlet screen supplying the scavenge oil system. The pump itself was found to be mechanically serviceable, and following cleaning of the inlet screen, the unit was returned to service.

The pump supply inlet was estimated by NSPI to be original equipment installed at the time Tufts Cove 5 was commissioned in 2005. The oil pump system itself was inspected during a June 2024 unit overhaul by third-party firm [REDACTED], which confirmed it to be fit for continued service with no identified deficiencies. The original equipment manufacturer (General Electric) recommends overhauls to be done every 25,000 operating hours (including full overhaul of the oil pump) and inspections to be done annually. The overhaul and inspection were completed by [REDACTED] in June 2024, and the event occurred in January 2025, meaning the event was not caused by NSPI failing to meet inspection and overhaul guidelines of General Electric. NSPI stated that it had never seen this type of failure before, and as a result, has shortened the frequency of its preventive maintenance on the system to every six months. Given the impact of the failure of the oil pump system – i.e., a five-day, mid-winter forced outage – this is a reasonable step to take.

⁴³¹ 2025 FAM Annual Report, tab A6 (4b).

⁴³² 2025 FAM Annual Report, tab A6 (4b), row 86.

X.B.3.b.v. LM6000 engine efficiency impact on fuel costs

Tufts Cove units 4 and 5 operates three LM6000 engines, with two in place and a third spare that can rotate and replace the others. The three engines are identified as: (1) Engine 191-332, (2) Engine 191-443, and (3) Engine 191-253.⁴³³ Each LM6000 has an identical net nominal capacity (51.1 MW).⁴³⁴

Two Board Decisions associated with capital investment requests by NSPI associated with the LM6000 engines were referred to this audit. The first related to a March 7, 2024 “authorization to overspend” request associated with “CI C0041506 – LM6000 191-253 Major Engine Refurbishment Project.”⁴³⁵ The second related to an August 5, 2025 application by NSPI for Board approval of “CI C0068655 – LM6000 191-332 Life Extension and CI C0073491 – LM6000 191-443 Engine Replacement.”⁴³⁶ Both matters involved substantial capital expenditure requests and both decisions dealt with myriad issues and developed extensive evidentiary records. In both cases, the Board raised concerns about extended operation of the engines at net electrical efficiencies that were lower than their rated efficiencies, potentially resulting in unnecessary higher fuel costs for ratepayers.⁴³⁷

Our review suggests that actual, observed net average electrical efficiencies⁴³⁸ can differ in from OEM-certified efficiency ratings due to a variety of factors. These include ambient temperature, humidity, loading, fuel composition, water-injection availability, and how a unit is cycled. Because of these variables, actual net electrical efficiency values are not directly comparable to OEM-certified values. Consider, for example, the average net electrical efficiency of engine 191-253 in the years 2019-2022, as cited in the Board’s Decision in matter M12416.⁴³⁹ It is noted that engine 191-253 “was last refurbished in 2018 and put back into service in February 2019.”⁴⁴⁰ The engine’s actual net efficiency was 33.1% in 2019; however, in all subsequent years of the period, the unit’s efficiency *increased*, to 34.6% (2020), 34.2% (2021), and 34.4% (2022).⁴⁴¹ These data are inconsistent with the notion that a unit should perform most efficiently following a refurbishment. The distinct conditions faced in real world operations (relative to idealized test conditions) can drive these differences in efficiency metric outcomes.

Our review also suggests that GE’s certified 41% net electrical efficiency requires additional context. GE indicates that the engines at issue (all LM6000-PC SPRINT variants) have published ISO reference efficiency of approximately 39.7%. GE’s LM6000-PF SPRINT variants are certified to reflect a performance range of 14,250 kJ/kWh at 20% load to 9,068 kJ/kWh at 100% load, corresponding to a net

⁴³³ NSEB, Decision, M12416, April 16, 2026 (“April 2026 Decision”), paragraph 6.

⁴³⁴ April 2026 Decision, paragraph 6.

⁴³⁵ NSEB, Decision Letter, M11598, June 17, 2024 (“June 2024 Decision”), page 1.

⁴³⁶ April 2026 Decision, paragraph 1.

⁴³⁷ June 2024 Decision, page 4; April 2026 Decision, paragraph 48.

⁴³⁸ NSPI defines average net electrical efficiency as the ratio of net electrical energy produced to the total fuel energy input over a defined operating period, expressed as a percentage.

⁴³⁹ June 2024 Decision, page 4.

⁴⁴⁰ June 2024 Decision, pages 3 to 4.

⁴⁴¹ June 2024 Decision, page 4.

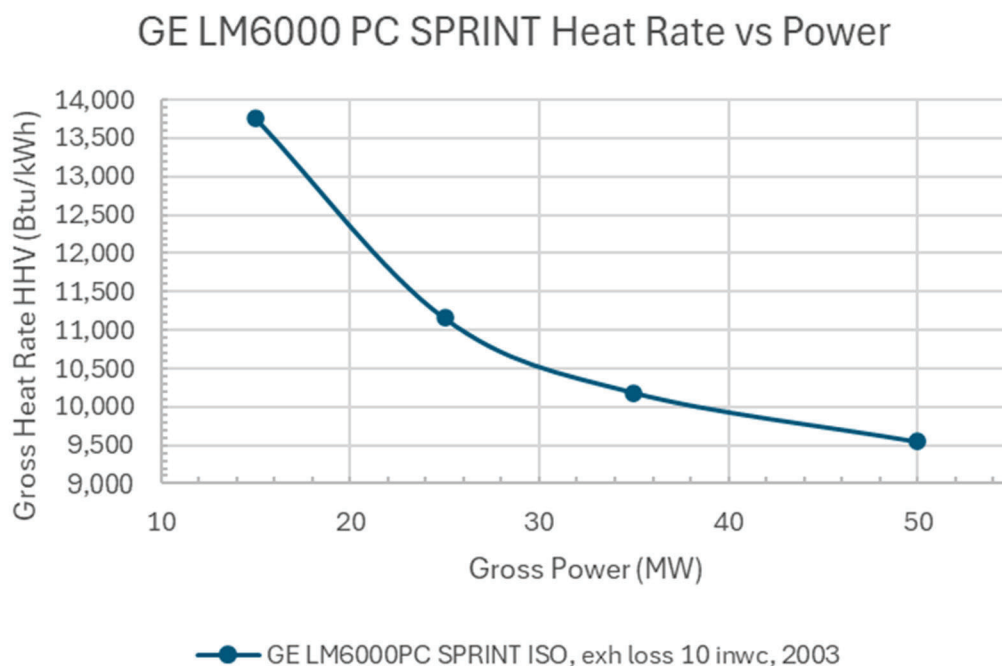
electrical efficiency of 36% to 41%. Moreover, GE's values assume single-engine, simple-cycle operation, while NSPI operates its LM6000s in parallel in a combined-cycle configuration, which results in different exhaust conditions and operating characteristics, and which also lead to lower efficiency.

To attempt to be more responsive to the Board's directives in the referenced decisions, we suggest that an effective way to assess the efficiency of an engine following a refurbishment is to conduct an ISO test upon recommissioning. That allows the variables we identify above to be controlled, and then to allow the results of that test to be compared to OEM specifications under those same (or similar) conditions. We requested evidence of any such tests from NSPI.

NSPI explained that it requested from the OEM (General Electric) a gross heat-rate versus gross power performance curve based on acceptance test data specifically for Engine 191-443. The OEM provided this curve, which adjusts for (1) ISO reference conditions, (2) typical heat recovery steam generator exhaust losses, and (3) NOx operating conditions. The corrected curve indicates a gross heat rate of approximately 8,600 Btu/kWh (LHV), equivalent to 9,546 Btu/kWh at full load (49.5 MW), corresponding to a gross thermal efficiency of 35.7% on an HHV basis. The figure below shows the OEM-provided expected gross heat rate performance curve (converted to HHV basis) used for comparison. The OEM curve is based on original acceptance test data for Engine 191-443 obtained in 2003, as updated for ISO ambient conditions, exhaust loss, and NOx operating condition.

Figure X-17: OEM-provided Adjusted Heat Rate Curve for NSPI's LM6000s

[The following graph is confidential.]



NSPI assessed the OEM-provided heat rate performance curve against performance at Tufts Cove Unit 4 for two separate engine swap periods. The next figure compares the gross load performance of Engine 191-443, in service from October 8, 2025 through October 16, 2025, to Engine 191-332, in service from October 27, 2025 through October 31, 2025, under similar fuel and ambient conditions. Specifically, the periods compared for these two resources had comparable average ambient temperatures and natural gas heating values; the intent was to compare engine performance during periods where external operating conditions were generally consistent and therefore would not materially influence observed differences in heat rate. The figure below allows for two comparisons: the engines' performance relative to GE's adjusted LM6000 heat rate curve, as well as a comparison of the two engines' performance relative to each other, with one (191-332) being installed following refurbishment and a second (191-443) at the end of an extended period of operation. The orange dots represent hourly average performance observations from Engine 191-443, while the yellow dots represent hourly average performance observations from Engine 191-332.

Figure X-18: October 2025 Performance of Engines 191-443, 191-332



The figure above shows that the performance of both engines tracks reasonably close to OEM adjusted heat rate specifications. The figure also shows that, as expected, the performance of the newly refurbished engine (191-332) slightly outperforms the engine that had been in extended operation (191-443). On average, engine 191-332 achieved a gross heat rate that was about 3-4% lower than engine 191-443.

The second period of comparison relates to a period in May-June 2022. The next figure compares the gross load performance of Engine 191-443, newly refurbished, against that of Engine 191-253, which was at the end of an extended period of service. The orange dots represent hourly average performance

observations from Engine 191-253, while the yellow dots represent hourly average performance observations from Engine 191-443.

Figure X-19: May/June 2022 Performance of Engines 191-253, 191-443



The figure above also shows that the performance of both engines tracks reasonably close to OEM adjusted heat rate specifications. The figure also shows that, as expected, the performance of the newly refurbished engine (191-443) moderately outperforms the engine that had been in extended operation (191-253). Given this data and our earlier discussion regarding net average electrical efficiency, we conclude that FAM customers did not face materially higher fuel costs due to unreasonably inefficient performance of the LM6000 engines.

X.B.3.b.vi. Root Cause Analysis Review

We were provided with and reviewed five Root Cause Analyses related to Tufts Cove units.

We reviewed NSPI's December 17, 2025 Root Cause Analysis associated with a June 15, 2023 unit trip of Tufts Cove 3 following a high temperature alarm for generator bearing 8. Tufts Cove 3's steam turbine comprises of a high pressure ("HP"), intermediate pressure ("IP"), and low pressure ("LP") turbines whose shafts are rigidly coupled together in line. The generator has eight principal bearings; bearing 8 is a spherically seated journal bearing carrying the brush gear end of the generator rotor and is lined with Babbitt material that provides a low friction, smooth surface lubricated with oil, which is monitored for temperature. Elevated temperature readings are a potential sign of bearing issues, which can occur as a result of damage or inadequate lubrication.

Beginning in August 2022, Tufts Cove 3's bearing 8 was observed to be running at an elevated temperature, and on June 15, 2023, the high temperature alarm (> 185 degrees Fahrenheit) for bearing 8 was reached. The bearing was inspected on June 22, 2023 and the bearing was found to be in good condition, with no bearing damage identified. The high temperature alarm was triggered again during operations on October 11, 2023, and on October 28, 2023, the bearing was again inspected and the bearing remained in good condition. The bearing was again inspected during the unit's March-April 2024 maintenance outage, and it remained in good condition.

The investigation determined that the temperature reading that was triggering the alarms did not match the reading communicated to NSPI's real-time generation monitoring system, the Distributed Control System ("DCS"). Thus, during the March-April 2024 maintenance outage, NSPI replaced the sensor that was suspected of providing inaccurate temperature readings with a new sensor. The new sensor had the advantage of measuring the temperature of the bearing metal directly, rather than the temperature of the oil coming off the bearing (which is how the old, faulty sensor worked). Once installed, bearing metal temperature readings were observed to be in line with those received by the DCS. This resolved the issue of the high temperature alarms and allows for continued operation of the bearing, which was found to be in good condition. The Root Cause Analysis was not able to determine the cause of the high temperature readings (though it was expected to involve electrical interference), which remains under investigation and are subject to two recommendations that were expected to be completed by December 2026. We confirmed with NSPI that the threat of this issue occurring elsewhere in the fleet is low as the conditions in play here were unique to Tufts Cove 3.

The second Root Cause Analysis impacting Tufts Cove was a March 4, 2026 Root Cause Analysis addressing a series of condenser tube saltwater leaks at Tufts Cove 3 in 2022 and 2023, which led to derates and a forced outage. Tufts Cove 3 is equipped with a surface condenser that uses seawater from Halifax Harbour for cooling. The performance of the condenser directly affects Tufts Cove 3's performance, including thermal efficiency and the ability to maintain full load. The condenser contains approximately 11,900 tubes, with most being admiralty brass and others near the condenser center (where risk of corrosion and ammonia grooving is highest) being 90% copper and 10% nickel. Tube integrity is crucial, because leakage allows seawater into the condensate/feedwater cycle, requiring immediate derate or shutdown to avoid equipment damage.

Over an approximately one-year period from early 2022 to February 2023, Tufts Cove 3 experienced nine separate condenser tube leaks. Inspection during outages identified significant inner-diameter wall loss, sometimes approaching 90%, particularly in the high-risk zones (with the copper-nickel tubes). Tubes adjacent to leaking tubes were also found to have demonstrated accelerated degradation and were proactively plugged, with about 200 tubes being plugged in response to these events. Given these events, during Tufts Cove 3's annual outage in 2023, NSPI elected to perform a 100% eddy-current (electromagnetic) inspection to determine the extent of degradation and mitigate future risk. This led to the plugging of approximately 500 additional tubes.

The investigation found that all condenser tube leaks originated from the inside of the tubes, confirming that seawater-side mechanisms were responsible for the wall loss observed. There was no evidence to suggest the presence of ammonia grooving or stress-corrosion cracking, further supporting the conclusion that seawater-side erosion-corrosion was the dominant mechanism. Thinning was most pronounced in the high-risk zones, where higher “turbulence” and elevated cooling water speeds are expected.

The Root Cause Analysis found that NSPI’s condenser maintenance and inspection program was executed as intended, and that NSPI’s operational and maintenance response to each tube leak was timely and aligned with industry guidance. The Root Cause Analysis did identify several improvements to NSPI’s practices, which were codified in recommendations, most of which have since been completed. A particularly critical conclusion of the Root Cause Analysis stated: “Given the extent of tube degradation, additional failures are likely without significant refurbishment.” In discussions with NSPI, NSPI indicated that it is following its risk-based maintenance program, which calls for capital investments in 2026 and retubing at Tufts Cove 3 in 2027, which will be part of NSPI’s ACE plan. NSPI also indicated the success of the investigation and tube plugging operations, which have greatly reduced tube leaks at Tufts Cove 3. We reviewed NSPI’s reported outages and derates and found only one instance of a condenser tube leak at Tufts Cove 3 during the Audit Period.⁴⁴²

The third Root Cause Analysis impacting Tufts Cove was a February 22, 2026 Root Cause Analysis addressing a steam leak in the main steam line (“MSL”) at Tufts Cove 2 in August 2022. The MSL transports high-pressure steam exiting from the boiler to the inlet of the turbine. The MSL consists of 12-inch and 8-inch nominal diameter chrome alloy piping, and the majority of the MSL system has been in service since the date of construction (1972). The MSL is supported by a series of support hangers designed to accommodate thermal expansion. A significant risk associated with systems like the MSL is the potential for creep damage, which is the deformation of a material caused by stress over time that is accelerated at high temperatures. In the later stages of creep damage, micro defects like cracks and voids form which can weaken the material, leading to propagation and joining of the cracks and eventual failure. Another MSL failure risk is fatigue, which is caused by cyclic loading over time, and which can create and exacerbate cracks to the point of failure. Creep and fatigue can combine: creep weakens materials, making them prone to fatigue crack initiation or initiating micro-cracking on its own, while cyclic loading can cause the cracks to propagate by fatigue which accelerates failure.

On August 24, 2022, during start-up activities at Tufts Cove 2, a leak on the MSL was discovered prior to reaching full system pressure. During initial inspection, “a visible circumferential direction crack at [a] piping circumferential weld location was discovered.” NSPI then removed insulation on the MSL and inspected the entire segment of the MSL and associated welds, finding three additional locations requiring major repair/removal. Given these findings, NSPI then engaged a third-party consulting and

⁴⁴² 2025 FAM Annual Report, tab A6 (4b), row 64.

inspection firm (Acuren and Wayland Engineering Ltd.) to conduct detailed inspection of the entire MSL. Two additional major repair locations were identified during this inspection.

The outage lasted from August 24, 2022 to December 11, 2022, when the unit was returned to service. The forced outage overlapped with the unit's annual planned outage, scheduled for September 9, 2022.

The Root Cause Analysis divided its findings across four areas of MSL identified issues. First, for the initial circumferential crack identified immediately following the August 24, 2022 forced outage, the Root Cause Analysis concluded:

During the follow-up detailed inspections and repairs, it was found that the first turndown “90deg elbow” (between Pipe support MS-2 and Weld MS-45) was seemingly over-rolled to approximately 85deg. It was concluded that this over-rolled likely occurred during manufacture of the elbow, and became part of the piping system installation as the piping spools were likely mechanically moved into positions. The impact on the geometry from the elbow to the piping, when mechanically moved into position, was likely to induce extra piping stress, which contributed to pipe distortion...[and] increased creep damage and crack propagation...

In repairing this section of the MSL, NSPI removed the damaged weld and corrected the angle of the piping to mitigate the risk of creep-fatigue at that location.

Second, for the identified 9.25-inch longitudinal crack identified between MSL hangers MS-1 and MS-2, the Root Cause Analysis found that “[l]ow wall thickness associated with manufacturer defects, causing elevated localized pipe stress, which contributed to the accelerated creep-fatigue failure crack formation and propagation at the longitudinal [crack]...” The remaining two instances of cracking and wall-thinning were results of “creep damage in a steam line that is subject to high stress and high temperature” and “general corrosion and/or erosion with piping of this age.”

The Root Cause Analysis contained three recommendations, including to increase the quantity of inspection locations for high energy piping across the fleet, enhance the program to include ultrasonic thickness checks of piping downstream of the boiler stop valves across the fleet, among other enhancements. The Root Cause Analysis notes that these enhancements were developed and adopted in 2023, well in advance of the completion of the Root Cause Analysis, and sustained since.

The fourth Root Cause Analysis, completed on March 4, 2026, related to an extended period of sustained increase in Drain Cooler Approach (“DCA”) temperature at Tufts Cove 3’s Feedwater Heater 4 (“FWH-4”) beginning in 2020. Tufts Cove 3 uses a multi-stage feedwater heating system; FWH-4 is part of the high-pressure heating train and is responsible for pre-heating feedwater using extraction steam. Proper performance of FWH-4, including maintaining acceptable DCA temperatures, is required to ensure reliable condensate heating, stable drain flows, and reduced turbine water induction risk. According to the Root Cause Analysis:

FWH-4 contains a shell-and-tube bundle with a dedicated Drain Cooling Zone (DCZ), where condensate must be sub-cooled before cascading to the next heater. Level control is achieved using a magnetic level indication column and a Guided Wave Radar (GWR) transmitter, operating around the OEM-recommended 8–9 inch setpoint. When DCA rises, subcooling is reduced, the specific volume of drains increases, and cascade drain systems can become restricted—all of which negatively affect unit load capability.

Since 2004, DCA temperatures mostly stayed between 30 and 40 degrees Fahrenheit, but in 2020, temperatures increased to above 55 degrees, which affected heater performance and drain operability. In response, NSPI undertook a structured diagnostic approach including trending, level-height experiments, borescope checks, leak tests, and ultimately a full shell cut to directly inspect the Drain Cooling Zone (“DCZ”). This inspection revealed multiple cracks/holes in the DCZ plate, allowing steam intrusion into the DCZ, preventing normal subcooling. (The underlying cause of the DCZ damage could not be definitively confirmed, but “manufacturing-related factors were considered possible.”) A new DCZ plate was fabricated and installed, restoring DCA performance to the best values observed in over 20 years and returning heater operation to normal.

The issue identified by NSPI, which arose in 2020, persisted for about four years until it was resolved in late 2024. NSPI’s Root Cause Analysis suggests that the “elevated DCA impaired condensate subcooling in the Drain Cooling Zone (DCZ), restricted cascade drain flow, and at times introduced operational limitations and derates...” During discussions, NSPI personnel indicated that the “operational limitations and derates” were minimal, and that in instances where the unit was impacted in reaching maximum load under certain operating conditions, plant operating staff made adjustments to the FWH-4 drain valve that allowed the plant to get to maximum load. NSPI also underscored that its focus during this period was to address the issue associated with FWH-4.

The fifth and final Root Cause Analysis relates to a December 15, 2025 Root Cause Analysis assessing a November 22, 2024 event at Tufts Cove 2 in which the unit was forced offline following a planned maintenance outage due to elevated vibration levels. Tufts Cove 2 is a three-cylinder machine comprising of a high pressure (“HP”), intermediate pressure (“IP”), and low pressure (“LP”) turbine whose shafts are rigidly coupled together in line. Steam travels through the machine, flowing from the high to low pressure sections and driving the three rotors (HP, IP, LP) via their various stages of blading, before being exhausted into the condenser. During maintenance activities, there is a risk that the rotors will become imbalanced before being placed back into service, which can result in machine vibration. Vibration can occur for numerous reasons and the Root Cause Analysis notes that “[t]roubleshooting and resolving high vibration can be a complex task and is a specialized field.” Options for rebalancing machines are also numerous, and it is typical practice by NSPI to engage the OEM to assist in analyzing and troubleshooting vibration issues and determining next steps.

On September 13, 2024, Tufts Cove 2 was taken offline for its scheduled major annual outage; based on accumulated operating hours, the primary scope of the turbine work included detailed inspections of both the HP and IP sections. According to the Root Cause Analysis:

Following completion of inspection and repair activities, final rotor alignment was performed and re-assembly completed. During the initial run-up of the unit for return to service on November 22, 2024, excessive vibration was observed. The OEM specialist mobilized to support the restart and monitor vibration identified a potential radial rub near the #4 Bearing probes, which may have caused shaft vibration. Further attempts to restart the unit were made. The first attempt was after approximately 1 hour, and the second attempt after overnight cooling; both were unsuccessful.

At this point, NSPI decided to disassemble the unit and investigate the cause of the issue. NSPI removed the IP outer cover to check both the #3 and #4 inner and outer glands, where radial rub was noted on #4's inner and outer segments. The #4 gland radial clearances were increased, but in conducting subsequent "trial runs," the unit continued to trip due to high vibrations. NSPI conducted additional inspections and adjustments, including to the IP and LP rotors' trim balances, but the unit continued to trip in attempts to run the unit. The Root Cause Analysis explains NSPI next steps and issue resolution:

Following this final attempt December 12, 2024, NS Power elected to remove the HP and IP spindles for low-speed balancing. The OEM mobilized their Field Technical Services (FTS) team and low-speed balancing equipment to the site. The unit was disassembled, the HP and IP spindles were removed, and both were low-speed balanced. After reinstallation, coupling alignments were performed, including alignment corrections between the HP and IP sections by shifting the No. 2–3 pedestal and lowering Bearings No. 1 and 2.

Upon completion of the mechanical rebuild, the OEM resource was again mobilized to support the restart and monitor vibration performance. The subsequent run-up January 6, 2025 successfully reached operating speed at 3600 RPM. While vibration levels on Bearings No. 5 and 6 were initially in the high Zone B range (Based on ISO Code 10816), a trim balance on the LP rotor was recommended and implemented. Subsequent run-ups showed improved vibration performance, and the unit was successfully synchronized to the grid the same day.

The Root Cause Analysis notes that "[s]ince the vibration issues were not present before the planned maintenance outage, the investigation focused on the work performed during the outage to determine the cause of the imbalances discovered on the HP and IP rotors." That investigation found two issues: (1) several rotor blades exhibited a loss of welding material at the shroud-to-blade attachment points and (2) significant deposits were observed on the underside of the blades. The Root Cause Analysis concluded that "[b]ased on a review of the work performed during the planned maintenance outage, the most likely contributors" were:

- Missing welds - Welds added to rows 9 through 12 in 2012 may have been a minor contribution to imbalance due to the subsequent losses of rotating mass but is not expected to have been the main contributor. This was also assessed by OEM balancer and determined to have low-moderate impact. The degraded welds observed during the outage were originally installed by the OEM in 2012 at their [REDACTED] facility.
- Rotor Cleaning - Media or Grit blasting is a common surface preparation method used in turbine maintenance to clean blade surfaces and remove deposits. However, if not carefully controlled, this process can lead to an imbalance by removing material unevenly resulting in uneven mass distribution across the rotor. Some of the hard-to-reach areas

(under shroud, under blade deposits) need to be dressed manually. **As sandblasting was performed during the outage and significant under blade deposits were noted that required manual dressing, these activities are considered to be the most probable cause contributing to machine imbalance in this case.** Although there is a potential risk, NS Power has effectively demonstrated through experience that a re-balancing following media-blasting is rare. This approach relies on consistent application of cleaning activities around the rotor periphery. The decision to omit low-speed balancing post-media blasting is a practice that is not uncommon and there was no OEM site management recommendation to include this activity. To help prevent future reoccurrence, the details of this event will be shared across the fleet and a procedure for rotor cleaning will be documented to help ensure consistent execution.

The contractor that performed the sand-blasting work ([REDACTED]) is a commercial and industrial contractor in business since 1990, and NSPI indicated that [REDACTED] has completed this work and similar work for NSPI at Tufts Cove and other thermal generators in the fleet over several years. NSPI indicated that [REDACTED] scope of work was to sandblast the steam path and steam sealing areas of both the HP and IP spindles, which NSPI would have already removed and prepared for sandblasting. NSPI explained that if any leftover deposits remained after sandblasting, they were removed manually by NSPI millwrights. At the time of this event, no formal written procedure for [REDACTED] Painting's scope of work existed. NSPI indicated that it completed a walkdown of the spindles with the contractor prior to the work and provided verbal instructions of precautions to take during the process, such as maintaining a 6 to 8- inch nozzle gap from the surface, and not to dwell on any area for an extended period to maintain an even and limited removal of material.

As the Root Cause Analysis makes clear, the collective work done during the planned maintenance outage likely did not sufficiently remove deposits from the rotor blades, which became the most probable cause of the imbalances that caused this outage. NSPI's position is that [REDACTED] did not fail to complete its scope of work, and we agree, insofar as it is NSPI's role to manually remove any deposits not cleaned by sandblasting. NSPI has since begun development of a formal quality practice to standardize NSPI's approach to rotor cleaning, consistent with the recommendation contained in the Root Cause Analysis. NSPI stated that this practice will include both sandblasting activities and the manual removal of deposits performed by NSPI personnel.

As a result of this issue, Tufts Cove 2 was offline from November 22, 2024 through January 6, 2025. When asked if it had estimated the incremental FAM cost of this outage, NSPI indicated that it did not conduct this calculation. NSPI did indicate that there was additional non-FAM costs associated with the capital project for this work. We recommend NSPI provide an estimate of the incremental FAM costs incurred during this event.

X.B.3.c. Diesel-Fired Combustion Turbines

X.B.3.c.i. Performance During Audit Period

NSPI's seven 33 MW combustion turbines' performance during the Audit Period saw, in some cases, elevated DAFORs in 2024. Performance improved considerably in 2025, as is shown in Figure X-20 below. The units' Availability Factors were consistent and generally positive during both years. Incidence of a unit exceeding the GADS standard for the time period is highlighted in green; a red highlight indicates the opposite. NSPI's units performed generally better than industry average regarding availability factor, but lower than average on DAFOR. In prior discussions, NSPI has stated that lower capacity factors on the combustion turbines are correlated with elevated DAFORs.⁴⁴³

Figure X-20: DAFOR, Availability Factors of NSPI's Seven Combustion Turbines (2024-2025)⁴⁴⁴

Unit	DAFOR (2024)	DAFOR (2025)	GADS EFOR Standard	Availability Factor (2024)	Availability Factor (2025)	GADS AF Standard
Burnside 1	93.9%	8.2%	23.2%	60.3%	97.2%	84.2%
Burnside 2	23.5%	13.0%	23.2%	93.4%	93.3%	84.2%
Burnside 3	39.8%	7.6%	23.2%	91.7%	93.7%	84.2%
Burnside 4	19.0%	69.2%	23.2%	95.1%	70.5%	84.2%
Victoria Junction 1	0.7%	7.5%	23.2%	97.1%	99.2%	84.2%
Victoria Junction 2	40.2%	2.4%	23.2%	96.6%	64.9%	84.2%
Tusket	93.8%	43.1%	23.2%	73.4%	95.8%	84.2%

We also reviewed the combined output of the units compared to their expected output, as modeled by NSPI using PLEXOS. In the past, NSPI's PLEXOS modeling has forecasted very little generation output from the combustion turbines, while in reality the units run much more than expected. In this Audit

⁴⁴³ 2020-2021 Audit Report, pages 204 to 205.

⁴⁴⁴ NERC GADS data,
<https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.nerc.com%2Fglobalassets%2Fprograms%2Frapa%2Fgads%2Freports%2Fgenerating-unit-statistical-brochure-2-2024---all-units-reporting.xlsx&wdOrigin=BROWSELINK>

Period, actual output was similar to the prior Audit Period (35,367 MWh in this Audit Period vs. 33,855 MWh in the prior Audit Period). Audit Period output data compared to forecast is shown in Figure X-21.

Figure X-21: Combustion Turbine Output Combined, Forecast vs. Actual⁴⁴⁵

Year	Forecast Generation (MWh)	Actual Generation (MWh)	Difference (%)
2024	32,616	15,111	-54%
2025	14,615	20,256	39%
Total	47,230	35,367	-25%

X.B.3.c.ii. Performance Test Results at Tusket, Victoria Junction 1, Burnside 1-4

During the Audit Period, NSPI conducted real power performance tests on six of the seven units. The performance test for each unit tested for its summer reactive power capabilities at minimum load pursuant to NERC Standard MOD-025-2. Tusket's test demonstrated a gross and net real power (29.9 MW) that about matched its currently declared NPCC value (30.0 MW). Victoria Junction unit 1's gross and net real power (27.7 MW) were 7.6% below its NPCC declared value.

The results for the Burnside units were more mixed. Burnside 1's results showed a gross and net real power (28.4 MW) that was 5.4% below its NPCC rated value of 30.0 MW. The other three Burnside units tested *higher* than their respective NPCC rated values, which are all 30 MW. Burnside 2 tested at 30.9 MW (+3.0%), Burnside 3 at 33.2 MW (+10.6%), and Burnside 4 at 32.6 MW (+8.7%).

X.B.3.c.iii. Root Cause Analysis Review

We were provided with and reviewed two Root Cause Analyses related to diesel-fired CT units.

The first was a December 5, 2025 Root Cause Analysis assessing a March 7, 2024 event at Burnside 1. On that date, the unit tripped due to high vibration; with the unit offline, an inspection found damage to stage 9 of the High Pressure Compressor, which was caused by a liberated turbine blade. NSPI engaged two third-party experts (██████████) and the original equipment manufacturer ("OEM"), Wood Group Pratt & Whitney ("WGPW") for assistance. The engine at issue was purchased by NSPI from the OEM in 2021 as a refurbished engine, which was subject of CI C0001222 BGT1 Engine Exchange.

During teardown and inspection, the OEM discovered extensive damage to various components in the turbine. At NSPI's request, the OEM then sent a sampling of 9th stage compressor blades and the 9th state stator assembly for laboratory analysis to determine the cause of failure. The laboratory analysis concluded that the cause of failure was caused by high cycle fatigue and noted that antifriction coating on the blade dovetail had mostly worn away. The OEM stated that this was "highly unusual" and claimed

⁴⁴⁵ Q4 2024 FAM Report, 2(3); Q4 2025 FAM Report, 2(3).

that fatigue failures are not common under normal engine operating conditions. The OEM claimed that the stage 9 compressor blades were inspected to applicable inspection standards and therefore there were no prior indications of failure that could have been found and addressed prior to installation of the compressor blades and stator.

The third-party investigation ([REDACTED]) reviewed the OEM's refurbishment of the engine in comparison to industry standards, and the lab analyses performed on the failed components. The third-party investigation concluded that based on the short duration that the engine was in the shop (19 days), it was likely that much of the refurbishment work was accomplished prior to the date the engine was pulled from inventory. The OEM refurbishment report supports this view by referring to the engine as previously "refurbished" and although the refurbishment report does not indicate the completion date for the reported tasks, several of the photos showing assembled engine components are dated as early as 2015. The third-party investigation stated that they accept in good faith that the tasks described in the report were accomplished at some point in the past, however lab analysis, site inspections, and component failures suggest that portions of the engine may have been in fired operation by another utility after the completion of the refurbishment tasks. The third-party investigation found several components in the engine that were in a condition that contradicted or questioned the refurbishment work performed by the OEM in some cases. The Root Cause Analysis therefore concluded:

Based on the OEM's documented work scope, these findings from the third-party expert confirm that the inspection and refurbishment performed prior to NS Power taking ownership did not meet industry best practices and therefore created a possibility that important flaws were overlooked. This is especially relevant to the failed 9th stage HPC blade. The OEM had claimed in their engineering analysis (Appendix A) that the blades had been inspected but the third-party expert's review revealed that the 9th disk/blade assembly was not disassembled, which would have prevented a thorough inspection/overhaul.

During the period where this engine was taken out of service, which lasted until December 1, 2024, NSPI received a leased engine on May 10, 2024. NSPI inspected that engine and determined it was deemed unfit by NSPI, a determination with which the OEM agreed. A second leased engine arrived on July 24, 2024 and was placed into service and remained in service until December 11, 2024, when it was returned to the OEM.

To resolve these issues, NSPI negotiated with the OEM (WGPW) and pursued the full cost of the event, eventually agreeing to a 50% reduction in final refurbishment costs and a full waiver of costs associated with the leased replacement engine. The total value of this outcome to NSPI was \$ [REDACTED] USD; this total represents avoided costs, and thus involved no refunds. The costs involved were not FAM costs. NSPI stated that despite the third-party investigation findings, the technical evidence could not conclusively attribute the failure to a single discrete refurbishment action. NSPI stated that its agreement to these terms was based in part on its long-standing commercial relationship with [REDACTED] which includes ongoing access to specialized parts, service capabilities, spare engines, and technical expertise that are critical to maintaining the reliability of NS Power's legacy combustion turbine fleet.

When we requested NSPI's estimate of the FAM costs associated with this event, NSPI indicated that it did not conduct this calculation. NSPI further noted that the leased engine allowed Burnside 1 to remain operational during the time the refurbished engine was out of service, avoiding displacement of generation to higher-cost resources. We agree with this point, at least for the period when the leased engine was in place (July 2024-December 2024). However, there was a period where the unit was fully offline, prior to receipt of a leased engine (March 8, 2024-July 24, 2024). Still, it is unlikely this event resulted in significant incremental FAM costs, as Burnside 1 is a high-cost peaking unit rarely operated. Given the nature of this event, however, NSPI should confirm that no incremental FAM costs were incurred, and if they were, to refund those costs to customers, who should bear no costs associated with this event.

Further to the Root Cause Analysis, NSPI is in the process of conducting third-party audits of any engine or free turbine exchanges to evaluate in detail the history of refurbishments performed by the vendor on high-risk areas such as High Pressure Compressors stages 9-15 prior to acceptance and delivery, with that work expected to be completed in September 2026.

The second CT-related Root Cause Analysis was completed on December 17, 2025 and related to an event that occurred on July 13, 2020. On that date, during a period of warm weather and increased demand, four of the available five CTs tripped within a four-hour window of the system operator attempting to place them in service. The Root Cause Analysis found two issues. First, for some trips, the amount of fuel being fed to the engine at startup was too high, given the (high) ambient temperature. Higher temperatures reduce air density and oxygen availability, meaning less fuel is needed for a proper start, and excess fuel on a hot day can trigger a trip. The amount of fuel at startup of these units is set on site through a static setting that can be adjusted by the CT operators. To remedy this issue, NSPI requested the OEM provide a single flexible and reliable setting for startup fuel. The Root Cause Analysis noted that the tradeoff for this approach, which reduces the amount of fuel at startup, is that winter starts may be slower. Still, this approach should help minimize the likelihood of a high-temperature trip in the future, but CT winter performance should be monitored.

The second issue that caused some CT trips were free turbine vibrations due to uneven thermal contraction during short-interval restarts, driven by inadequate cooldown time in warm conditions. When a CT unit is taken out of service, the control system automatically initiates a cool down sequence of 50 minutes, after which the unit will allow itself to be restarted, as was the case, for example, with a trip of Burnside 1 and 2, which were recalled at 18:40 on the day in question after being shut down at 17:30. However, there is no instrumentation on the unit to measure temperature and ensure that the unit has sufficiently cooled. NSPI solicited feedback from the OEM and other knowledgeable companies and confirmed that uneven thermal expansion is common during hot starts. To address this issue, NSPI is evaluating operational limits on short-cycle restarts during hot weather and tight grid conditions, an assessment that is due to be complete in December 2026.

X.B.3.d. Lingan

X.B.3.d.i. Performance Test Results

During the Audit Period, NSPI conducted real power performance tests at Units 1, 2, and 3. Unit 1 produced [REDACTED] MW of gross real power, [REDACTED]% above its NPCC declared value of [REDACTED] MW, and [REDACTED] MW of net real power, [REDACTED]% above its NPCC declared value of [REDACTED] MW. Lingan Unit 2's real power test showed a gross real power of [REDACTED] MW, [REDACTED]% below its NPCC declared value of [REDACTED] MW, and a net real power of [REDACTED] MW, which is [REDACTED]% below its NPCC declared value of [REDACTED] MW. Lingan Unit 3's real power test showed a gross real power of [REDACTED] MW, [REDACTED]% above its NPCC declared value of [REDACTED] MW, and a net real power of [REDACTED] MW, which is [REDACTED]% above its NPCC declared value of [REDACTED] MW. These were the first tests of Units 1, 2, and 3 since 2021.

X.B.3.d.ii. Status and Operation of Lingan 2

The Board considered the issue of the retirement of Lingan 2 and its relation to the commencement of the NS Block volumes in a February 8, 2022 Decision.⁴⁴⁶ The Board noted that in NSPI's integrated resource plan ("IRP") filed in 2020, Lingan 2 was assumed to be retired once the NS Block commenced.⁴⁴⁷ However, it was later noted that NSPI's plan would be to not retire Lingan 2 until one year following NS Block commencement, at minimum.⁴⁴⁸ A party to the proceeding in M10206 argued that the Board should consider disallowing any costs related to Lingan 2 following commencement of the NS Block.⁴⁴⁹ In its Decision, the Board found that review of Lingan 2 operating costs would typically be done in the FAM Audit process, but since the next audit would not be completed for two years, the Board therefore advised NSPI "that it will not permit recovery of operating costs of Lingan 2 beyond August 15, 2022, without further order of the Board."⁴⁵⁰ The Board therefore required NSPI to "seek specific approval if it wants to recover those operating costs" associated with operation of Lingan 2 beyond August 15, 2022.⁴⁵¹

In a June 30, 2022 letter to the Board, NSPI stated that it would "phase out the operation of Lingan 2 such that it will not be used for economic dispatch after August 15, 2022."⁴⁵² However, because of "near-term capacity shortfalls...Lingan 2 will be placed in cold reserve and available on 2 weeks' notice, if required, to provide firm capacity and to maintain an adequate Planning Reserve Margin during the 2022/23 winter season."⁴⁵³

⁴⁴⁶ NSUARB, "Decision," M10206, February 9, 2022 ("February 2022 Board Decision").

⁴⁴⁷ February 2022 Board Decision, paragraph 241.

⁴⁴⁸ February 2022 Board Decision, paragraph 241.

⁴⁴⁹ February 2022 Board Decision, paragraph 242.

⁴⁵⁰ February 2022 Board Decision, paragraph 245.

⁴⁵¹ February 2022 Board Decision, paragraph 245.

⁴⁵² NSPI, "Nova Scotia Power – Lingan 2," M10652, June 30, 2022, PDF pages 1 to 2 ("NSPI June 2022 Letter").

⁴⁵³ NSPI June 2022 Letter, PDF page 2.

Regarding sustaining capital investments associated with Lingan 2, NSPI reported \$1,429,958 in sustaining capital in 2024 and an additional \$3,763,431 in 2025. These capital projects, which included various refurbishment activities on unit assets, including the boiler, the precipitator, the ash system, and mills, were the subject of capital investment requests at the Board including C0059283 (LIN2 2023/24 Winter Capacity Requirements), C0067023 (LIN2 2024/25 Capacity Requirements), and C0082195 (LIN2 2025/26 Capacity Requirements).⁴⁵⁴

Going forward, the IESO Nova Scotia has taken over responsibility for long-term system planning. In the IESO's recent 10-Year System Outlook, Lingan Unit 2 is forecasted to remain available until "2029/2030," at which point it is retired.⁴⁵⁵ This is a revision from NSPI's 2025 10-Year System Outlook, which had forecasted the retirement of Lingan Unit 2 in the Winter of 2027/2028.⁴⁵⁶ The IESO stated:

The thermal retirement schedule complies with the 2030 coal phase-out targets. Previous 10-year load and resource outlooks presented retirements of Trenton 5 and Lingan 2 in Winter 2027/2028. Based on the current expected in-service dates for fast-acting generation, IESO Nova Scotia finds that these units will be required through Winter 2029/2030 in order to maintain adequate PRM. Trenton 5 and Lingan 2 can only be retired once new fast-acting generation needed to replace the firm capacity they provide is in service and reliable operation of the new units has been established.⁴⁵⁷

Given the IESO's position, NSPI would need to continue to sustain Lingan 2 for an additional 2-3 years. For the remainder of the Lingan units, the IESO is forecasting a conversion of Units 1, 3, and 4 to burn HFO in "2029/2030."⁴⁵⁸

Regarding the operation of Lingan 2 in commitment and dispatch, we address that issue in the next chapter of this report.

X.B.3.e. Point Aconi

X.B.3.e.i. Performance Test Results

Though it occurred following the end of the Audit Period, NSPI conducted a maximum real power test (pursuant to NERC standard MOD-025-2) at Point Aconi on January 5, 2026. This was the first such test on the unit since 2022. Point Aconi tested within 1 percent of its NPCC declared value for gross real power and 2 percent of its NPCC declared value for net real power.

⁴⁵⁴ NSUARB, Letter re: M11322 – Nova Scotia Power Inc. CI 51761 LIN2 2022/2023 Winter Capacity Requirement - \$2,512,341, M11322, February 8, 2024.

⁴⁵⁵ IESO Nova Scotia, "2026 10-Year System Outlook Report," June 26, 2028 (sic), Table 3.

⁴⁵⁶ IESO Nova Scotia, "2026 10-Year System Outlook Report," June 26, 2028 (sic), page 17.

⁴⁵⁷ IESO Nova Scotia, "2026 10-Year System Outlook Report," June 26, 2028 (sic), page 17.

⁴⁵⁸ IESO Nova Scotia, "2026 10-Year System Outlook Report," June 26, 2028 (sic), Table 3.

X.B.3.e.ii. 2024 Forced Outages for expansion joint failures

On three separate occasions in 2024, Point Aconi was forced offline due to failures of an expansion joint on the air supply to a combustor return leg. Collectively, the three outages totaled 308.76 hours and spanned the periods August 16-August 18, August 19-August 20, and August 25-September 4.⁴⁵⁹ After the initial failure was repaired, the replacement joint failed within 24 hours, causing a second forced outage. A limited inspection identified abnormal material buildup in the return leg, though ash flow was still occurring. NSPI noted that some ash accumulation is normal after extended operation, and occasional expansion joint failures are expected.

Following repair, the joint failed again just five days later, causing a third forced outage, which lasted from August 25 until Point Aconi's annual planned outage began on September 4. During the planned outage, the OEM conducted a detailed inspection which determined that the return leg was plugged, restricting ash circulation, causing overheating of the expansion joint and subsequent failure. The blockage consisted of mainly non-combustible material, and NSPI noted that leading up to the outages, the unit was operating with higher coal blend ratios for testing purposes as it was a lower cost option; NSPI noted too that testing closer to the annual outage would allow for internal visual inspection of any impacts associated with the coal. NSPI stated that the coal blends are more sensitive to particle size due to increased non-combustible content, contributing to material buildup.

NSPI's corrective actions included optimizing fuel sizing under higher coal-firing conditions, such as adjusting crusher grate openings. NSPI reported that since implementation of the fuel crusher adjustments, ash circulation has remained stable and no further related expansion joint failures have occurred.

We confirmed NSPI did switch to higher coal fuel blends (and lower petcoke) starting in July, and reaching as low as █% petcoke by July 29 (with mid-sulfur and LSL coal making up the rest) and 0% petcoke/█% coal starting August 5 in order to lower the sulfur content of Point Aconi's fuel as it faced tight SO₂ emissions constraints in 2024. This series of outages represents one impact of such experimental fuel blends and could challenge NSPI in the future as emissions constraints become tighter each year.

X.B.3.f. Point Tupper

X.B.3.f.i. Performance Test Results

On November 20, 2025, NSPI conducted a maximum real power test (pursuant to NERC standard MOD-025-2) at Point Tupper. This was the first such test on the unit since 2021. Point Tupper's gross real power tested at █ MW, █% below its NPCC declared value (█ MW), while its net real power tested at █ MW, █% below its NPCC declared value of █ MW.

⁴⁵⁹ 2024 FAM Annual Report, tab A6 (4b), rows 37-39.

X.B.3.f.ii. October-November 2024 forced outage

On October 26, 2024, Point Tupper was forced offline in an outage that would last 552.37 hours until November 18, 2024.⁴⁶⁰ NSPI explained that the cause of the outage was a generator trip on under-excitation protection. NSPI brought personnel from the OEM to the plant as part of the event response to advise during the inspection and repair. The trip was traced to a failure within the rotating brushless exciter assembly, specifically involving damage to rectifier diodes and associated fuses. Subsequent inspection identified carbon and dirt accumulation on the exciter components, which contributed to electrical arcing across an insulator and the resulting component failures.

NSPI explained that its corrective actions included a full teardown, cleaning, inspection, and replacement of all diodes, fuses, and damaged insulating components, followed by functional testing prior to returning the unit to service. The frequency of air filter changes was also adjusted to bi-weekly as per OEM field representative recommendation.

NSPI explained that this outage is related in equipment type, but not identical in circumstances, to the Point Tupper Unit 2 exciter event discussed in Section X.B.3.f of the 2022–2023 Audit Report. Following the 2022 exciter failure, NSPI explained that it completed corrective actions including component testing and replacement based on results, enhanced inspections, and updates to maintenance and monitoring practices for the exciter system, which were implemented during the intervening period.

Following the 2024 event, the OEM recommended a cleaning schedule for the exciter of every two years. Point Tupper had a recurring preventative maintenance work order in place for inspection and cleaning which matched this schedule prior to the event, last completed in October of 2023. Following the 2024 event, NSPI has updated the frequency of this preventative maintenance to annually as an additional precaution. The OEM also suggested that an engineering study could be performed to validate cleanliness improvements that may be achieved by installing baffles. NSPI stated that since the 2024 event, plant personnel have engaged the OEM to explore this option. Given the impact of outages like these, we include a recommendation that NSPI complete its corrective measures and update the Board with an explanation of the measures ultimately implemented.

X.B.3.f.iii. Root Cause Analysis Review

We were provided and reviewed two Root Cause Analyses related to Point Tupper. One event associated with the Root Cause Analyses occurred in the prior Audit Period.

The first Root Cause Analysis, completed March 4, 2026, relates to a June 25, 2023 event that kept Point Tupper offline until August 2, 2023. On June 25, 2023, the plant's two circulating water ("CW") pumps tripped due to ground faults at separate times. A forced outage was initiated until the west CW pump was repaired and returned to service, which allowed the unit to operate in a derated state starting

⁴⁶⁰ 2024 FAM Annual Report, tab A6 (4b), row 43.

July 12, 2023 until the east CW pump refurbishment was completed (which occurred on August 2, 2023). Both CW pump motors failed megger tests by plant electricians and were sent for damage assessment, cleaning, and refurbishment to a third-party service provider.

The cause of the two failures were “a combination of contamination and moisture” that “contributed to the motor failures.” The Root Cause Analysis stated:

The West motor was in operation for a week when it failed, and therefore there should not have been sufficient ambient moisture in the windings to result in failure. However, if additional moisture was introduced by high humidity air around the motor due to open doors, or direct water ingress due to a roof leak, combined with the existing level of contamination, a ground fault could occur. Additional moisture could have been present if all or some of the cabinet heaters had failed or were not on as well.

Similarly, the East motor failed with a ground fault after a only few minutes of operation, likely caused by the combination of contaminated windings (dirt/salt/oil) and a moist operating environment. Additional moisture could have been present if all or some of the cabinet heaters had failed or were not on.

The Root Cause Analysis further states:

Maintenance and Condition Review

No indications from the PDM or PDP programs prior to the failure date were observed. Vibrations and temperatures were normal on both motors prior to the failure. Compliance with PMs associated with the CW motors was generally quite good.

A summary of relevant Work Orders can be found in Appendix A. The work orders suggest challenges with the insulation resistance (PI) readings on the west motor, which we can see by the work orders requiring the motors to be tarped and heated to dry them out. This would not be uncommon for motors operating in this type of environment, particularly aging motors. It does, however, suggest less than ideal moisture management in the operating environment for these motors.

For the West CW motor, testing History and other factors informed an internal risk ranking of 20 during the 2021 risk ranking. Specifically, the capacitance to ground had increased from 113,400 to 510,200 between the 2018 and 2021 testing. Increased capacitance to ground values are an indication of stator winding contamination. These results suggest the motor was due for major service. This motor was sent out to 3rd party for refurbishment in 2022 (See Appendix B, Northpoint report 32182 dated May 2022). No issues upon final testing were reported and the motor was re-installed late spring of 2022. Prior to the 2023 failure, a roof leak was also found over the west motor, which has since been tarped and re-directed.

The East CW motor was deemed to be in better condition, following a refurbishment (cleaning & baking) in 2016. At time of failure, it was assessed with a risk ranking of 9 and would not have been expected to require near-term intervention.

NSPI concluded itself in the Root Cause Analysis that “less than ideal moisture management in the operating environmental for these motors” was present. NSPI also noted that “[c]abinet heaters were not fully functional on either motor at the time of failure,” and that while “[t]he operating environment is challenging, but there are opportunities to improve moisture management.” When we requested NSPI’s estimate of the FAM costs of this event, which kept Point Tupper offline for 38 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so. That calculation should include the impact of the forced outage (which lasted from June 23, 2023 to July 12, 2023), plus the period in which Point Tupper was derated (through August 2, 2023).

The second Point Tupper Root Cause Analysis, issued January 12, 2026, addressed several short-term forced outages related to turbine exhaust and differential temperatures. On April 25, 2023, the unit was in the process of returning to service when an alarm was received due to low pressure hood temperature. The start-up was aborted and a forced outage was initiated for investigation and repair, while the Root Cause was initiated in response to this event and other temperature regulation issues that had been experienced during low load operation and start-ups through the year which seemed to NSPI to have a common potential cause. The Root Cause Analysis found that the cause of these events was air ingress into heat exchangers. Repairs were made to prevent air ingress, and NSPI reported no additional incidents at Point Tupper since.

X.B.3.g. Trenton

X.B.3.g.i. Performance Test Results at Unit 6

During the Audit Period, NSPI conducted a performance test at Unit 6. The tests assessed the unit’s real power capabilities at full load pursuant to NERC Standard MOD-025-2. The tests showed that Unit 6 has a gross real power of [REDACTED] MW, [REDACTED] % below its NPCC declared value of [REDACTED] MW, and a net real power of [REDACTED] MW, which is [REDACTED] % below its NPCC declared value of [REDACTED] MW.

X.B.3.h. Port Hawkesbury Biomass

We address aspects of the PHB unit’s performance in Chapter VI and the commitment and dispatch of PHB in Chapter XI. Here, we address additional items related to PHB’s performance during the Audit Period.

X.B.3.h.i. Process Efficiency of the PHB Boiler

In a prior audit report, we recommended that NSPI incorporate the “process efficiency” of the PHB boiler in its FAM reporting.⁴⁶¹ NSPI has done so, and in this section, we review the process efficiency results.

⁴⁶¹ 2020-2021 Audit Report, page 239.

The process efficiency of the PHB boiler is calculated by summing the total electricity generation (converted to gigajoules, or “GJs”) and the total thermal energy delivered to PHP (in GJ), divided by the total energy content of the fuel burned in the PHB boiler (in GJ).⁴⁶² This metric is important in tracking the overall efficiency of the boiler, as it corrects for the cogeneration nature of the PHB plant (which can skew other metrics of efficiency, such as reported heat rates).⁴⁶³ **Figure X-22** below shows the annual process efficiency of the boiler since 2019 and contains details of the fuel and output associated with PHP’s steam offtake and NSPI’s power generation.

Figure X-22: PHB Process Efficiency (2021-2025)⁴⁶⁴

Year	Fuel to PHB (GJ)	Thermal Energy to PHP (GJ)	Electricity Production (GJ)	Total Energy to “Useful Work” (GJ)	Process Efficiency
2021	3,916,405	909,517	575,441	1,484,958	37.9%
2022	3,885,533	1,009,958	511,308	1,521,266	39.2%
2023	4,002,451	952,142	515,067	1,467,209	36.7%
2024	4,394,537	1,015,395	584,230	1,599,625	36.4%
2025	4,532,722	897,275	657,096	1,554,371	34.3%

The process efficiency data suggests the boiler continues to trend in a negative direction since 2019 and reached its lowest point in 2025 (34.3 percent). NSPI explains that “[t]he process efficiency will change from year to year depending on the quality of the fuel, the percent of boiler operating capacity used, and the operating profile of the PHP paper mill.”⁴⁶⁵ We would point out that the “quality of fuel” in 2025 was exceptionally high, with an average moisture content of biomass fuel of 50.5%, the lowest in any year since 2019. Boiler operating capacity in 2025 (60.6%) was also the highest of any year since 2019. These variables alone would not appear to explain the decline in process efficiency of the boiler in 2025, and in fact would appear to support greater boiler efficiency.

NSPI explained the results by stating that from 2024 to 2025, the balance of steam provided to the PHP mill declined and the amount of steam delivered to the generator for electricity production increased. NSPI stated that this trend resulted in a lower proportion of total energy being recovered as useful steam, down from 64% in 2024 to 58% in 2025). NSPI explained that combined heat and power operations are more efficient when a greater share of energy is delivered as useful thermal output. Still, this is a trend that should be monitored going forward and not minimized due to the complexity of the variables that can influence this performance statistic. In the IESO 10-Year System Outlook, PHB is forecasted to continue to operate in the near future and to increase its annual output (to 250 GWh) in 2030.⁴⁶⁶ NSPI, for its part, forecasts continued sustaining capital investment in PHB through 2050 at an average of \$■ million/year, including more substantial investments in 2028 (\$■ million) and 2032 (\$■ million). All this suggests

⁴⁶² 2020-2021 Bates White Audit Report, page 210.

⁴⁶³ 2020-2021 Bates White Audit Report, page 210.

⁴⁶⁴ 2022-2023 Bates White Audit Report, page 246; 2025 FAM Annual Report, A14.

⁴⁶⁵ 2025 FAM Annual Report, A14.

⁴⁶⁶ IESO Nova Scotia, “2026 10-Year System Outlook Report,” June 26, 2028 (sic), Appendix A.

that PHB will remain a contributing resource to NSPI's needs and its performance statistics should continue to be tracked and used to inform operational and maintenance decisions.

X.B.3.h.ii. Root Cause Analysis Review

We were provided and reviewed one Root Cause Analysis related to PHB.

The Root Cause Analysis, published December 3, 2025, addressed an event on May 31, 2024, when the PHB unit was forced offline due to a Low-Pressure Steam Extraction Control Valve Rod ("Rod") for the turbine had broken. Steam exiting the PHB boiler flows through a turbine, after which it exits at one of three extraction points or into the steam surface condenser. One of the extraction points is the Low Pressure ("LP") Extraction Line, which is controlled to a constant pressure by the LP Extraction Control Valve and fed to the LP Extraction Header for process steam usage. The LP Extraction Control Valve has two Rods, which are attached to a valve lifting plate that supports and operates the four sequential control valve heads used to control LP steam extraction from the steam turbine. In the event, one of the two Rods were observed and reported to be broken.

The Rod was classified by NSPI as a "critical spare" part, since it is critical to maintain reliable operation of the PHB plant and the potential operational impact associated with a failure. At the time of the event, NSPI's inventory records indicated that one spare Rod was held in inventory at the plant. However, following the event, and despite inventory records to the contrary, NSPI was unable to physically locate the Rod at the plant. Unable to locate the spare Rod, NSPI made the decision to undertake temporary repairs to the failed Rod and initiate procurement of a replacement spare, all through contact with the OEM. The broken Rod was repaired and added back to the LP Extraction Control Valve system on June 17, 2024, and the PHB unit was returned to service that same day. On July 3, 2024, PHB was removed from service for annual planned maintenance, and on July 19, 2024, the replacement Rod from the OEM was delivered to the plant. The Rod was installed and the PHB unit returned to service on August 4, 2024.

Following the restoration of service, NSPI discovered the original spare Rod located in storage during an inventory review. NSPI's subsequent review determined that the spare Rod had been relocated with a different area of the plant without the inventory system records being updated, which resulted in the inability for NSPI to physically locate the spare Rod specified in its inventory records. Following the event, and in conjunction with Root Cause Analysis findings and recommendations, NSPI implemented corrective actions to its inventory control practices, including: (1) reinforcing requirements to update system locators when materials are physically relocated; (2) improving labeling and storage identification for critical spare components; and (3) re-emphasizing expectations with storekeeping personnel regarding inventory accuracy for critical spares.

When we requested NSPI's estimate of the FAM costs of this event, which kept PHB offline for 18 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so, given that the forced outage lasted longer than what it would have been if NSPI had been able to locate the spare Rod in

the immediate aftermath of the event. That calculation should include the impact of the forced outage (which lasted from May 31, 2024 to June 17, 2024), plus the cost of repairs to the failed Rod.

X.B.3.i. Hydro Units

X.B.3.i.i. Hydrological Conditions and Output

NSPI received 1,279,567 MWh of generation from its hydroelectric assets, including Wreck Cove and the run-of-river assets in the western part of the province.⁴⁶⁷ This is a decrease of approximately 30 percent from the prior Audit Period, or 539 GWh. This is shown in Figure X-23 below.

Figure X-23: NSPI-Owned Hydroelectric Annual Output (MWh) (2022-2025)⁴⁶⁸

Year	Hydro Output (Actual, MWh)
2022	875,045
2023	943,199
2024	685,564
2025	594,003
Prior Audit Period	1,818,245
Current Audit Period	1,279,567

While several factors, including unit availability, can affect overall annual hydroelectric output, a primary contributor to the decreased hydro output in the current Audit Period were less favorable hydrological conditions. Specifically, Nova Scotia's precipitation totals during the Audit Period sharply decreased from the 2022-2023 Audit Period. Precipitation in Halifax, for example, totaled 2,186.2 mm for the Audit Period, down about 28 percent from the 2022-2023 period (which had 3,049.2 mm of precipitation).⁴⁶⁹ In fact, Halifax precipitation totals in 2024 (1,089.4 mm) and 2025 (1,096.8 mm) were the lowest annual precipitation since 2001 (1,005.8 mm).⁴⁷⁰ Moreover, relative to BCF forecast, 100% of NSPI's hydro units produced less output than forecasted in 2025⁴⁷¹ and all but one unit produced less output than forecast in 2024.⁴⁷² In all, NSPI received 538 GWh less generation from its hydro fleet than forecasted for the Audit Period.⁴⁷³ We look at three of the hydro generating facilities in the next subsection.

⁴⁶⁷ Q4 2025 FAM Quarterly Report, Q-6.

⁴⁶⁸ 2022-2023 Bates White Audit Report, page 247; Q4 2024 FAM Quarterly Report, Q-6; Q4 2025 FAM Quarterly Report, Q-6.

⁴⁶⁹ "Total Precipitation – Annual data for Halifax (Shearwater)," available at: <https://halifax.weatherstats.ca/charts/precipitation-yearly.html>.

⁴⁷⁰ "Total Precipitation – Annual data for Halifax (Shearwater)," available at: <https://halifax.weatherstats.ca/charts/precipitation-yearly.html>.

⁴⁷¹ Q4 2025 FAM Report, 9(3).

⁴⁷² Q4 2024 FAM Report, 9(3).

⁴⁷³ Q4 2024 FAM Report, 9(3); Q4 2025 FAM Report, 9(3).

X.B.3.i.ii. Wreck Cove Performance, Life Extension

Wreck Cove provided 220,961 MWh in 2024⁴⁷⁴ and 264,347 MWh in 2025.⁴⁷⁵ Figure X-24 below shows the output, capacity factor, DAFOR, and availability factors for Wreck Cove units 1 and 2 during the Audit Period.

Figure X-24: Wreck Cove Performance Metrics (2024-2025)

Metric (Year)	Wreck Cove 1	Wreck Cove 2
Capacity Factor (2024)	1%	22%
Capacity Factor (2025)	29%	0%
DAFOR (2024)	0%	9%
DAFOR (2025)	1%	0%
Availability Factor (2024)	0%	60%
Availability Factor (2025)	45%	0%

The Wreck Cove units have been subject to a “Life Extension and Modernization” (“LEM”) project that includes replacing the generating units and refurbishing the turbines, among other work.⁴⁷⁶ In addition, NSPI pursued remediation and restoration of a tunnel integral to the operation of Wreck Cove following rockfall events in the tunnel.⁴⁷⁷ (This latter event is the subject of a separate proceeding, M10632). The LEM work continued during this Audit Period, affecting the units’ performance metrics.

Originally, Unit 1 was forecasted by NSPI to be available for commercial operation in June 2023 and Unit 2 one year later in June 2024. Unit 1 was removed from service in June 2022 and was returned to limited service in August 2024. From August 2024 to January 2025, Unit 1 was intermittently available for generation while post-commissioning work was completed, though the unit was unavailable from September 2024 to November 2024 when the unit was required to be isolated to facilitate main inlet valve removal on Unit 2. Work was completed and final handover of Unit 1 to system operations occurred in January 2025.

Also impacting Unit 1 was the tailrace rock bolting project (CI 0006418 HYD WRC Tailrace Tunnel Rock Bolting Phase 2), which had been planned to be executed in the summer of 2024 following Unit 2’s LEM activities, but was delayed into 2025. NSPI scheduled the Unit 1 tailrace work with the Unit 2 LEM outage. Unit 1 was offline for 100% of all hours in 2024 (all due to planned outage or planned extension of a maintenance outage). In 2025, Unit 1 was available to operate in 45% of all hours, operating in 38% of all hours, and was on some sort of planned or maintenance outage in 55% of all hours.

⁴⁷⁴ Q4 2024 FAM Report, 9(3).

⁴⁷⁵ Q4 2025 FAM Report, 9(3).

⁴⁷⁶ NSUARB, “Decision,” M09596, November 26, 2020.

⁴⁷⁷ NSUARB, “Decision,” M10632, December 18, 2023.

Unit 2 was available for generation while Unit 1 was offline for its LEM activities. Unit 2 was removed from service in September 2024 and was scheduled to be returned to operation in June 2026. Unit 2 was available to operate in 60% of hours in 2024 and actually operated in 34% of hours that year. The unit was on planned or maintenance outages in 37% of all hours in 2024. In 2025, Unit 2 was offline on planned outage for LEM activities in 100% of hours.

NSPI indicated that it sought to manage execution of this work to maintain system capability by ensuring at least one unit was available for generation where feasible, aligning periods requiring reduced availability (including overlapping outages) with lower-demand periods and minimizing spill. NSPI spilled water on seven occasions during the Audit Period, with spill events lasting as little as one day and as much as 22 days. Four events occurred in spring time (one in April 2024, two in April 2025, one in May 2025), totaling 15.1 GWh. Three others occurred in colder months, including a 3-day event in November 2024, a 1-day event in December 2024, and a 22-day event lasting from December 19, 2024 to January 9, 2025, collectively totaling 25.3 GWh.

We reviewed Wreck Cove's Audit Period data for its attempted startups, which suffered challenges in recent periods. The data suggests the LEM work is improving the performance of the units in their attempt to start, which is consistent with the LEM scope, and as many of the failed startups are related to degradation and reliability issues associated with legacy control, protection, instrumentation and other key components, that were addressed during LEM work. Unit 2, which operated during the Audit Period prior to its LEM work, suffered 13 failed starts out of 145 attempts, a failure rate of 9.0%. Unit 1, which operated following completion of its LEM work, experienced just two failed starts out of 49 attempts, a failure rate of 4.1%.

Had NSPI completed the LEM work on Unit 1 and Unit 2 according to the original schedule, FAM customers would have benefited from lower costs during the Audit Period. When requested for the impact of the cost of the delay, NSPI indicated that it had not tracked the cost of delays or outages. Using a rough assumption of annual output of 300 GWh from Wreck Cove,⁴⁷⁸ NSPI could have received an additional 79.0 GWh in 2024 and 35.7 GWh in 2025. Using the "Fuel Cost per MWh-\$/MWh on Total Generation" reported for 2024 (\$■■■■/MWh⁴⁷⁹) and 2025 (\$■■■■/MWh⁴⁸⁰) as rough estimates of cost, these generation volumes total about \$■■■■ in value. Our assumed price for 2024 (\$■■■■/MWh) is likely conservative, given that this price includes the impact of the Federal Loan Guarantee. We acknowledge these are rough estimates, as hydrological conditions can impact the amount of generation that can be produced by hydro units in a given period of time.

⁴⁷⁸ NSPI forecasts 293.3 GWh of Wreck Cove generation in 2026, though LEM work is expected to prevent Unit 2 from rejoining the grid until June 2026. (2025 FAM Annual Report, tab A-10(9).) We round this value up to a potentially conservative value of 300 GWh/year.

⁴⁷⁹ Q4 2024 FAM Report, tab 1(3).

⁴⁸⁰ Q4 2025 FAM Report, tab 1(3).

We understand that capital projects at two other NSPI-owned hydro projects have been subject to delays, including Tuskett Falls and Gaspereau (which is captured in NSPI's Black River hydro generator system). Our understanding is that these are both dam refurbishment projects and that the hydroelectric generators remain operational despite these delays. NSPI claims that because the generators remain in service, there are no FAM cost impacts related to these two dam refurbishment projects as there has been no material loss in generation. We agree with NSPI that the generators continued to produce output during the Audit Period, and it is not evident from output data that Tuskett or Black River were materially impacted by delays in dam refurbishment. In 2024, Black River (-8%) performed better than NSPI's hydro fleet average (-23%) compared to BCF forecast, and while Tuskett (-46%) was below average, it was not the largest underperformer (Sheet Harbour (-48%) was greater).⁴⁸¹ In 2025, Black River (-51%) and Tuskett (-55%) underperformed by greater margins than average in NSPI's fleet (-36%), but were not the largest underperformers (Lequille (-83%) and Avon Hydro (-70%) were greater).⁴⁸²

X.B.4. OM&G Costs

Operating, maintenance, and general ("OM&G") costs are not recoverable through the FAM. Nevertheless, OM&G costs remain worth summarizing here in our discussion of power plant performance. NSPI spent approximately \$194.7 million in OM&G expenses during the Audit Period across its specific generating units, or about \$97.2 million per year. These expenditures do not include other OM&G costs, such as that for common capital spending, which typically exceeds \$25 million/year.⁴⁸³ OM&G expenses during the Audit Period increased by about 8.8 percent over the prior Audit Period, as is shown in **Figure X-25** below.

Figure X-25: OM&G Costs (2015–2025, \$mm)⁴⁸⁴

Plant	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Lingan	\$17.9	\$14.4	\$16.4	\$16.4	\$15.8	\$15.2	\$15.9	\$17.1	\$18.4	\$18.5	\$19.8
Tufts Cove	\$12.2	\$12.5	\$12.1	\$14.6	\$11.4	\$11.4	\$13.4	\$15.6	\$16.2	\$16.7	\$18.2
Pt. Tupper	\$8.1	\$7.7	\$8.0	\$7.8	\$7.9	\$6.8	\$7.5	\$7.8	\$7.8	\$8.4	\$9.5
Pt. Aconi	\$8.5	\$8.0	\$8.1	\$7.8	\$8.1	\$7.9	\$7.6	\$8.2	\$8.5	\$8.6	\$8.9
Trenton	\$14.6	\$13.8	\$14.1	\$13.3	\$14.3	\$11.4	\$11.3	\$12.4	\$12.7	\$13.5	\$14.7
Hydro	\$8.0	\$7.8	\$8.1	\$9.6	\$8.2	\$7.9	\$7.5	\$9.0	\$11.1	\$10.6	\$11.7
Wind	\$6.0	\$8.4	\$8.9	\$8.8	\$9.0	\$8.3	\$8.2	\$8.4	\$8.9	\$9.3	\$9.5
Combustion Turbine	\$1.3	\$3.8	\$1.7	\$1.5	\$1.7	\$1.4	\$1.7	\$2.0	\$2.1	\$2.2	\$2.0
Biomass	\$7.0	\$6.5	\$6.4	\$6.5	\$6.5	\$6.2	\$6.3	\$6.2	\$6.6	\$6.5	\$6.1
Total	\$83.6	\$82.9	\$83.8	\$86.3	\$82.9	\$76.5	\$79.4	\$86.7	\$92.3	\$94.3	\$100.4

Given the different sizes and number of units at each generating plant, we reviewed OM&G costs on a per megawatt basis across each NSPI plant. As is shown in **Figure X-26**, the NSPI fleet averaged \$40,237/MW in average annual OM&G costs during the Audit Period; the Port Hawkesbury biomass

⁴⁸¹ Q4 2024 FAM Report, tab 9(3).

⁴⁸² Q4 2025 FAM Report, tab 9(3).

⁴⁸³ 2020-2021 Bates White Audit Report, page 214.

⁴⁸⁴ 2022-2023 Bates White Audit Report, page 251.

plant (~\$147,000/MW) and NSPI's wind generation (~ \$117,000/MW) were the most expensive units, while the combustion turbines (~ \$9,000/MW) and the hydro units (~ \$30,000/MW) were the least expensive.

Figure X-26: Average Annual OM&G Costs During Audit Period (\$/MW)⁴⁸⁵

Plant	Audit Period Annual Average (\$mm)	Capacity (MW)	Average Annual OM&G Costs per MW
Biomass	\$6.3	43	\$146,826
Wind	\$9.4	81	\$116,660
Pt. Tupper	\$8.9	150	\$59,661
Pt. Aconi	\$8.7	168	\$52,033
Trenton	\$14.1	304	\$46,415
Tufts Cove	\$17.5	462	\$37,781
Lingan	\$19.1	607	\$31,530
Hydro	\$11.2	374	\$29,860
Combustion Turbines	\$2.1	231	\$8,988
Total	\$97.3	2,419	\$40,237

We also reviewed OM&G costs on a \$/MWh basis. As is shown in Figure X-27, NSPI's OM&G costs across all its generators averaged \$13.32/MWh during the Audit Period. Leaving aside the renewable generators and the peaking combustion turbines, the fleetwide thermal average was \$10.98/MWh for the Audit Period, a decrease of about 1 percent from the prior Audit Period total of \$11.07/MWh.⁴⁸⁶

⁴⁸⁵ 2025 Annual FAM Report, A2; **Figure X-26** does not consider common OM&G items, such as plant operations and ERM costs.

⁴⁸⁶ 2022- 2023 Bates White Audit Report, Figure X-26.

Figure X-27: OM&G Costs During Audit Period (\$/MWh)⁴⁸⁷

Plant	OM&G Costs (\$mm)	MWh	OM&G Costs per MWh
Combustion Turbines	\$4.2	35,367	\$117.41
Biomass	\$12.6	346,589	\$36.43
Wind	\$18.8	502,901	\$37.39
Trenton	\$28.2	1,985,466	\$14.21
Hydro	\$22.3	1,279,567	\$17.44
Tufts Cove	\$34.9	4,001,215	\$8.72
Pt. Tupper	\$17.9	1,253,360	\$14.28
Pt. Aconi	\$17.5	1,453,295	\$12.03
Lingan	\$38.3	3,755,264	\$10.19
Total	\$194.7	14,613,022	\$13.32

Historically, labour is the largest portion of OM&G costs, typically averaging just over half of total OM&G spend. In this Audit Period, NSPI spent \$115.5 million on labour, an increase of about 10 percent over the prior Audit Period total of \$104.7 million.⁴⁸⁸ In all, labour made up about 59 percent of OM&G expenses, which was in line with NSPI's expectations⁴⁸⁹ and prior years' results. Looking more closely at labour costs, we noted the continued trend first identified by the previous auditor—i.e., that NSPI appears to regularly overestimate its “regular labour,” which is the scheduled hours of its internal employees, and underestimate the amount of overtime, term, and contract labour needed to make up the difference. For this Audit Period, NSPI's regular labour hours were about 8% below budget for the Audit Period, while overtime labour was 58% above budget and term labour was 54% above budget.

As we noted in prior Audit Reports, NSPI has reduced its internal employees at its thermal plants in recent years⁴⁹⁰ and this data still may suggest an increased reliance on overtime labour when unexpected issues arise at thermal plants that require additional work. As we found, however, in our previous Audit Report, NSPI plans its regular labour based on full availability of its existing labour force—that is, there are no allowances made for parental leave, disability, resignations, or other labour disruptions that were not known at the time of the budgeting process, which would require NSPI to make up for this lost labour with other options, such as overtime, term, or contract labour.

During the Audit Period, full-time employee headcount at NSPI's power plants increased from 596 at the start of the Audit Period to 631, an increase of 5.9 percent. Most notable was the increase in full-time employees at Tufts Cove from 99 to 113 and hydroelectric stations from 79 to 96.

⁴⁸⁷ 2024 Q4 FAM Report, 2(3) and 9(3); 2025 Q4 FAM Report, 2(3) and 9(3); **Figure X-27** does not consider common OM&G items, such as plant operations and ERM costs.

⁴⁸⁸ 2022-2023 Bates White Audit Report, section X.B.4.

⁴⁸⁹ NSPI forecasted labor to make up about 59 percent of OM&G expense.

⁴⁹⁰ See, e.g., 2016-2017 Bates White Audit Report, page 171; 2020-2021 Bates White Audit Report, page 216.

X.B.5. Sustaining Capital

Sustaining capital investments related to NSPI's power plants are not recovered through the FAM. Despite the remainder of the capital investments being recovered through depreciation expense, and not through the FAM, we include a brief overview of these costs, since they are intended to keep the NSPI fleet in sufficient operating condition and are thus part of the sustaining capital associated with NSPI's generation fleet.

Figure X-28 shows that across NSPI's generating fleet, including investment that accrues across the portfolio, NSPI invested \$152.2 million in 2024 and \$146.0 million in 2025.⁴⁹¹ The combined \$298.2 million in sustaining capital during the Audit Period represents a decrease of 13.6 percent, or \$47.1 million, from the prior Audit Period's sustaining capital of \$345.3 million. NSPI continues to use PLEXOS modeling to determine the expected utilization of each asset to help determine what investment is needed, noting too that when major refurbishments arise, NSPI may incur additional sustaining capital costs.

Figure X-28: Sustaining Capital by Plant (2015–2025, \$mm)⁴⁹²

Plant	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Lingan	\$29.3	\$26.0	\$12.2	\$17.1	\$16.1	\$12.8	\$15.6	\$24.4	\$23.1	\$22.5	\$6.4
Tufts Cove	\$6.0	\$11.7	\$14.9	\$12.1	\$12.1	\$7.0	\$12.8	\$23.6	\$26.7	\$23.4	\$15.5
Pt. Tupper	\$9.1	\$4.6	\$6.9	\$4.2	\$15.1	\$3.5	\$5.8	\$6.4	\$6.0	\$10.5	\$4.9
Pt. Aconi	\$9.5	\$11.8	\$17.0	\$14.4	\$14.8	\$12.4	\$12.2	\$15.3	\$11.5	\$19.8	\$21.0
Trenton	\$18.1	\$18.1	\$24.8	\$11.0	\$23.7	\$9.6	\$13.8	\$12.9	\$11.7	\$11.8	\$11.2
Hydro	\$28.6	\$34.9	\$29.8	\$30.2	\$34.3	\$29.9	\$76.5	\$88.8	\$49.1	\$40.2	\$53.3
Combustion Turbines	\$10.6	\$6.7	\$17.9	\$6.5	\$10.1	\$10.3	\$14.8	\$10.9	\$12.2	\$10.8	\$23.6
PH Biomass	\$1.2	\$1.1	\$1.1	\$1.3	\$1.1	\$2.0	\$2.5	\$5.8	\$4.9	\$5.5	\$6.6
Wind	\$17.0	\$0.1	\$0.5	\$0.2	\$0.0	\$1.1	\$3.1	\$5.6	\$2.8	\$1.8	\$1.6
Fuel, Energy, & Risk Management	\$1.4	\$0.9	\$4.3	\$2.1	\$2.5	\$2.0	\$1.5	\$1.5	\$2.1	\$6.0	\$1.9
Total	\$130.8	\$115.9	\$129.4	\$99.2	\$129.9	\$90.5	\$158.6	\$195.2	\$150.1	\$152.2	\$146.0

Figure X-29 shows this same capital investment, by plant, as broken down in dollars per MW. Over the Audit Period, PHB, the hydro units, and Point Aconi stood out as the units that saw the greatest investment per MW, while the Lingan and the wind units saw the least.⁴⁹³ These results can vary considerably over time, as a unit can receive significant investment in a given year for a major maintenance overhaul, while in subsequent years, they may see less investment.

⁴⁹¹ 2024 and 2025 FAM Annual Reports, A7.

⁴⁹² 2022–2023 Bates White Audit Report, page 253; 2024 FAM Annual Report A7; 2025 FAM Annual Report A7.

⁴⁹³ 2024 FAM Annual Report A2, A7; 2025 FAM Annual Report A2, A7.

Figure X-29: Average Annual Capital Investment by Plant (\$/MW)⁴⁹⁴

Plant	Audit Period Annual Average (\$mm)	Capacity (MW)	Annual Capital Investment per MW
PH Biomass	\$6.1	43	\$141,100
Hydro	\$46.8	374	\$125,102
Pt. Aconi	\$20.4	168	\$121,297
Tufts Cove	\$19.4	318	\$61,105
Pt. Tupper	\$7.7	150	\$51,514
Combustion Turbine (Includes LMs)	\$17.2	375	\$45,876
Trenton	\$11.5	304	\$37,804
Lingan	\$14.4	607	\$23,739
Wind	\$1.7	81	\$21,221
Total	\$145.2	2,419	\$60,003

We compared sustaining capital expenditures by selected plants to assumptions made in NSPI's Evergreen IRP modeling to review how actual expenditures compared to what was assumed in the Evergreen IRP. This is shown in Figure X-30 below. Actual 2025 sustaining capital expenditures were materially different than modeled IRP assumptions, with a mix of expenditures that exceeded forecast and others that were less than forecast. The vintage of the IRP assumptions (2022) is likely driving some of the deviations.

Figure X-30: 2025 Sustaining Capital Comparison (\$mm, Actual vs. IRP)⁴⁹⁵

Plant	Evergreen IRP Assumption	Actual	% Increase (Decrease)
Trenton	\$21.5	\$11.2	-48%
Pt. Tupper	\$5.5	\$4.9	-10%
Combustion Turbines (incl. TC 4-6)	\$17.6	\$23.6	34%
Pt. Aconi	\$18.0	\$21.0	17%
Tufts Cove 1-3	\$11.9	\$15.5	30%
Lingan	\$33.8	\$6.4	-81%
Biomass	\$3.3	\$6.6	104%

To get a better sense of NSPI's current expectations for future sustaining capital, we reviewed NSPI's most recent forecast (out to 2050). NSPI is forecasting sustaining capital to *decrease*, with a compound annual growth rate of -3.21%. Of its existing fleet, only the Tufts Cove units (1-6), PHB, and the CTs are forecasted to exist as they do today. The solid fuel fired generators are either retired or converted to non-solid fuel by 2030. Specifically, Trenton 5, Point Aconi, and Lingan 2 are assumed to be retired in 2030,

⁴⁹⁴ 2024 FAM Annual Report A2, A7; 2025 FAM Annual Report A2, A7. **Figure X-29** does not include ERM common spending.

⁴⁹⁵ 2025 FAM Annual Report A7. **Figure X-30** does not include ERM common spending. The Figure's Evergreen IRP assumptions include both fixed and variable components of sustaining capital.

while the other units – Lingan 1, 3, and 4 to HFO, Point Tupper to natural gas, and Trenton 6 to biomass – are considered to be converted.

X.B.6. Power Plant Visits

The FAM POA requires the fuel auditor to “[c]onduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring.” In May 2026, we completed the following in-person site visits: (1) Port Hawkesbury Biomass Plant; (2) Point Tupper Generating Station; (3) Point Tupper Marine Terminal; (4) Bear Head coal storage and ash management site; (5) Trenton Generating Station; and (6) Tufts Cove Generating Station. For the generating stations, each site visit included interviews with plant personnel and tours of the plant (including fuel inventory/infrastructure). For the inventory locations, the site visits included interviews with NSPI personnel and [REDACTED] employees ([REDACTED] is the operator of the Point Tupper Marine Terminal and Bear Head on NSPI’s behalf) and tours of the facilities, assets, and inventories. Our findings related to these plants are included in our discussion of plant-specific issues elsewhere in this (and other) chapters.

X.B.7. Environmental Matters

NSPI is subject to provincial regulations and laws that govern the allowable emissions from its generating facilities. These include both fleetwide limits and unit-specific limitations. NSPI is required to comply with annual emissions limits for its fleet and by generating unit for sulphur dioxide (“SO₂”) and faces fleetwide limits for emissions of nitrous oxide (“NO_x”), mercury (“Hg”), and carbon dioxide (“CO₂”).

Figure X-31 shows NSPI’s fleetwide limitations on SO₂, NO_x, and Hg.

Figure X-31: NSPI’s Fleetwide Emissions Limits under Nova Scotia’s Air Quality Regulations (through 2030)⁴⁹⁶

Compliance Period	SO ₂ (tons)			NO _x (tons)		Mercury (kg)
	Generating Unit Maximum	Annual Fleetwide	Cumulative	Annual Fleetwide	Cumulative	Annual Fleetwide
2021-2022	Compliance period complete				56,000*	Compliance period complete
2023-2024	17,760	-	68,000	-		35
2025	13,720	45,000	-	11,500		35

*56,000 t NO_x in aggregate is the allocation for 2021-2024

⁴⁹⁶ *Air Quality Regulations*, made under sections 25 and 112 of the *Environment Act* S.N.S. 1994-95, c. 1 O.I.C. 005-87 (February 25, 2005, effective March 1, 2005), as amended, Schedule C. The mercury limitation allows NSPI to apply an additional 10 kg of mercury credits in each year, suggesting an effective (net) mercury limit of 45 kg/year. NSPI Response to 2-66 (e).

During the Audit Period, NSPI was subject to two separate, independent regulatory frameworks governing greenhouse gas (“GHG”) emissions. First, NSPI is subject to the province’s *Greenhouse Gas Emissions Regulations*, which applies a fleetwide limit on GHG (or CO₂-equivalent) emissions during specified intervals. Figure X-32 shows NSPI’s applicable limitations related to this regulation.

Figure X-32: NSPI’s Fleetwide CO₂ Equivalent Emissions under Nova Scotia’s Greenhouse Gas Emissions Regulations⁴⁹⁷

Compliance Period	CO ₂ e (mega tons)
2021-2024	27.5 (cumulative total)
2025	6

Second, NSPI was also subject to the Output Based Pricing System (“OBPS”), which became effective starting in 2023 and replaced the Cap-and-Trade program. Unlike the Cap-and-Trade program that was based on reducing total emissions regardless of the source, OBPS sets performance standards for individual generators and fuel types. This allows production and emissions to increase without penalty for facilities that meet or exceed their standards.

Generating units that emit 50,000 tonnes or more of greenhouse gas emissions must participate in OBPS.⁴⁹⁸ Generating units that emit between 10,000 and 50,000 tonnes are eligible to apply to the Minister of Environment and Climate Change to voluntarily opt-in.⁴⁹⁹ NSPI received approval to opt-in PHB and Burnside starting in 2023. All units at Lingan, Point Aconi, Point Tupper, Trenton and Tufts Cove are obligated to participate.

OBPS operates around a set of performance standards defined by Nova Scotia. A performance standard is an emissions rate (tonnes/MWh) based on fuel type: solid fuels, liquid fuels, existing gas, and new gas.⁵⁰⁰ The performance standard for solid fuels, set by Nova Scotia at 925 tonnes/GWh in 2024 and 2025, is less than the Federal standard of 538 tonnes/GWh in 2024 and 510 tonnes/GWh in 2025.⁵⁰¹ Performance standards for solid fuels and new gas (but not liquid fuels or existing gas), are set to become more restrictive over time. Nova Scotia’s standard for solid fuels is set to reach the Federal standard in 2030.⁵⁰²

Nova Scotia grants “performance credits” to NSPI for generators that exceed their performance standard (the emissions rate is less than the performance standard rate). One credit is equal to one tonne

⁴⁹⁷ *Greenhouse Gas Emissions Regulations*, made under subsection 28(6) and Section 112 of the *Environment Act*, S.N.S. 1994-95, c. 1, O.I.C. 2009-341 (August 14, 2009), N.S. Reg. 260/2009, as amended. NSPI Response to 2-66 (e).

⁴⁹⁸ An individual generator can have more than one fuel type.

⁴⁹⁹ See “Output-Based Pricing System Registration and Opt-in Regulations” under Section 112ZJ of the *Environment Act*, made effective January 1, 2023, available at: <https://novascotia.ca/just/regulations/regs/envoutput.htm>

⁵⁰⁰ NSPI, “OBPS Compliance Update,” April 5, 2024, slide 3.

⁵⁰¹ NSPI, “OBPS Compliance Update,” April 5, 2024, slide 3.

⁵⁰² NSPI, “OBPS Compliance Update,” April 5, 2024, slide 3.

of reduced GHG emissions. NSPI accumulates “fund credits” (obligations), also equal to one tonne of emissions, when a generator falls short of the performance standard (the emissions rate is greater than the performance standard rate). Performance credits are offset against fund credits at the end of the year and NSPI is obligated to pay for any net positive fund credits (emissions above the performance standard) after review and approval. Performance credits need not be applied in the year they are granted but can be banked for future use, though it has been NSPI’s practice to redeem credits as they are awarded. The price of fund/performance credits follows the federal government’s backstop carbon price. In 2024, the credit price was \$80/tonne. In 2025, the price was \$95/tonne. On May 15, 2026, the federal government updated the headline price trajectory for all industrial carbon pricing systems in Canada. The new guidelines stipulate a credit price of \$100/tonne in each year from 2027 through 2029, followed by a hike to \$115/tonne in 2030.⁵⁰³

NSPI’s OBPS obligations are limited to its owned generators, not third-party generation that serves NSPI customers. As such, output from facilities such as the Brooklyn Energy Facility do not generate OBPS obligations or credits for NSPI’s customers. Imported energy is considered zero emissions for the purpose of air emissions regulations compliance, including OBPS, regardless of source or jurisdiction.

To summarize, the OBPS requires each NSPI generator to meet a performance standard based on its fuel type. The standard will equate to a total amount of emissions over the course of a year – a standard-defined amount of emissions. The actual amount of annual emissions is tracked for each generator and compared to the standard-defined amount. Emissions in excess of the standard-defined amounts accrue fund credits (obligations) and emissions less than standard-defined amount are granted performance credits. Netting together fund and performance credits results in a net amount of emissions. If the net amount is above the standard-defined amount, then NSPI must pay for the cost of those emissions at the credit price, or if the amount is below the standard-defined amount, it will receive the credit value.

NSPI must also ensure that its thermal generating stations’ stack emissions meet certain opacity requirements, ensuring that opacity is maintained at or below 20 percent. Exceptions exist, such as the allowance for visible emissions to increase in opacity to 40 percent for a maximum of six minutes in the hour following any increase in opacity above 20 percent. The generating units also have an exemption from opacity requirements during start-up, shut-down, and during routine maintenance on boilers and associated pollution control equipment. NSPI is also subject to in-stack emissions limits on particulate matter for its thermal generators.

NSPI is also required to supply its customers with electricity generated from at least 40 percent renewable sources each year.⁵⁰⁴ NSPI receives renewable energy from its owned renewable facilities, including its wind and hydro resources, plus PHB, as well as third-party renewable generators, including

⁵⁰³ See Carbon Pricing Systems across Canada, available at <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html>.

⁵⁰⁴ *Renewable Electricity Regulations*, made under Section 5 of the *Electricity Act* S.N.S. 2004, c. 25 O.I.C 2010-381 (October 12, 2010), N.S. Reg. 155/2010 as amended to O.I.C. 2017-187 (July 17, 2017), N.S. Reg. 108/2017, section 6.

third-party wind, COMFIT, and solar resources, as well as the Brooklyn Energy Facility. NS Block volumes count toward RES compliance, as does Surplus Energy if NSPI chooses to purchase Renewable Energy Certificates (“RECs”) associated with the Surplus Energy.

To maintain compliance with emissions limitations, NSPI manages its procurement and use of fuels. At solid fuel-generating stations, this is done through the blending of fuels with appropriate sulphur and mercury content to meet emissions limits. NSPI’s generators are fitted with emissions control equipment that reduce emissions prior to release into the atmosphere. NSPI operates low NO_x burners at Point Tupper, Trenton 6, and the four Lingan units to manage NO_x emissions. All solid fuel plants (other than Point Aconi) are also equipped with electrostatic precipitators to control particulate matter emissions; Point Aconi uses a baghouse to control particulate matter emissions, while Trenton 5 has both a baghouse and electrostatic precipitator. NSPI also uses powder-activated carbon at Lingan, Point Tupper, and Trenton 5 and 6 to manage mercury emissions through the continued operation of sorbent injection system at these units.

NSPI monitors its emissions both in real-time and on an ongoing, cumulative basis. Plants are equipped with real-time emissions monitoring systems. The systems clearly display current conditions and are designed to inform operations personnel if current emissions are approaching limits. NSPI tracks emissions daily, especially for SO₂ and mercury, which have historically been the most challenging emissions limits to meet and were again in this Audit Period. NSPI may also use a compliance “buffer” for emissions to better ensure emissions compliance. During the Audit Period, NSPI used compliance buffers for SO₂.

Each generating facility also is required to operate within the parameters of an Industrial Operating Approval, which contains environmental monitoring and reporting requirements for wastewater, groundwater, surface water, solid waste handling (e.g., ash), and noise.

X.B.7.a. NSPI’s Compliance with Sulfur Dioxide, Nitrous Oxide, and Mercury Emissions Caps

NSPI complied with all fleetwide SO₂ and NO_x limits during the Audit Period. Regarding SO₂, NSPI was assisted by the receipt of the CoV for 2025, which increased the allowed emissions for the year from 28,000 tonnes to 45,000 tonnes. Regarding mercury emissions, NSPI emitted more than the annual limit (35 kg) in both 2024 and 2025. In both years, NSPI could apply 10 kg of credits, effectively raising the annual compliance limit to 45 kg. NSPI’s actual mercury emissions in 2024 were 35.9 kg, below the credit-adjusted cap of 45 kg. In 2025, NSPI emitted 46.9 kg, above the cap of 45 kg. These results are shown in Figure X-33 below.

Figure X-33: NSPI's Compliance Status with SO₂, NO_x Emissions vs. Caps (2024-2025)

Limit	Compliance Period	Actual Emissions	Emissions Limit	Exceedance (%)
SO ₂ (tonnes)	2023-2024	66,909	68,000	-
SO ₂ (tonnes)	2025	44,268	45,000*	-
NO _x (tonnes)	2021-2024	45,495	56,000	-
NO _x (tonnes)	2025	11,267	11,500	-
Hg (kg)	2024	35.9	35	3%
Hg (kg)**	2025	46.9	35	34%

*NSPI received an SO₂ CoV, increasing its 2025 limit from 28,000 to 45,000 tonnes

**10 kg of credits can be applied annually for an effective limit of 45kg

NSPI reported in its 2025 FAM Annual Report that its actual mercury emissions in 2025 was 45.0 kg, though were due to be “finalized and third-party verified by March 31, 2026 as per Provincial reporting requirements.”⁵⁰⁵ During our audit review of this issue, NSPI noted that its “Mercury Monitoring Protocol” states that “[f]or reporting purposes, NSPI will apply a conservative accuracy of +/- 5% to annual emissions.” That is, “[e]ach year when NSPI reports the annual mass of mercury, the accuracy of the total will be considered and if the number is within 5% of the annual compliance limit, then the lower number will be reported.” Accordingly, NSPI’s reporting in the 2025 FAM Annual Report indicated a 2025 mercury emissions of 45.0 kg (not 46.9 kg) and indicated no violation of its annual limit in 2025.

X.B.7.b. NSPI's Greenhouse Gas Emissions Results

As explained above, NSPI is subject to two separate, independent regulatory frameworks governing GHG emissions. NSPI’s compliance period for the province’s *Greenhouse Gas Emissions Regulations* covered two periods: 2021-2024 and 2025. For 2021-2024, NSPI entered the Audit Period having emitted approximately 16.8 mega tonnes of CO₂ equivalent, which left NSPI up to 10.7 mega tonnes of CO₂ equivalent emissions in 2024 to meet the cap of 27.5 mega tonnes over the 2021 to 2024 period.⁵⁰⁶ NSPI’s actual 2024 GHG emissions totaled just 5.6 mega tonnes, keeping NSPI in compliance for the 2021-2024 period. NSPI was also in compliance for the 2025 period, emitting 5.8 mega tonnes of GHG, just under the cap of 6 mega tonnes for the year. Going forward, this requirement will become more restrictive: NSPI’s 2026-2029 compliance period allows NSPI to emit just 21.5 mega tonnes of GHGs, which is equivalent to about 5.4 mega tonnes per year.⁵⁰⁷ Again, NSPI emitted more than 5.4 mega tonnes in both 2024 and 2025.

Regarding the OBPS program, compliance is not an either/or scenario: NSPI can emit any amount of GHGs so long as it pays the province the cost of the GHG emissions under the OBPS rules. The OBPS

⁵⁰⁵ NSPI 2025 FAM Annual Report, tab A13a.

⁵⁰⁶ 2022-2023 Bates White Audit Report, page 260.

⁵⁰⁷ 2022-2023 Bates White Audit Report, Figure X-31.

program applies different levels of allowed emissions intensities – measured in tonnes/GWh – depending on the fuel type. As is shown in Figure X-34 below, gas-fired units have the lowest allowed intensity in 2024 and 2025, while solid fuel-fired units have the highest. Over time, that changes, with solid fuel-fired units becoming subject to more strict intensity limits, while others (existing gas, liquid fuels) remain the same. The 2024 cost of GHG emissions was \$80/tonne, which, as of May 2026, will reach \$115/tonne in 2030.⁵⁰⁸

Figure X-34: OBPS Allowed Intensities (tonne/GWh) and Cost of GHG (\$/tonne) (2023-2030)⁵⁰⁹

Fuel Type	2023	2024	2025	2026	2027	2028	2029	2030
Solid Fuels	925	925	925	925	900	850	650	370
Liquid Fuels	550	550	550	550	550	550	550	550
Existing Gas	370	370	370	370	370	370	370	370
New Gas	370	247	206	164	123	82	41	0
Cost of GHG Emissions (\$/tonne)	\$65	\$80	\$95	\$110	\$125	\$140	\$155	\$170

During the Audit Period, NSPI's GHG emissions were 11.4 mega tonnes. NSPI's total GHG compliance costs were \$42.3 million during the Audit Period.⁵¹⁰ NSPI's estimates for the cost (or credits) generated by each of its relevant generating units is found in Figure X-35 below. Note that the total compliance cost (\$40.9 million) differs from the \$42.3 million reported by NSPI in its FAM reporting. We include a recommendation that NSPI reconcile this difference. The figure shows that PHB generated approximately \$24.5 million in OBPS credits, with Trenton (\$6.0 million) and Lingan (\$1.4 million) also generating credits during the Audit Period. Tufts Cove generated by far the largest GHG compliance cost of \$54.9 million.

Figure X-35: NSPI's Estimated OBPS Cost, by Generating Unit (2025)

Generator	2024 (\$)	2025 (\$)	Total (\$)
Lingan	\$6,280,771	(\$7,673,652)	(\$1,392,880)
Point Aconi	\$3,861,738	\$5,116,191	\$8,977,929
Point Tupper	\$2,745,883	\$4,988,077	\$7,733,960
Trenton	(\$1,550,558)	(\$4,416,339)	(\$5,966,897)
PHB	(\$9,183,246)	(\$15,296,330)	(\$24,479,575)
Tufts Cove	\$29,798,781	\$25,093,876	\$54,892,657
Burnside	\$431,628	\$715,663	\$1,147,292
Total	\$32,384,998	\$8,527,487	\$40,912,485

⁵⁰⁸ See Carbon Pricing Systems across Canada, available at <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html>.

⁵⁰⁹ NSPI, "2026 Q1 Emissions Trends Update," March 27, 2026, slide 3. On May 15, 2026, the federal government updated the headline price trajectory for all industrial carbon pricing systems in Canada. The new guidelines stipulate a credit price of \$95/tonne in 2026, \$100/tonne in each year from 2027 through 2029, and \$115/tonne in 2030.

⁵¹⁰ NSPI Q4 2025 Report, tab 1(3).

A final note on OBPS compliance relates to the Burnside units, which NSPI voluntarily registered in the OBPS program in 2023. NSPI reasoned at the time that it was more cost effective to pay GHG OBPS costs for emissions from the unit than to pay the GHG tax applied to fuel, which it would no longer have to pay if registered as an OBPS resource. Burnside remained in the OBPS program throughout 2024 and into 2025, generating an OBPS compliance cost of about \$1.1 million. However, according to NSPI, in the second quarter of 2025, the federal government removed GHG taxes from diesel, and once completed, NSPI de-registered Burnside from the OBPS program, avoiding both OBPS compliance costs and GHG fuel taxes for the unit.

X.B.7.c. NSPI's Compliance with Opacity and Stack Limitations

As shown in Figure X-36 below, NSPI exceeded opacity limits at its generating stations 120 times during the Audit Period, up from 52 in the prior Audit Period.⁵¹¹ Most of those exceedances were observed at Lingan (65). There were also two instances when a generating unit failed to comply with in-stack particulate limits, both at Trenton 5 in 2024. The first was demonstrated in February 2024 following third-party testing. Nova Scotia Environment and Climate Change requested a follow-up test, which was completed in September 2024 and which again showed an exceedance of the limit. To address these results, NSPI completed maintenance on its electrostatic precipitator and baghouse, which in part is meant to control particulate matter emissions, and reported no additional exceedances the rest of the Audit Period.

Figure X-36: Opacity Exceedances, by NSPI Generator

Unit	2024 Exceedances	2025 Exceedances	Total Exceedances
Lingan	33	32	65
Point Tupper	3	2	5
Point Hawkesbury	35	15	50
Total	71	49	120

X.B.7.d. NSPI's Compliance with Renewable Energy Standards

NSPI met its RES compliance requirements in both 2024 and 2025. NSPI received renewable energy equal to 40.5 percent and 40.2 percent of its net electricity sales in 2024 and 2025, respectively, exceeding the RES requirement of 40 percent. Audit Period data is shown in Figure X-37 below.

Figure X-37: NSPI's RES Compliance by Year (2024-2025)

	2024	2025	Total 2024-2025
Sales (net of losses) (GWh)	10,581	10,705	21,286
Renewable energy (GWh)	4,286	4,302	8,588
RES Percentage	40.5%	40.2%	40.3%

⁵¹¹ 2022-2023 Bates White Audit Report, page 262.

IPP and COMFIT purchases (36.7%) and NS Block volumes including make-up volumes (29.3%) made up the majority of NSPI's RES-compliant supply. NSPI's resources also contributed, including hydro (14.9%), wind (5.9%), and PHB (3.7%). Imported energy made up 6.7% of all RES-compliant supply received and was primarily comprised of Surplus Energy from Newfoundland for which NSPI opted to purchase the associated renewable energy credits. Under the Energy Access Agreement, Surplus Energy is delivered without environmental attributes (i.e., RECs), but NSPI can bilaterally purchase those RECs separately from Newfoundland and Labrador Hydro. During the Audit Period, NSPI purchased the RECs associated with 155 GWh in 2024 (at \$2.00/REC) and 275 GWh in 2025 (at \$2.25/REC). This is a notable development, as NSPI can use purchase of RECs associated with Surplus Energy as a source of additional RES-compliant generation supply when other sources are insufficient to meet compliance targets. As such, we would expect NSPI to purchase few, if any, RECs from Newfoundland in years in which it receives surplus volumes of RES-compliant supply from its other sources. In the case of 2024 and 2025, NSPI's REC purchases were needed: absent them, NSPI would have not met its RES compliance targets in either year (39.0% in 2024 and 37.6% in 2025).

X.B.8. Bates White's 2022-2023 Audit Recommendations

In our report for the prior Audit Period, we included seven recommendations regarding power plant performance. We address each as follows.

Our first recommendation related to power plant performance was:

Recommendation IX-1: NSPI should address the identified discrepancy in reporting of forced outages and derates and revise its outage/derate tracking and reporting, as appropriate.

We address this recommendation in section X.B.2.a.iv above, where we found that NSPI fully addressed this recommendation.

Our second recommendation related to power plant performance addressed performance test results at Tufts Cove 2 during the prior audit period, which showed that Tufts Cove 2's maximum output capability as tested was more than 2% below its rated capacity.⁵¹² Our related recommendation was:

Recommendation X-2: NSPI should explain and address any implications associated with Tufts Cove 2's consecutive maximum real power test results.

NSPI accepted this recommendation. NSPI explained that there were no regulatory implications related to the prior test results, noting that the relevant NERC standard (NERC MOD-025-2) would require a retest if a condition was identified that changed the real power value of the unit by more than 10% from its previous test. NSPI also conducted a test of Tufts Cove 2 in January 2024, which showed

⁵¹² 2022-2023 Bates White Audit Report, Conclusion X-13.

the unit's gross and net real power was within 2% of its rated values, which is an improvement from the prior audit period's test results. We consider NSPI to have fully responded to our recommendation.

Our third recommendation related to power plant performance was:

Recommendation X-3: NSPI should complete the further performance tests on the PHB biomass unit using biomass fuel only and testing different biomass fuel moisture contents and PHP loading levels.

NSPI accepted this recommendation. Over the period August 2024 through September 2024, following PHB's summer outage, NSPI tested the unit across all nine PHP operating modes, or OM, with boiler steam flows of 60 kg/s, 50 kg/s, and 40 kg/s⁵¹³ and using lower moisture biomass fuel. NSPI used a fuel blend that was 90% biomass fuel and 10% natural gas, which NSPI described as necessary to "maintain steady steam flow for turbine performance evaluation."⁵¹⁴ The results demonstrated that both steam flow and PHP's OM significantly impacts the amount of output NSPI can achieve from PHB. The figure below demonstrates that at lower steam production, PHB's potential generation is limited. For example, at 60 kg/s of steam, the generator can produce between 36 MW and 46 MW, but at 40 kg/s of steam, the generator produces between 19 MW and 28 MW.⁵¹⁵ The figure also shows that at different PHP OM, the generator's maximum capability is substantially impacted. For example, regardless of steam output, the ability of the generator to produce electricity varies by 10 to 12 MWs at all times, depending on PHP's OM.⁵¹⁶ Generally, the higher the OM, the greater the output NSPI can achieve from PHB,⁵¹⁷ which is the result of PHP's industrial process specifics.⁵¹⁸

Figure X-37: PHB Steam Turbine Performance (in MW) Across Different Steam Production, PHP OM Scenarios.⁵¹⁹

PB3 Average Steam Flow (kg/s)	PHP OM Mode Range	Steam Turbine Output Range (MW Gross)
60	1 - 9	36 - 40
50	1 - 9	28 - 40
40	1 - 9	19 - 28

To further test PHB at multiple fuel moisture levels, NSPI conducted further testing from September 2024 through February 2025, which allowed for testing of moisture fuel blends of 50%, 55%, and 60%.⁵²⁰ This time, NSPI's tests used 100% biomass fuel.⁵²¹ The results showed that increases in biomass fuel

⁵¹³ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slides 4, 8.

⁵¹⁴ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 4.

⁵¹⁵ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 8.

⁵¹⁶ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 8.

⁵¹⁷ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 7.

⁵¹⁸ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 5.

⁵¹⁹ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 8.

⁵²⁰ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 10.

⁵²¹ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 10.

moisture significantly impacts operation and performance of PHB, including: (1) biomass fuel useful energy declines significantly with increasing moisture content; (2) higher fuel feed rates are needed to produce the same fuel energy inputs to the boiler; (3) boiler efficiency is reduced; (4) introduction of additional stress on certain components (e.g., the induced draft fan) due to the higher weight and volume of the flue gas; and (5) decreased performance of the electrostatic precipitator, increasing the risk of opacity derates.⁵²² The figure below shows the results of the tests, which demonstrate how higher moisture content fuel harms the ability of the boiler to generate steam. As moisture content increases from 50.38% to 55%, steam flow output reduces by almost 25%.⁵²³

Figure X-38: PHB Boiler Steam Flow Across Different Fuel Moisture Content.⁵²⁴

Test Date	Moisture Target (%)	Actual Avg Steam Flow (kg/s)
2024-09-25	50.38	55.6
2025-01-30	55	42
2025-02-04	60	38

These are insightful results that finally achieve what we began recommending two audit periods ago.⁵²⁵ As an initial matter, NSPI has fully addressed our recommendation. NSPI concluded from these results that the unit successfully demonstrated its ability to maintain steam supply across a range of operating conditions and fuel moisture content and presented these findings to the FAM SWG in September 2025.⁵²⁶ We agree. We also note that the results underscore the challenges NSPI faces in predicting the output of this unit, its sensitivity to fuel moisture content (which is in many ways outside NSPI's control), and the challenges in committing and dispatching the unit in an economic manner, since so much depends on PHP's OMs (which are also outside NSPI's control and subject to change).

One additional data point we would wish to highlight is the unit's ability to produce generation on biomass fuel alone. The tests show that if it is able to achieve a moisture content of 50.38%, the unit can produce 55.6 kg/s of steam.⁵²⁷ The tests also show that at 50 kg/s of steam, the unit can produce up to 40 MW (gross) of electricity, while at 60 kg/s of steam, the unit can produce up to 46 MW (gross) of electricity.⁵²⁸ The midpoint of these data – 55 kg/s of steam and 43 MW of electricity – do not support PHB's current nameplate rating of 48 MW, at least insofar as the unit can achieve these values on biomass fuel alone. At 55% average moisture, the unit produces just 42 kg/s;⁵²⁹ at 40 kg/s of steam, the

⁵²² NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 11.

⁵²³ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 12.

⁵²⁴ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 12.

⁵²⁵ 2020-2021 Bates White Audit Report, Recommendation IX-4.

⁵²⁶ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 13.

⁵²⁷ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 12.

⁵²⁸ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 8.

⁵²⁹ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 12.

unit can produce a maximum of 28 MW.⁵³⁰ A further and separate real power test of PHB conducted in December 2025 showed a maximum gross real power of 46.8 MW, with a net real power of 40.3 MW (below its NPCC declared value of 43.0 MW), though that test included use of natural gas (with steam pressure reaching 58.9 kg/s). We do not include any further recommendations on this topic now that NSPI's performance testing has allowed for a more complete understanding of PHB's capabilities and limitations.

Our fourth recommendation related to power plant performance was:

Recommendation X-4: NSPI should provide the Board an update on the status of the remaining 36 recommendations from the Root Cause Analyses at the end of 2024.

NSPI accepted this recommendation and provided the Board an update on December 19, 2024 in which it explained that of all recommendations from the root cause analyses reviewed in the prior audit period, all but 27 had been completed.⁵³¹ NSPI explained that for the remaining 27 recommendations, all were in progress.⁵³² We found NSPI's response to this recommendation positive and satisfactory.⁵³³ It is not our intent to recommend that NSPI provide details for how each recommendation stemming from a root cause analysis be addressed and implemented, and we have observed evidence that NSPI takes its root cause analysis process seriously and attempts to incorporate lessons learned to improve outcomes going forward. This should be a matter of standard course for an electric utility, and we would expect to see NSPI continue to use its root cause analysis process to improve its operations. As such, we include no further recommendations on this point and find NSPI to have fully addressed this recommendation.

Our fifth recommendation related to power plant performance was:

Recommendation X-5: NSPI should make available all Root Cause Analyses that remain in progress as of the end of the 2022-2023 Audit Period in the next FAM Audit.

NSPI accepted this recommendation and committed to provide all such Root Cause Analyses available in the next FAM Audit. NSPI did so, and we discussed the Root Cause Analyses in section X.B.3 above. We therefore consider this recommendation to have been fully addressed.

Our sixth recommendation related to power plant performance was:

Recommendation X-6: NSPI should incorporate reporting of wind curtailment in its FAM reporting.

⁵³⁰ NSPI, "Port Hawkesbury Biomass Plant 2024-2025 Biomass Performance Testing Results," September 26, 2025, slide 8.

⁵³¹ NSPI, "M11533 – 2022-2023 FAM Audit Action Plan Update – Recommendation X-4," December 19, 2024.

⁵³² NSPI, "M11533 – 2022-2023 FAM Audit Action Plan Update – Recommendation X-4," December 19, 2024.

⁵³³ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 7 line 9.

NSPI accepted this recommendation and noted that it would “develop a process for reporting wind curtailments that will be included” in its FAM Annual Report.⁵³⁴ In responsive evidence, the Consumer Advocate witness John Wilson recommended that reporting of curtailment data be done more frequently (e.g., monthly), by (1) including monthly curtailment data in the FAM Annual Report and (2) providing a “reasonable estimate” of monthly curtailments in monthly FAM reports.⁵³⁵ In our Rebuttal Evidence, we noted that our primary concern is that “NSPI begin reporting data on wind curtailment,” and that NSPI’s commitment to do so is positive.⁵³⁶ We noted that we believed Mr. Wilson’s particular recommendation was a reasonable approach to wind curtailment reporting,⁵³⁷ and we noted that in some jurisdictions, wind curtailment data is reported on an hourly basis, a level of granularity NSPI should strive to achieve over time.⁵³⁸

NSPI has introduced wind curtailment data reporting into the FAM Annual Reports. NSPI includes key data, including (1) total wind generation by NSPI-owned or partially-owned generators, (2) total wind generation by third-party generators, (3) total wind generation, (4) total estimated wind curtailments (across all units), and (5) total wind curtailments as a percentage of total wind generation.⁵³⁹ This data is provided by month.⁵⁴⁰ In March 2026, NSPI explained that it was in the process of finalizing the process associated with the calculation of monthly wind curtailment estimates, which would allow NSPI to provide monthly data in its monthly FAM reports. NSPI indicated that it expected to begin providing these monthly updates in “Q2 2026” and would then work with the SWG to refine the reporting format. NSPI began reporting wind curtailment data in FAM monthly reports in April 2026.⁵⁴¹ We expect NSPI will continue to listen to SWG stakeholders in ensuring that reported data is useful. We consider this recommendation to have been fully addressed.

Our seventh recommendation related to power plant performance came in response to our findings related to a damages claim by NSPI against one of its vendors following an extended deration of the South Canoe wind farm. We concluded, in relevant part:

South Canoe, however, was derated during the Audit Period due to defective ladders/lift systems at its turbines that prevented necessary maintenance from being completed. NSPI has pursued damages from the offending vendor (Nordex USA, Inc.) and has recovered some damages already (\$587,503.61). NSPI (and its co-owner of South Canoe) continue to pursue additional damages under the warranty agreement with Nordex. We were not provided the contract with Nordex and thus did not assess the specifics of the damages clause or the claim. Nevertheless, the damages associated with this event could be substantial and NSPI should continue to pursue

⁵³⁴ NSPI Reply Evidence, M11533, September 13, 2024, page 35 lines 7 to 8.

⁵³⁵ Consumer Advocate Evidence, M11533, December 13, 2024, page 11 lines 13 to 14, 18 to 19.

⁵³⁶ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 17 lines 19 to 21.

⁵³⁷ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 18 lines 4 to 6.

⁵³⁸ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 18 lines 11 to 15.

⁵³⁹ See, for example, 2025 FAM Annual Report, tab A15.

⁵⁴⁰ See, for example, 2025 FAM Annual Report, tab A15.

⁵⁴¹ April 2026 FAM Monthly Report, tab M-10.

damages to the maximum extent under its agreement with Nordex and update the Board on the outcome of those efforts, including on the capability status of South Canoe. We requested, but did not receive, hourly capability of all wind resources during the Audit Period. We noted, however, that during the Audit Period, the highest hourly output achieved by South Canoe was 90.9 MW, about 11 percent below its nameplate capacity of 102 MW.⁵⁴²

Our recommendation specifically stated:

Recommendation X-7: NSPI should continue to pursue damages to the maximum extent under its agreement with Nordex and update the Board on the outcome of those efforts, including on the capability status of South Canoe.

NSPI accepted this recommendation. In our Rebuttal Evidence, we noted the Consumer Advocate witness's recommendations on this point, and stated that "NSPI should ultimately demonstrate the outcome of its efforts and provide sufficient support to those reviewing and assessing it, regardless of the forum in which that process occurs."⁵⁴³

NSPI explained that along with the majority owner of the South Canoe project (South Canoe Development Partnership), NSPI brought a claim against Nordex, which culminated in a mediation that occurred in August 2025. The parties achieved a settlement following mediation. NSPI also indicated that at the end of the Audit Period, 29 of the 34 South Canoe turbines were available, with the remaining turbines expected to be available in the first quarter of 2026. NSPI later provided an update that by April 10, 2026, 33 of 34 turbines were available.

As a refresher on the timeline, NSPI owns 49% of the project while South Canoe Development Partnership owns 51%. Nordex is the original equipment manufacturer and is responsible for the design, supply, and warranty of turbine components. Nordex is also the contract operations and maintenance service provider responsible for all maintenance activities. Oxford Frozen Foods Ltd. ("OFF") is retained by NSPI and South Canoe Development Partnership to act as project manager on behalf of the two owners. OFF's responsibilities include managing construction of the project (completed), administering the project's material contracts (including that with Nordex), and managing O&M of the project facilities, among others. NSPI explained that its role in the project and this matter was in its capacity as a minority project owner, providing oversight and working with OFF to ensure that appropriate corrective actions were being taken by Nordex to restore the turbines to full service.

To restore South Canoe to full service, all lift and ladder systems across all 34 turbines required inspection, removal, and replacement. Nordex completed this work, beginning with implementation planning in January 2024 and physical execution, which took place from September 2024 through March

⁵⁴² 2022-2023 Bates White Audit Report, Conclusion X-26.

⁵⁴³ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 22 lines 12 to 20.

2026. All inspection, repair, and replacement work was fully covered under the warranty with Nordex, and NSPI did not incur any direct repair or capital costs associated with these remediation actions.

NSPI and South Canoe Development Partnership sought to recover damages from Nordex for breaches of contract and related negligence pursuant to a Warranty Agreement and an Operations and Maintenance Services Agreement (“O&M Agreement”). NSPI and South Canoe Development Partnership provided an arbitration notice to Nordex advising that the parties were commencing litigation on March 28, 2024 with their statement of position and basis of claims for the June 1, 2022 through May 31, 2023 period⁵⁴⁴ delivered August 9, 2024.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

⁵⁴⁴ 2022-2023 Bates White Audit Report, page 250.

[REDACTED]

NSPI's internal estimate of replacement energy volume is [REDACTED] MWh. We conducted a rough, independent estimate for comparison. To do so, we reviewed South Canoe's output during these periods and compared them against NSPI's BCF forecast output for South Canoe, with one adjustment. To account for the variability of the wind itself, we adjusted the BCF forecasts by observed differences between actual and forecasted output of NSPI's other owned wind generators. [REDACTED]

[REDACTED]

NSPI's cost of replacement energy was about [REDACTED] million. [REDACTED]

[REDACTED]

[REDACTED]. Applying \$ [REDACTED] /MWh as a rough estimate of the costs FAM customers face results in a replacement cost of about \$ [REDACTED] million. [REDACTED]

NSPI's estimate of the cost of replacement RECs is based on the purchase of 123 GWh of RECs, which at a total cost of [REDACTED] [REDACTED] These are reasonable cost assumptions.

[REDACTED]

⁵⁴⁵ NSPI Q2 2025 FAM Report, tabs 9(3) and 10(3).

[REDACTED]

[REDACTED]

[REDACTED] NSPI engaged third-party assistance in developing its damages estimate, a reasonable approach. We find that NSPI has been fully responsive to this recommendation, though its original estimation of the damages associated with the South Canoe outages understated the true cost of replacement energy.

X.C. Conclusions

Conclusion X-1: NSPI's resource portfolio is a mix of wind, hydro, and thermal generating assets. As currently constituted, NSPI's portfolio is not optimal for providing the necessary operational characteristics to balance the high degree of wind on its system.

Conclusion X-2: The impact of the high wind penetration has been that NSPI's thermal units have been displaced as high-capacity factor, baseload resources and have instead forced these units to become low-capacity factor, cycling units, which is not their intended design. In the short run, this leads to lower-capacity factors and loading levels. In the longer run, this can lead to increased degradation of these units over time.

Conclusion X-3: NSPI's thermal generating units' continuing trend of lowered capacity factors persisted during the Audit Period, with most units seeing capacity factors of less than 50 percent during the Audit Period. The aggregate capacity factor for the thermal fleet in 2024 (41 percent) and 2025 (43 percent) remained low but slightly higher than those observed in the prior audit period.

Conclusion X-4: NSPI's thermal fleet largely enjoyed Availability Factors that exceeded industry averages and widely posted better-than-industry-average DAFORs during the Audit Period.

Conclusion X-5: Across NSPI's thermal generating units, total outage hours increased by 3.0 percent from the prior Audit Period, though forced outage hours decreased by 22.7 percent.

Conclusion X-6: Trenton 5 led the fleet in forced outage hours (2,846), more than three times higher than the next closest generator (Point Aconi, 860 hours).

Conclusion X-7: The number of instances where NSPI's thermal generating units were derated decreased 19 percent from the prior audit period, though the size of the average derate increased by 8 MW (or 11.8%), as did the average duration of the derates (by 59 hours, or by 88.2%).

Conclusion X-8: Heat rate performance was mixed, with just one generator beating industry averages in 2024, but improved in 2025 (with five of eight coal-fired units beating industry averages) thanks in part to higher capacity factor operation.

Conclusion X-9: One of NSPI's most internally informative power plant performance metrics is Utilization Factor, which is a metric that captures the "wear" on its generating units driven by capacity factors, cycling, operating hours, flexible use, or some combination of these. Most of NSPI's thermal fleet had Utilization Factors during the Audit Period that were both high and higher than forecast. Higher Utilization Factors can mean higher sustaining capital investments and O&M costs.

Conclusion X-10: NSPI continues to consider economics in determining the optimal length to keep a unit on planned outage. NSPI has provided clear evidence of this in practice in some cases, such as avoiding any planned outages during the winter months.

Conclusion X-11: NSPI's asset management approach remains robust, appropriately uses root cause analysis in addressing outages, and provides solid structure and standardization in tracking, assessing, and seeking to improve generator performance.

Conclusion X-12: Tufts Cove 2 and 3, the only units in the fleet that can burn both natural gas and HFO, had a combined 42 successful fuel switches and zero reported failed fuel switches during the Audit Period. These fuel switches continue to have benefits for customers, and it is a positive outcome to see successful switches occurring. However, in winter months, when local distribution company demand for gas is high, NSPI can be limited in switching back to natural gas from HFO due to insufficient natural gas pipeline pressure on the pipeline lateral that it shares with the local distribution company, even if economic to do so. We observed one such instance during the Audit Period.

Conclusion X-13: NSPI conducted performance tests on most of its thermal generators during the Audit Period.

Conclusion X-14: NSPI completed and provided ten Root Cause Analyses with another four reported in progress. The completed Root Cause Analyses contained recommendations that NSPI adopted, many of which NSPI has implemented, with 27 recommendations in progress. NSPI should provide the Board an update on the status of these recommendations at the end of 2026. **(Recommendation X-1)**

Conclusion X-15: There were twenty reported forced outages for failed starts at Tufts Cove Units 4 and 5 in 2025, with the primary contributor being a recurring generator vent fan fault that affected both units. The faulty motor was replaced, and NSPI reported no further failed starts after July 31, 2025; in the remainder of 2025, the units started successfully 87 times without further recurrence.

Conclusion X-16: Regarding the efficiency of the LM6000 engines, our review suggests that actual, observed net average electrical efficiencies can differ from OEM-certified efficiency ratings due to a variety of factors. These include ambient temperature, humidity, loading, fuel composition, water-injection availability, and how a unit is cycled. Because of these variables, actual net electrical efficiency values are not directly comparable to OEM-certified values. NSPI provided evidence suggesting that its three LM6000 engines performed reasonably close to the OEM-provided heat rate curves, as adjusted for ISO ambient conditions, exhaust loss, and NOx operating condition. We conclude that FAM customers did not face materially higher fuel costs due to unreasonably inefficient performance of the LM6000 engines.

Conclusion X-17: A November 22, 2024 forced outage event at Tufts Cove 2 due to elevated vibration levels followed a planned maintenance outage. The Root Cause Analysis found that (1) several rotor blades exhibited a loss of welding material at the shroud-to-blade attachment points and (2) significant

deposits were observed on the underside of the blades. The Root Cause Analysis concluded that the most probable cause of the elevated vibration was machine imbalance caused by under-blade deposits not fully removed during the planned outage. As a result of this issue, Tufts Cove 2 was offline from November 22, 2024 through January 6, 2025. When asked if it had estimated the incremental FAM cost of this outage, NSPI indicated that it did not conduct this calculation. We recommend NSPI provide an estimate of the incremental FAM costs incurred during this event. **(Recommendation X-2)**

Conclusion X-18: NSPI's diesel-fired combustion turbines generally experienced Availability Factors that exceeded industry averages, while its DAFORs fell short of industry averages in 2024 but improved and exceeded those averages in 2025. Output from these units was similar in this Audit Period than to the prior Audit Period.

Conclusion X-19: A March 7, 2024 forced outage event at Burnside 1, which occurred when the unit tripped due to high vibration, was caused by a liberated turbine blade. The subsequent investigation determined that the engine, which was purchased by NSPI from the OEM (Wood Group Pratt & Whitney) as a refurbished engine in 2021, had not been refurbished using industry best practices prior to delivery to NSPI. The engine was out of service until December 1, 2024, though a leased engine was installed and operated from July 24, 2024 until the replacement engine was received and installed on December 1, 2024. NSPI negotiated a settlement with the OEM worth \$ [REDACTED] USD in avoided costs of engine refurbishment and the leased engine. When we requested NSPI's estimate of the FAM costs associated with this event, NSPI indicated that it did not conduct this calculation. NSPI further noted that the leased engine allowed Burnside 1 to remain operational during the time the refurbished engine was out of service, avoiding displacement of generation to higher-cost resources. We agree with this point, at least for the period when the leased engine was in place (July 2024-December 2024). However, there was a period where the unit was fully offline, prior to receipt of a leased engine (March 8, 2024-July 24, 2024). It is unlikely this event resulted in significant incremental FAM costs, as Burnside 1 is a high-cost peaking unit rarely operated. Given the nature of this event, however, NSPI should confirm that no incremental FAM costs were incurred, and if they were, to refund those costs to customers, who should bear no costs associated with this event. **(Recommendation X-3)**

Conclusion X-20: Lingan 2 was sustained throughout the Audit Period and incurred close to \$ [REDACTED] in sustaining capital costs. Going forward, the IESO Nova Scotia has taken over responsibility for long-term system planning. In the IESO's recent 10-Year System Outlook, Lingan Unit 2 is forecasted to remain available until "2029/2030," at which point it is retired. This is a revision from NSPI's 2025 10-Year System Outlook, which had forecasted the retirement of Lingan Unit 2 in the Winter of 2027/2028.

Conclusion X-21: On three separate occasions in 2024, Point Aconi was forced offline due to failures of an expansion joint on the air supply to a combustor return leg, which was plugged, restricting ash circulation, causing overheating of the expansion joint and subsequent failure. Collectively, the three outages totaled 308.76 hours and spanned the periods August 16-August 18, August 19-August 20, and August 25-September 4. The blockage consisted of mainly non-combustible material, and leading up to

the outages, the unit was operating with higher coal blend ratios for testing purposes as it was a lower cost option. Since implementation of corrective actions, ash circulation has remained stable and no further related expansion joint failures have occurred. This series of outages represents one impact of such experimental fuel blends and could challenge NSPI in the future as emissions constraints become tighter each year.

Conclusion X-22: On October 26, 2024, Point Tupper was forced offline in an outage that would last 552.37 hours until November 18, 2024 due to a generator trip on under-excitation protection. The trip was traced to a failure within the rotating brushless exciter assembly, specifically involving damage to rectifier diodes and associated fuses. Subsequent inspection identified carbon and dirt accumulation on the exciter components, which contributed to electrical arcing across an insulator and the resulting component failures. Following the event, NSPI has updated the frequency of preventative maintenance to annually as an additional precaution and noted the OEM's suggestion that an engineering study could be performed to validate cleanliness improvements that may be achieved by installing baffles. Given the impact of outages like these, we include a recommendation that NSPI complete its corrective measures and update the Board with an explanation of the measures ultimately implemented. **(Recommendation X-4)**

Conclusion X-23: Point Tupper experienced a forced outage on June 25, 2023, which lasted until August 2, 2023, in which the plant's two CW pumps tripped due to ground faults at separate times. The cause of the two failures was a combination of contamination and moisture that contributed to the motor failures. The Root Cause Analysis found that "less than ideal moisture management in the operating environmental for these motors" was present, "[c]abinet heaters were not fully functional on either motor at the time of failure," and that while "[t]he operating environment is challenging...there are opportunities to improve moisture management." When we requested NSPI's estimate of the FAM costs of this event, which kept Point Tupper offline for 38 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so. That calculation should include the impact of the forced outage (which lasted from June 23, 2023 to July 12, 2023), plus the period in which Point Tupper was derated (through August 2, 2023). **(Recommendation X-5)**

Conclusion X-24: The PHB boiler's process efficiency data suggests the boiler continues to trend in a negative direction since 2019 and reached its lowest point in 2025 (34.3 percent). This is a trend that should be monitored going forward and not minimized due to the complexity of the variables that can influence this performance statistic. In the IESO 10-Year System Outlook, PHB is forecasted to continue to operate in the near future and to increase its annual output (to 250 GWh) in 2030, and NSPI forecasts continued sustaining capital investment in PHB through 2050 at an average of \$■ million/year, including more substantial investments in 2028 (\$■ million) and 2032 (\$■ million). All this suggests that PHB will remain a contributing resource to NSPI's needs and its performance statistics should continue to be tracked and used to inform operational and maintenance decisions.

Conclusion X-25: PHB suffered a forced outage on May 31, 2024 due to a broken Low-Pressure Steam Extraction Control Valve Rod. The Rod was classified by NSPI as a “critical spare” part by NSPI, and NSPI’s inventory records indicated that one spare Rod was held in inventory at the plant. However, following the event, and despite inventory records to the contrary, NSPI was unable to physically locate the Rod at the plant. Unable to locate the spare Rod, NSPI made the decision to undertake temporary repairs to the failed Rod and initiate procurement of a replacement spare. The broken Rod was repaired and added back to the LP Extraction Control Valve system on June 17, 2024, and the PHB unit was returned to service that same day. The Rod was later replaced during the unit’s annual planned outage. When we requested NSPI’s estimate of the FAM costs of this event, which kept PHB offline for 18 days, NSPI indicated it had not conducted such a calculation. We recommend NSPI do so, given that the forced outage lasted longer than what it would have been if NSPI had been able to locate the spare Rod in the immediate aftermath of the event. That calculation should include the impact of the forced outage (which lasted from May 31, 2024 to June 17, 2024), plus the cost of repairs to the failed Rod. **(Recommendation X-6)**

Conclusion X-26: NSPI’s hydro assets produced 30 percent lower output in this Audit Period compared with the prior period, driven primarily by sharp decreases in precipitation during this Audit Period.

Conclusion X-27: Wreck Cove’s ongoing life extension and modernization efforts impacted the plant’s performance metrics during the Audit Period. That work has been subject to delays and is expected to continue in part in 2026. Had NSPI completed the LEM work on Unit 1 and Unit 2 according to the original schedule, FAM customers would have benefited from lower costs during the Audit Period. When requested for the impact of the cost of the delay, NSPI indicated that it had not tracked the cost of delays or outages. Assuming an annual output of 300 GWh from Wreck Cove, NSPI could have received an additional 79.0 GWh in 2024 and 35.7 GWh in 2025. Using the “Fuel Cost per MWh-\$/MWh on Total Generation” reported for 2024 (\$[REDACTED]/MWh⁵⁴⁶) and 2025 (\$[REDACTED]/MWh⁵⁴⁷) as rough estimates of cost, these generation volumes total about \$[REDACTED] million in value. Our assumed price for 2024 (\$[REDACTED]/MWh) is likely conservative, given that this price includes the impact of the Federal Loan Guarantee.

Conclusion X-28: NSPI spent \$[REDACTED] million in OM&G expenses during the Audit Period to maintain the operability of its fleet. These expenses and investments represented an increase of about 9 percent over the prior Audit Period.

Conclusion X-29: During the Audit Period, full-time employee headcount at NSPI’s power plants increased from 596 at the start of the Audit Period to 631, an increase of 5.9 percent. Most notable was the increase in full-time employees at Tufts Cove from 99 to 113 and hydroelectric stations from 79 to 96.

⁵⁴⁶ Q4 2024 FAM Report, tab 1(3).

⁵⁴⁷ Q4 2025 FAM Report, tab 1(3).

Conclusion X-30: Sustaining capital investments totaled \$ [REDACTED] million in the Audit Period, a decrease of 13.6 percent from the prior Audit Period.

Conclusion X-31: NSPI personnel was highly cooperative and professional during each of Bates White's June 2026 site visits to several generating stations and other key NSPI infrastructure locations.

Conclusion X-32: NSPI complied with all fleetwide SO₂ and NO_x limits during the Audit Period. Regarding SO₂, NSPI was assisted by the receipt of the Certificate of Variance for 2025, which increased the allowed emissions for the year from 28,000 tonnes to 45,000 tonnes. Regarding mercury emissions, NSPI emitted more than the annual limit (35 kg) in both 2024 and 2025. In both years, NSPI could apply 10 kg of credits, effectively raising the annual compliance limit to 45 kg. NSPI's actual mercury emissions in 2024 were 35.9 kg, below the credit-adjusted cap of 45 kg. In 2025, NSPI emitted 46.9 kg, above the cap of 45 kg. NSPI's reported mercury emissions for 2025 in its 2025 FAM Annual Report indicated 2025 mercury emissions of 45.0 kg (not 46.9 kg) and indicated no violation of its annual limit in 2025. This was due to NSPI following its "Mercury Monitoring Protocol" which states that if NSPI exceeds an emissions target by 5% or less, it will report the annual limit number as its annual emissions, not its measured emissions for that year.

Conclusion X-33: In 2024, NSPI's GHG emissions were 5.6 mega tonnes and 5.8 mega tonnes in 2025, meeting air quality regulations. NSPI's total OBPS GHG compliance costs were \$ [REDACTED] though that differs from the \$ [REDACTED] reported by NSPI in its FAM reporting. We include a recommendation that NSPI reconcile this difference. **(Recommendation X-7)**

Conclusion X-34: NSPI's opacity exceedances during the Audit Period increased to 120 from 51 in the prior Audit Period.

Conclusion X-35: NSPI received 40.5 percent and 40.2 percent of its energy from renewable sources in 2024 and 2025, respectively, meeting RES targets of 40 percent in both years. NSPI purchased the RECs associated with Surplus Energy from Newfoundland in the amounts of 155 GWh in 2024 (at \$ [REDACTED]/REC) and 275 GWh in 2025 (at \$ [REDACTED]/REC). This is a notable development, as NSPI can use purchase of RECs associated with Surplus Energy as a source of additional RES-compliant generation supply when other sources are insufficient to meet compliance targets. As such, we would expect NSPI to purchase few, if any, RECs from Newfoundland in years in which it receives surplus volumes of RES-compliant supply from its other sources. In the case of 2024 and 2025, NSPI's REC purchases were needed: absent them, NSPI would have not met its RES compliance targets in either year (39.0% in 2024 and 37.6% in 2025).

Conclusion X-36: NSPI has fully addressed our prior audit recommendations related to Power Plant Performance.

Conclusion X-37: NSPI and its project partner settled with Nordex related to breach of contract claims stemming from forced outage and derates at South Canoe first experienced in the prior audit period. The settlement stipulated that Nordex pay NSPI and South Canoe Development Partnership \$ [REDACTED]

which equaled the sum of 2022-2023 damages (\$ [REDACTED] plus interest on that amount (\$ [REDACTED] plus 2023-2024 damages (\$ [REDACTED] NSPI's 49% share of this amount equals \$ [REDACTED] Legal fees and litigation costs totaled \$ [REDACTED] \$ [REDACTED] of which were NSPI's responsibility and which were recovered through OM&G costs, not FAM. As part of the settlement, NSPI and South Canoe Development Partnership also paid Nordex for all outstanding invoices, which totaled \$ [REDACTED] of which NSPI's 49 percent portion was \$ [REDACTED] [REDACTED]

X.D. Recommendations

Recommendation X-1: NSPI should provide the Board an update on the status of the remaining 27 recommendations from the Root Cause Analyses at the end of 2026.

Recommendation X-2: NSPI should provide its estimate of the FAM and non-FAM costs associated with the November 22, 2024 forced outage at Tufts Cove 2 due to elevated vibration levels.

Recommendation X-3: NSPI should provide its estimate of the FAM costs associated with the March 7, 2024 forced outage at Burnside 1 and ensure that FAM customers bear no incremental costs for this outage.

Recommendation X-4: NSPI should update the Board on its corrective measures taken in response to the October 26, 2024 forced outage at Point Tupper by the end of 2026.

Recommendation X-5: NSPI should provide its estimate of the FAM costs associated with the June 25, 2023 forced outage at Point Tupper.

Recommendation X-6: NSPI should provide its estimate of the FAM costs associated with the May 31, 2024 forced outage at PHB, plus the costs of repairs to the failed Low-Pressure Steam Extraction Control Valve Rod.

Recommendation X-7: NSPI should reconcile the difference between the \$ [REDACTED] [REDACTED] in total OBPS compliance cost reported in the audit to the \$ [REDACTED] [REDACTED] provided in FAM reporting.

XI. Commitment and Dispatch

XI.A. Background

A process has been in place since 2021 to study and implement new tools and processes to improve economic dispatch. As of Q1 2026, the Economic Dispatch Optimization Solution (“EDOS”) was not yet implemented. Training for use of the new tools and processes is expected to extend into June 2026 and after training is complete, the overall project is expected go live.⁵⁴⁸ Bates White has not yet been provided the details of the EDOS or the Outage Coordination Solution, so we cannot yet comment on how these new tools and processes will improve economic dispatch. During the current audit period, NSPI continued to employ the same dispatch tools and processes in place since our first audit covering the 2020-2021 period, thus many of the concerns we have identified since then remain the same.

The More Access to Energy Act provided for a phased transition of the system operator from NPSI to an Independent Energy System Operator (“IESO-NS”). Starting in December 2025, the IESO-NS took responsibility for Energy System Planning and part of Energy Resource Procurement. Starting from approximately 2027 the IESO-NS will start its independent system operations.

As a result of the cyber event on April 25, 2025, the dispatch process was directly affected. Use of the PortOps model was lost including the information feeds such as natural gas prices and PortOps operational data from PI. [REDACTED]

[REDACTED]. Some data that was lost in the cyber event was able to be recovered. Other data was unrecovered. We highlight in this chapter missing data. NSPI, to its credit, was able to keep the system running reliably through this very difficult period, but given the loss of information and automation there was inevitably a loss of efficiency that resulted in increased costs. We have not tried to quantify the loss in efficiency due to the cyber event.

XI.A.1. Least Cost Dispatch

NSPI, in its role as scheduler and operator, must determine how best to utilize existing generation, transmission, and other utility assets to provide reliable, lowest cost electricity to its consumers. This is accomplished through the commitment and dispatch process. The dispatch of resources requires daily, hourly, and up to the minute-level determinations of what generators to run and what levels to run them. The overall objective of the commitment and dispatch process is to select the optimal set of generators

⁵⁴⁸ NSP ECC Optimization Tools Project Update, March 2026.

and generator operating points to serve load at the lowest cost while simultaneously maintaining the reliability of the electric system. The dispatch process is commonly referred to as security constrained economic dispatch.

The daily selection of units to operate along with their operating levels is the last step in a much longer process that begins with the planning and building of the electrical system. NSPI—and as of December 2025, the Independent Energy System Operator Nova Scotia (“IESO-NS”)—plans the energy system through an integrated resource planning (“IRP”) process. In the IRP process, decisions about unit retirement or the construction of new resources are made.⁵⁴⁹ Each year outages and maintenance are planned and scheduled. Schedules may be adjusted throughout the year and on a monthly basis as forecasts of load, weather, or other events change. Seasonal hydro schedules are also planned. A week, or in some cases a month, before a given operating day, generators and loads that require more lead time are scheduled. The day prior to the operating day, a specific set of generating units are selected from those that are available and are committed for dispatch the next day. Thus, the choice of units in the commitment and dispatch process necessarily starts with a subset of units from the broader portfolio, and that subset can change from day to day.

Monday through Friday, NSPI executes a daily unit commitment and dispatch process for the next day’s operation (on Friday for the weekend and Monday). The process continues up to the moment of real-time system dispatch. On the day prior to the operation day, unit and system issues are reviewed to determine the set of available units. Unit availability is considered together with fuel availability, as well as cost, trading opportunities, and other system information, to determine a final day ahead schedule. The day ahead schedule is then updated, as needed, up to 2 ½ hours before the actual hour of operation to reflect changes in forecast weather or load, or other unit or system conditions. During the operating hour, generation units are ramped up and down by ECC to balance energy production and consumption at all times while also maintaining system reliability.

The PortOps model is used on a day ahead basis to determine the least cost set of units to meet forecast energy needs. Generating units are ranked in merit order from lowest to highest cost.⁵⁵⁰ At the bottom of the stack are must-run generation units and contracted energy. These energy resources are scheduled regardless of operating cost to address system reliability needs or to fulfill a prior purchase commitment. Next in the stack are the wind generators and small hydro resources. These are typically the lowest variable cost resources and are generally scheduled to run at full output. Next are coal/petcoke, combined-cycle gas, and gas-fired steam turbine units. The ordering of these units heavily depends on the price of natural gas relative to the price of solid fuel. When natural gas prices are low, gas-fired units are less costly than the coal units and precede them in the dispatch order. The list in the right column in Figure XI-1 shows an example of the dispatch order when gas prices are low. At somewhat higher gas

⁵⁴⁹ See, for example, NSPI’s Integrated Resource Plan Action Plan Update. Available online at: https://www.nspower.ca/docs/default-source/irp/irp-action-plan-update-2025.pdf?sfvrsn=1a7257e8_1.

⁵⁵⁰ Each day ahead schedule prior to April 25, 2025 contains a merit order ranking of generation units. Merit order rankings of generation units were not created from April 25, 2025 through the rest of the audit period due to the cyber event.

prices, the dispatch cost of gas and coal units are in the same range. When natural gas prices are high relative to solid fuel prices, gas-fired units are more costly and ranked higher in the stack. The dispatch of the Wreck Cove hydro facility is based on required flows for water management and on the opportunity cost of water and thus can be found at various points in the merit order depending upon these requirements and costs. The Port Hawkesbury Biomass unit (PT Biomass) is dispatched economically with the other units in the portfolio and depending upon relative costs will appear at different points in the dispatch stack. At the very top of the stack are the diesel-fired combustion turbines. Although costly, these units can be started very quickly to respond to immediate system needs and thus provide significant value to system reliability. An example is shown in Figure XI-1.

Figure XI-1: Example Dispatch Stack, December 14, 2024 and June 11, 2025

Rank	December 14, 2024		June 11, 2025
	Unit	Fuel Type	
1	Small Hydro	Hydro	No dispatch stack was created from April 25, 2025 through December 31, 2025 due to the cyber event.
2	Wreck Cove Must Run	Hydro	
3	CC-Tufts Cove Heat Rec	Gas	
4	CC-Tufts Cove 1 LM	Gas	
5	Tufts Cove 1_Gas mode	Gas	
6	Tufts Cove 2_Gas mode	Gas	
7	CC-Tufts Cove Duct	Gas	
8	Tufts Cove 3_Gas mode	Gas	
9	PT Biomass	Biomass	
10	Dispatchable Hydro	Hydro	
11	Point Aconi 1	Coal	
12	Lingan 4	Coal	
13	Lingan 3	Coal	
14	Lingan 2	Coal	
15	Lingan 1	Coal	
16	Trenton 6	Coal	
17	Lingan 4	HFO	
18	Trenton 5	Coal	
19	Lingan 3	HFO	
20	Point Tupper 2	Coal	
21	Tufts Cove 2_Oil mode	HFO	
22	Tufts Cove 1_Oil mode	HFO	
23	Lingan 2	HFO	
24	Wreck Cove Economic Run	Hydro	
25	Tufts Cove 3_Oil mode	HFO	
26	Lingan 1	HFO	
27	Point Tupper 2	HFO	
28	Trenton 6	HFO	
29	Trenton 5	HFO	
30	Point Aconi 1	LFO	
31	Tusket CT	Diesel	
32	Victoria Junction 1	Diesel	
33	Burnside 1	Diesel	
34	Wreck Cove CT Displacement / Contingency Run	Hydro	

The dispatch order is based on incremental cost. NSPI computes, for each unit, the incremental cost at three capacity levels: min, mid, and max. The max capacity level is used to create the dispatch stack. The general form incremental cost formula for thermal units is:

$$\text{Incremental Cost (\$/MW)} = ((\text{Marginal Heat Rate} * (\text{Fuel Price} + \text{Hg Adder} + \text{SO}_2 \text{ Adder} + \text{Limestone Adder})) + \text{VOM} + \text{OBPS Adder}) * \text{Transmission Loss Factor}$$

There are four different types of environmental adders to the Fuel Price that apply depending upon the specific generating unit and time period: Hg (mercury), SO₂, Limestone, and OBPS. Compliance with mercury limits is managed by the injection of powder activated carbon (“PAC”) sorbent in the flue gas. In the current audit period, a value for PAC was reported for the solid fuel units (Lingan 1-4, Pt. Aconi, Pt. Tupper, and Trenton 5-6) that reflected the costs of both the Hg and SO₂ adders, SO₂ compliance is managed in the first instance outside the dispatch process by blending high and low sulphur content solid fuels. For the 2023-2024 period, NSPI had a SO₂ limit of 68 kt, leaving just 31.6 kt of allowed emissions in 2024 (36.4 kt were exhausted in 2023). In 2025, NSPI had a 28 kt limit. To manage these limits, NSPI included an SO₂ adder (within the PAC adder) of approximately \$■/MWh starting February 21, 2024 through March 14, 2025. On March 25, 2025, NSPI received a certificate of variance (“CoV”) for sulfur emissions compliance for the 2025-2034 period. For 2025, the CoV increased the allowable SO₂ emissions from 28 kt to 45 kt. On March 15, 2025, the SO₂ adder was removed from the incremental cost calculation, reducing the PAC adder for the solid fuel units to approximately \$■/MWh for the remainder of 2025. SO₂ emissions at Point Aconi are managed using an adder for the cost of limestone in addition to a PAC adder. It is included in the dispatch equation for Point Aconi for all hours during the audit period.

GHG compliance costs under the Output-Based Pricing System (“OBPS”) apply to each MWh of energy generated from a fossil resource that has a GHG intensity (GHG per MWh) higher than the OBPS-specified intensity level. Generation units with emissions intensity levels below the OBPS-specified rate receive performance credits. The OBPS adder in the dispatch equation is a \$/MW cost similar to the variable operation and maintenance (“VOM”) cost. In some instances, adjustments to the heat rate curves of generating units are also made to model OBPS. For PT Biomass, for example, there is no OBPS adder; rather, OBPS is modelled as an adjustment to the heat rate curve.

The inclusion of emissions adders and heat rate curve adjustments in the dispatch equation changes the relative ordering of units in the dispatch stack, causing some units to be run less often or at lower levels, and others to be run more. In this way, through the commitment and dispatch process, NSPI can manage its emissions constraints. Figure XI-2 shows the adders or adjustments that apply for each generating unit.

Figure XI-2: Emissions (and other) Adders or Heat Rate Curve Adjustments in Dispatch Equation by Unit, 2024-2025

Unit	PAC (H _g +SO ₂)	Limestone (SO ₂)	GHG OBPS
Tufts Cove 1			x
Tufts Cove 2			x
Tufts Cove 3			x
Tufts Cove 4			x
Tufts Cove 5			x
Tufts Cove 6			x
Lingan 1	x		x
Lingan 2	x		x
Lingan 3	x		x
Lingan 4	x		x
Pt. Aconi 1	x	x	x
Pt. Tupper 2	x		x
Trenton 5	x		x
Trenton 6	x		x
PT Biomass			x
Burnside 1-4			x
Tusket CT			x
Victoria Jct 2			x

NSPI also manages environmental constraints through the choice of fuels and fuel blends for solid fuels. These choices will indirectly impact the incremental cost equation through the fuel price. For the Lingan, Trenton, Point Aconi, and Point Tupper units, NSPI implements a quarterly solid fuel blending strategy to comply with emissions constraints. NSPI is able to achieve its NO_x emissions constraints entirely through fuel choice, fuel blending, and use of pollution control equipment, as such there is no adder for NO_x in the dispatch equation.

The dispatch of generation must accommodate system limitations, including those related to transmission, security, or operational constraints. This results in dispatch costs that exceed those of a hypothetical unconstrained dispatch. For example, transfer limits on transmission lines or corridors can require the output of specific generating units to be increased or decreased to reduce the flow of electricity on those pathways. Security constraints that consider the impact of the loss of large transmission or generation resources on the system, as well as voltage or other operational needs, can also require modifications to the least cost dispatch.

Ancillary services, including short-term operating reserves, are jointly optimized with energy to determine the least cost set of resources. Operating reserves are held on units that are either producing energy or that can produce energy within the required timeframe. As a result, lower marginal cost units may be operated at a lower level than they otherwise would be in order to carry reserve capacity, while higher marginal cost units are dispatched to provide the incremental energy. In addition to ancillary

services, the dispatch process must account for the physical capabilities of specific units such as their ramp rates, start-up times, and minimum operating levels. These constraints may likewise result in the dispatch of a higher marginal cost unit. After incorporating all constraints, the final optimized dispatch will result in the lowest overall cost.

XI.B. Findings

XI.B.1. Commitment and Dispatch Process

NSPI's commitment and dispatch process has remained unchanged since the 2021-2022 audit. It is primarily a daily process supported by weekly discussions and analysis. The process was modified from starting on April 25, 2025 to the end of the audit period due to the cyber event.

On a weekly or as needed basis, system security engineers at the ECC run studies to determine transmission transfer limits, and, if necessary for transmission operation, limits on specific generating units. The limits are communicated to NSPI marketing personnel and manually updated in PortOps for the day ahead and real-time dispatch schedules.

[REDACTED]

On Thursdays, NSPI holds the Energy Control Integrated Outage meeting where information regarding transmission constraints and system concerns, unit outages, work requests impacting generation, and unit return to service dates are provided. Members from the Day Ahead desk attend this call and incorporate the information into the day ahead planning and dispatch process.

Each Thursday, a small hydro meeting is held.

Each day, Monday through Friday, the following process is followed:

- At 7:30 AM, a system evaluation is done using the Port Ops model. The model produces an economically optimized system dispatch for the next day, taking into account preliminary information on: net capabilities of the transmission and generation fleet; auto-imported system load, wind, and small hydro forecasts; manual updates of fuel prices, net capabilities concerning generators, IPP availability, and the Extra Large Industrial ("ELI") load forecast; and unit work requests and outage requests. The output from the model run informs the day's marketing activities and discussion with the Natural Gas desk. The Natural Gas desk provides information on pricing and available volumes of gas. The model is run again incorporating this information. The model output informs further discussion with the Natural Gas desk, marketing activities, and preparation for the 9:30 AM call with the NS Power thermal Fleet.
- [REDACTED]
- [REDACTED]

[REDACTED]

- At 9:30 AM, the Energy Marketing group hosts a morning meeting with the NS Power Thermal Fleet. The meeting includes representatives from Lingan, Point Aconi, Trenton, Port Hawkesbury Biomass, Tufts Cove, the combustion turbines, Energy Control Center, and Asset Management. At the meeting, the Energy Marketing group reviews current and forecast temperature as it relates to system load as well as wind generation. Generation staff provides current status, unit availability, and any maintenance or outage requests. Opportunistic times for maintenance and outages are reviewed based on system requirements and economics. Generator concerns and risks are shared and discussed. Representatives from ECC and Asset Management provide questions and/or feedback.
- At 10:00 AM, following the Marketing meeting, the PortOps model is run incorporating updated natural gas pricing data, market information, and current information on the fleet. The output of this run informs the day ahead gas volume requirements and power trade requirements.

[REDACTED]

- At 10:15 AM, gas volumes are procured, informed by the model output.
[REDACTED]
- At 10:30 AM marketing activities including power trades are put in place, informed by the model output.
[REDACTED]
- At 11:00 AM the PortOps model is run again to produce the Day Ahead schedule, incorporating the power and gas transactions. The PortOps model determines the optimal schedules using incremental cost and unit heat rate curves. The schedules show a MW level for each generator for each hour of the operating day. The scheduling information also includes the amount of operating reserve available on each unit, and a dispatch order ranking units from lowest to highest marginal cost. Along with the dispatch order ranking, a marginal cost associated with three operating points (min, mid, and max) for each unit is provided to the System Operator to help guide real-time dispatch.

[REDACTED]

- Between 11:00 AM and 1:00 PM, the Day Ahead schedule, along with meeting notes from the marketing meeting, are sent to Energy Control, the Generation Fleet, PH Paper, and the Real-Time Marketing desk. The Day Ahead schedule, consisting of hourly MW production for each unit, comes into effect 11 hours later at midnight and applies for 24 hours.
- From 1:45 PM to midnight, the Real-Time Marketing desk continues to follow the most recent economically optimized dispatch in the Day Ahead or Intra-Day schedule. The Real-Time marketer continues to monitor system load conditions, look for opportunities to optimize, and conduct buying and selling of energy with counterparties for the 24-hour period starting at midnight. These activities as well as any significant changes in load, generation capability, transmission capability, or other system conditions may result in the generation of a new Intra-Day schedule that replaces the Day Ahead schedule.

[REDACTED]

- On the operating day, the Day Ahead schedule or Intra-Day schedule, if the Day Ahead schedule has been updated, is in effect. The Real-Time marketer continues performing marketing activities and issuing updated Intra Day schedules as needed. These schedules apply to the current day. The Real-Time marketer remains in close contact with the plants on a 24/7 basis; keeps up to date on unit capabilities, unit work requirements, and unit online/offline timing; closely monitors internal and external power market conditions and the opportunity to import/export power economically; and updates the gas sheet and E-tags.

[REDACTED]

- When the operating hour arrives, the System Operator dispatches the system with information provided by the Marketing desks and other real-time system information such as updated gas price, load, and generation and transmission operational data. The System Operator manually adjusts the Day Ahead and Intra Day schedules to balance the system in real time, assisted by Real Time Economic Dispatch (“RTED”) functionality in the Supervisory Control and Data Acquisition/Energy Management System (“SCADA/EMS”) system. The System Operator is responsible for managing operating reserves, the dispatch of Wreck Cove, PH Paper’s demand, the PT Biomass unit, generator operational issues, changes in wind generation, transmission constraints, system interchange, and natural gas burn, among other things.

In summary, the Day Ahead schedule is determined through a comprehensive system evaluation process conducted both on a weekly basis, and every weekday morning from 7:30 AM to 1:00 PM. The Day Ahead schedule applies to a 24-hour period beginning at midnight, with the exception of weekends where the Day Ahead schedule finalized on Friday is applied for a 72-hour period beginning at midnight

on Friday night and ending at midnight on Monday. If Monday is a holiday, the period ends at midnight on Tuesday. Intra-Day schedules are created and replace Day Ahead schedules when conditions change. The system operator uses schedule information, along with other real-time system information, to dispatch the system in real time. [REDACTED]

As stated above, in real time, the System Operator uses various other tools to operate and optimize the system. Units on AGC are dispatched automatically and economically through a RTED functionality in the SCADA/EMS system. For units not on Automatic Generation Control (“AGC”), the System Operator manually dispatches the system relying primarily on real-time information, information provided by the marketing desks, and personal experience and knowledge, to commit or dispatch units in real time. We find that the commitment and scheduling process is based on least-cost optimization with adjustments made to accommodate operating constraints that are not modelled (or not fully modelled) in PortOps. We find that real-time dispatch is geared toward reliability—as it should be—to ensure that sufficient generation and operating reserves are available to serve load, but that disjointed optimization and manual processes may have resulted in inefficient dispatch. We elaborate on specific commitment, scheduling, and dispatch issues below.

XI.B.1.a. Real Time Economic Dispatch (RTED)

NSPI’s RTED functionality enables the system to automatically dispatch units on AGC based on economics. When units are dispatched in this way they are referred to as running in economic mode or “econ-mode.” **Figure XI-3** shows the units and the number of hours that each were run in econ-mode for the period April 25, 2025 to December 31, 2025. Data prior to this period, which encompasses a significant portion of the audit period, was lost as a result of the cyber event. During the 2025 period for which data is available, Lingan units 1, 3, and 4 ran in econ-mode during a small number of hours.

System operator intervention is required when using econ mode to adjust or move units on or off, or switch a unit between AGC ranges. The required manual intervention renders the RTED functionality less useful. In addition, NSPI has found that econ AGC mode is not effective in managing the current fleet under emissions rules and the national and provincial aim to transition to renewable energy. Several generating units are not AGC-capable, and various other units are run near full output, leaving little opportunity for econ mode other than on coal units; coal units, though, maintain slow response times that are difficult to manage in econ-mode.⁵⁵¹ Given these facts, we find that the RTED functionality has limited usefulness as used by NSPI.

⁵⁵¹ 2022-2023 Bates White Audit Report, page 280.

Figure XI-3: Operation of Units in Economic Mode

Unit	2024			2025 April 25 - December 31		
	Econ Mode Hours	Total Operating Hours	Percentage of Operating Hours Run Using Econ Mode	Econ Mode Hours	Total Operating Hours	Percentage of Operating Hours Run Using Econ Mode
Lingan 1	Data unavailable due to the cyber incident			58	4,125	1.4%
Lingan 2				0	1,384	0.0%
Lingan 3				82	4,110	2.0%
Lingan 4				79	4,473	1.8%
Point Aconi				0	3,455	0.0%
Point Tupper				0	4,160	0.0%
Trenton 5				0	2,730	0.0%
Trenton 6				0	4,029	0.0%
Tufts Cove 1				0	923	0.0%
Tufts Cove 2				0	3,534	0.0%
Tufts Cove 3				0	3,716	0.0%
Tufts Cove 4				0	4,775	0.0%
Tufts Cove 5				0	4,934	0.0%
Wreck Cove 1				0	1,594	0.0%
Wreck Cove 2				0	0	-
Total				219	47,942	0.5%

Note: Total Econ Mode Hours represents the number of hours during the period that at least one unit ran in econ-mode. Total Operating Hours is the total number of hours in the period.

For units and hours that generators are not in econ-mode, the NSPSO manually dispatches the system using knowledge and expertise, input from generation planners and operators, and scheduling and other information provided from the marketing desks to determine which units to dispatch and at what levels. We find that the current dispatch process, which relies heavily on manual processes, reduces the efficiency and reliability of the system.

XI.B.1.b. PortOps Operational Failures

During the January 1, 2024 to April 24, 2025 period when PortOps was functional, PortOps regularly failed to operate correctly or could not produce a schedule at all. For example, there were clear scheduling errors, PortOps data uploader errors, errors in PHP dispatch, and model failure to create a day-ahead schedule. Errors in PortOps model run output required constant manual intervention by the marketing desks. These deficiencies should be remedied with the implementation of the new Economic Dispatch Optimization Solution if the PortOps model is replaced.

XI.B.2. Commitment and Dispatch Outside the PortOps Model

XI.B.2.a. Dispatch Tracking – Exceptional Dispatch

NSPI uses a protocol for applying manual adjustments to PortOps schedules and documenting these decisions that are made outside of the PortOps software.⁵⁵² The protocol is used to manually adjust PortOps when inputs cannot be precisely quantified or modelled, or when it would require an impractical level of iterative modelling find a solution. In these situations, the marketing desks or the NSPSO use their professional experience and judgement to manually adjust the commitment of one or more units within the PortOps software which can result in the rerun of the PortOps optimization to produce a revised daily report.⁵⁵³ The Fuel Manual Revision 14, in effect during the audit period, specifies the following criteria:⁵⁵⁴

Deviation Criteria 1: Generator Availability

This criterion applies when there is evidence of an impending forced deration.

Deviation Criteria 2: Wind

This criterion applies when actual wind may deviate from the Day Ahead wind forecast and there is a risk of unit recall or short cycling of a thermal unit.

Deviation Criteria 3: Load

This criterion applies when actual load may deviate from the Day Ahead load forecast and there is a risk of unit recall or short cycling of a thermal unit.

Deviation Criteria 4: Other

This criterion marks situations not captured by the existing criteria.

Deviation Criteria 5: System Operator – System Security

This criterion applies to a System Operator decision to deviate from the PortOps schedule to maintain system security.

Deviation Criteria 6: Exceptional Dispatch Cancelled

This criterion marks when the condition causing the deviation ends.

In the current audit period, PortOps was not operational from April 25, 2025 through December 31, 2025, thus by definition there was exceptional dispatch during this period. In addition, the cyber incident compromised the exceptional dispatch records for 2024 and January-April 2025. However, we were able to review instances of Exceptional Dispatch logged by the Marketers in the Shift Reports. We reviewed the Shift Reports for 2024 and found that, on average, approximately two exceptional dispatches were reported each month. Here are some examples:

⁵⁵² Board Decision, M08195, January 13, 2020, paragraphs 43 through 46.

⁵⁵³ Exceptional Dispatch does not apply to adjustments to unit commitment made by the NSPSO in real time, which are not tracked.

⁵⁵⁴ Fuel Manual Revision 14, Link 14, pages 1-2.

Day Ahead Desk shift log for March 18, 2024

Dispatch Criteria 4: [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Day Ahead Desk shift log for March 22, 2024

Dispatch Criteria 2: [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Day Ahead Desk shift log for May 15, 2024

Dispatch Criteria 4: [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Day Ahead Desk shift log for May 26, 2024

Dispatch Criteria 4: [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

These examples illustrate the over-riding of PortOps unit commitment to incorporate information not captured in the model. We find that tracking exceptional deviations in the Shift Reports provides useful documentation of changes to PortOps unit commitment needed to understand and document model limitations and to track the manual actions taken to resolve them.

XI.B.2.b. Dispatch to Manage Natural Gas Pipeline Pressure and Position

Due to recurrent low gas pipeline pressure issues on the M&NP Mainline, NSPI faces a constraint on the use of natural gas at Tufts Cove and PHB, which is sometimes binding. Low pressure can result when Heritage Gas and NSPI use large volumes simultaneously, the demand on the M&NP US and M&NP Canada system is higher than the supply of gas, or when the [REDACTED] send-out capacity is under the forecast amount. Throughout the audit period, the day ahead and real-time marketing desks monitored gas

pressure at Tufts Cove on a daily basis, and took corrective actions to maintain pressure above 400 psi. Corrective actions can include (a) dropping down PHP operations when PT Biomass was running on natural gas, (b) switching Tufts Cove 2 or Tufts Cove 3 to HFO, and (c) derating or limiting production from Tufts Cove. In February, March, August, and December of 2024, instances were documented of the inability to operate Tufts Cove at full output and dropping of Tufts Cove generation due to insufficient gas pipeline pressure. In February, fuel switching was used to address the problem. In August, Wreck Cove 2 was used to make up lost generation.

We also found instances where the output of units was modified to manage NSPI's natural gas pipeline position. Other than modifying unit output, the pipeline position can be managed by making spot gas trades (potentially at a loss), incurring pipeline penalties, or contracting for physical imbalances. We do not have a concern with the modification of generator outputs to manage the gas position, *per se*, because NSPI operates in an illiquid natural gas market and managing the pipeline position using this method may be the most economical way to do it. Our concern, however, is that we cannot verify that the pipeline position is managed economically because of lack of documentation.

PortOps does not consider physical pipeline pressure low limits, or the balancing of the gas position.⁵⁵⁵ As we found in the prior audit period, NSPI lacks a process to ensure that manual adjustments to manage natural gas pipeline pressure and position are done in the most cost-effective way.

XI.B.2.c. Summary

We find, like we have found in prior audits, that numerous commitment and dispatch decisions are made outside of PortOps. Many of those decisions are based on experience and knowledge of the marketing desks and NSPSO. For example, PortOps may produce a schedule that cycles a unit, but the System Operator may override that schedule because of concerns about the unit's ability to restart. Also, units are dispatched, not based on price, but to address fuel supply issues. Many of these dispatch decisions are made by NSPSO in real time without sufficient information about the associated costs. Also, as discussed further below, much of the dispatch of Wreck Cove and the management of operating reserves is done by the NSPSO in real time, but there is no documented information about the economics of those decisions. NSPI committed in the prior audit period to address these issues in the Economic Dispatch Optimization Solution.

XI.B.3. The Port Hawkesbury Biomass Generator

NSPI jointly optimizes PT Biomass with the other units in its portfolio using PortOps. The PT Biomass unit is included in the day ahead and intra-day schedules, and in the merit order dispatch stack provided to NSPSO. The energy marketing desk keeps in contact with PHP on a 24-hour basis to communicate any issues with PT Biomass operation that may affect the system dispatch plan.⁵⁵⁶ The

⁵⁵⁵ 2022-2023 Bates White Audit Report, page 283.

⁵⁵⁶ Fuel Manual Revision 14, Appendix R.

NSPSO often redispatches PT Biomass in real time for various reasons, such as to manage NSPI natural gas position, to accommodate unit maintenance or repairs that require operation on natural gas, or to balance the system.⁵⁵⁷

To model PT Biomass in PortOps, maximum and minimum unit capacities (MW), a fuel mix, fuel prices, and a heat rate curve are specified. The amount of capacity that is modeled cannot be determined directly and is instead estimated since PT Biomass shares its steam source with PH Paper. The more steam that is used by PH Paper, the less there is to operate PT Biomass. During the audit period, PT Biomass capacity was modelled at an average maximum of 30 MW and an average minimum of 15 MW. In 2024, PT Biomass was off-line in ■ percent of all hours. Of the remaining hours, output was above 30 MWh in ■ percent of the hours and below 15 MWh in ■ percent of the hours, with an average output of 25 MWh per hour. In 2025, PT Biomass was off-line in ■ percent of all hours. Of the remaining hours, output was above 30 MWh in ■ percent of the hours and below 15 MWh in ■ percent of the hours, with an average output of 25 MWh per hour.

Various fuels are used for steam production at the Port Hawkesbury facility. Bark and wood chips are the primary fuels. Natural gas is a secondary fuel source. Natural gas is used mainly to stabilize the heat production especially when the biomass fuel has a high moisture content, or to boost the amount of steam output. Natural gas is also used during periods when biomass is unavailable, or when repairs are needed to the biomass operational infrastructure. During 2024, chips made up approximately ■ percent of the fuel mix. Bark made up roughly ■ percent and natural gas made up roughly ■ percent. In 2025, NSPI estimates that chips made up approximately ■% of the fuel mix, with bark and natural gas making up ■% and ■%, respectively.⁵⁵⁸

The fuel price used in the modelling of PT Biomass is a daily weighted average price of bark, chips, and natural gas.⁵⁵⁹ Bark is the lowest cost fuel source, followed by chips. Over the audit period, the modelled fuel price for PT Biomass ranged from a minimum of ■/MMBtu (August 30, 2024 – September 4, 2024) to a maximum of ■/MMBtu (January 18, 2025 – January 21, 2025). Beginning on April 24, 2025 at the onset of the cyber event, the modelled fuel price was set to ■/MMBtu and was kept at that price through the remainder of the period making it one of the lowest cost units in the dispatch stack.

NSPI develops heat rate coefficients based on an assumed average steam flow requirement of Port Hawkesbury Paper.⁵⁶⁰ The heat rate coefficients for PT Biomass were fixed during the audit period.

⁵⁵⁷ 2022-2023 Bates White Audit Report, page 284.

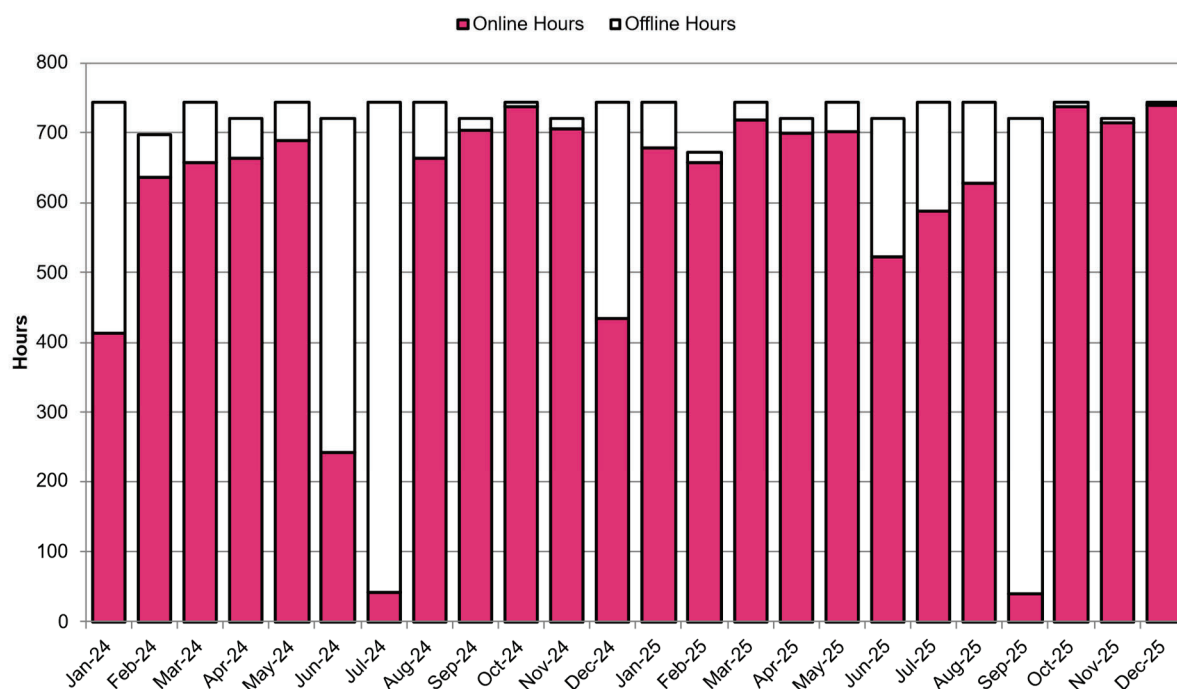
⁵⁵⁸ Fuel mix percentages for 2025 are estimated as of September 2025.

⁵⁵⁹ 2022-2023 Bates White Audit Report, page 285.

⁵⁶⁰ 2022-2023 Bates White Audit Report, page 285.

PT Biomass produced no energy for FAM customers for extended periods in January, June, July, and December of 2024; and in September of 2025. Figure XI-4 shows the number of hours that the unit was producing energy and the number of hours that it was not, for each month in the audit period.

Figure XI-4: Port Hawkesbury Biomass, Hours with Positive Output⁵⁶¹



In 2024 and 2025, PT Biomass produced energy in 75 percent and 86 percent of all hours, respectively.⁵⁶² This is a substantial increase relative to the prior audit period. Figure XI-5 shows the number of hours that PT Biomass produced energy in each year from 2022 to 2025, alongside annual net generation. Between 2022 and 2025, net generation increased by 30%.

Figure XI-5: Operation of the Port Hawkesbury Biomass Facility, 2022 to 2025⁵⁶³

Year	Operating Hours (No. of Hours)	Operating Hours (% of Total Hours)	Net Generation (MWh)
2022	6,119	70%	142,030
2023	6,077	69%	143,074
2024	6,594	75%	162,286
2025	7,533	86%	184,303

⁵⁶¹ This graph features hourly net generation data as opposed to gross generation data, which was unavailable for significant portions of the current audit period as a result of the April 2025 cyber event.

⁵⁶² 2024 and 2025 NSPI Q4 FAM Reports, tabs “11(3)” and “5 (3)”.

⁵⁶³ 2024 and 2025 NSPI Q4 FAM Reports, tabs “11(3)” and “5 (3)”.

We evaluated the economics of PT Biomass by comparing the marginal cost used to determine its day ahead merit order dispatch with NSPI's system marginal cost (system lambda). The comparison is shown in Figure XI-6. We find that, with some minor exceptions in the first half of 2024, PT Biomass was economic throughout the period. This is a result of the OBPS adjustment to the unit's marginal cost and the fixed fuel price adopted for the period April 24, 2025 through December 31, 2025. We discuss the OBPS adjustment further below.

Figure XI-6: PT Biomass Day Ahead Marginal Cost and System Lambda⁵⁶⁴



The modelling of PT Biomass in PortOps is done using estimated average parameters. The unit's capacity is based on historical averages. The fuel price is modelled as a weighted average of estimated prices and estimated quantities of bark, wood chips, and natural gas. The actual quantities of each type of solid fuel used in the fuel blend are not determined until after-the-fact when the amount of each fuel actually used and its cost is reconciled on a monthly basis. Also, the marginal cost is not calculated using the natural gas price when the unit is dispatched, at the marginal, using natural gas. We find that even though fuel costs and heat rates in the marginal cost calculation are imprecise or incorrect, the OBPS adjustment makes the unit economic in most hours.

⁵⁶⁴ The system lambda shown here is the daily average of hourly on-peak system lambda.

XI.B.4. Port Hawkesbury Paper

Port Hawkesbury Paper (“PHP”) takes service from NSPI under the Extra Large Industrial Active Demand Control (“ELIADC”) tariff. The tariff allows NSPI to manage PHP load to reduce system costs to the benefit of FAM customers. This is done by scheduling PHP to run when system marginal costs are low, for example in overnight hours, and reducing PHP operations in high demand, high cost periods such as during the peak winter months. NSPI measures the benefits of active demand control (“ADC”) on an annual basis. The methodology used to measure these benefits has proven over time to be inadequate, obscuring the actual benefits of ADC. We discuss this more fully in Chapter XV.

For scheduling and dispatch purposes, PH Paper’s load is separated into nine distinct operating modes (“OMs”). The OM Characteristics Schedule specifies minimum and maximum operating levels, the minimum and maximum operating time limits, ramp rates, and pulp production or consumption rate for each OM.⁵⁶⁵ The operating ranges for each OM are set to coincide with operation of mill equipment: the paper machine, the bleacher, and the three pulp lines. OM9, for example, coincides with operation of all this equipment while OM6 coincides with the operation of the paper machine, the bleacher, and pulp line 3 only.⁵⁶⁶

After the final Intra Day Demand Schedule for PHP load is set, the NSPSO may may change PHP’s dispatch in real time to address a change in system conditions or PHP needs. The change in dispatch, which results in schedule “deviations,” may be initiated for various reasons including:

- Ramp for excess energy
- Re-dispatching of generation from Wreck Cove (i.e., WC must run)
- Re-dispatching for change in NS Power export or import
- Transmission restriction
- Drop load for energy supply shortage
- PHP equipment failure
- PHP fail to start
- PHP requested test, (i.e., 20 minute ramp up then down for a test)
- PHP decision to go off schedule (e.g., to meet shipping deadline)

NSPI has been unable to calculate the benefits or costs of real-time deviations, so the impact on FAM customers of real-time active management of PHP’s load is unknown. This is discussed further in Chapter XV.

Due to the interruptibility of PHP load, NSPI can count it as operating reserve. In practice, PHP's load is *not* used to fulfill reserve requirements that are part of the day ahead and intra-day schedules. However, PH Paper's capacity is made available to the NSPSO in real time (except for approximately [REDACTED] [REDACTED] to count as reserve when a generation-based reserve deficit is experienced. We find that given the high number of hours that PH Paper load does not materialize because of equipment or process failures, NSPI's conservative approach to counting PH Paper's load as operating reserves is prudent.

XI.B.5. Wreck Cove

There have been no changes to the commitment and dispatch process for Wreck Cove since the 2020-2021 Audit Period. The process starts with a determination of a weekly or monthly target hydro volume by the Wreck Cove Group to manage water flow and reservoir levels. The target volume depends on the season and other variables including:

- Current liquid volumes storage;
- Snowpack storage;
- Current flow at lower lakes;
- Forecast precipitation;
- Forecast temperature - freezing and melting conditions and expectations;
- Liquid storage capacity projected to be available; and
- Operational requirements (outages, maintenance and testing).

Using the opportunity cost of water allows NSPI to manage a limited water supply to generate energy when most valuable and to be available to provide energy quickly when needed.

There is a varying degree of rigidity to the target volumes depending upon the time of year. During some periods, the monthly or daily target volumes are soft with the objective to move an estimated amount of water over a multi-month period. In other limited periods, when water levels are high, the daily or monthly target volumes are hard. The Wreck Cove operator may require the generators to be run to avoid spilling water. For 75-80% of the year, the target volumes are less of a concern, giving more flexibility to schedule hydro based on economics and for the NSPSO to use Wreck Cove to balance the system in real time.⁵⁶⁷

Once the target level is determined, it is apportioned between a fixed and an incremental amount. The fixed amount will automatically be included in the day ahead schedule. A dispatch price is assigned to the

⁵⁶⁷ 2022-2023 Bates White Audit Report, pages 290-291.

incremental volume and set to displace the most expensive generation and run the required volume of hydro. The dispatch price is reviewed at least daily, and changes are entered in the PortOps model and reflected in the day ahead schedule while the required volume is being run. The PortOps model is used to calculate how to dispatch Wreck Cove to fulfill the hydro target, over the hours within that weekly or monthly period, by apportioning incremental volume that is subject to a variable dispatch price.

There is frequent communication between the Wreck Cove operator and the day ahead marketing desk to discuss operating issues, outages, repairs, and storage levels. After consideration of these constraints, and especially during times with harder targets, the Wreck Cove operator and the day ahead marketer may agree on an adjustment to the target dispatch level.

The NSPSO dispatches Wreck Cove in real time using the schedule provided by marketing and information about water levels and generator status. In real time Wreck Cove is used for balancing the system to replace lost generation or accommodate increased generation, to maintain reserves, to balance the gas position, to accommodate energy trading, or to respond to other real-time system needs.

During the audit period, Wreck Cove units were down for extended periods of time to support the Wreck Cove Life Extension and Modernization Project, which was delayed into the current audit period. NSPI managed the work on the Wreck Cove units to try to keep at least one unit available. Unit 1 was out of service from January 1, 2024 through mid-August 2024. It was on planned outage from September 2024 to November 2024 to complete tunnel repair work. The outage was extended from November 2024 to early January 2025 due to unexpected challenges integrating the new unit into NS Power's operational system. Unit 2 was removed from service in September 2024 and remained out-of-service through the remainder of the audit period.

WC1 operated in just 251 hours during 2024 (note that WC1 operated in only 544 hours in 2022, and not at all in 2023). This means that WC1 was essentially out-of-service for the three-year span from 2022 through 2024. In 2025, WC1 operated in 3,737 hours. WC2 operated in 3,182 hours during 2024 and not at all in 2025. Wreck Cove plays a key role in real-time dispatch, and when Wreck Cove is not available the NSPSO has to rely on other less flexible coal and gas units to perform the functions typically performed by Wreck Cove. Loss of flexibility and higher dispatch costs are unavoidable when Wreck Cove is unavailable.

XI.B.6. Lingan 2

Lingan 2 was operated in 2,167 hours in 2024 and 2,526 hours in 2025 during twelve distinct operating periods. These are shown in Figure XI-7.

Figure XI-7: Operating Intervals during Audit Period, Lingan 2

Event No.	Start Date	End Date	Number of Days	Net Generation (MWh)
1	1/23/24 6:00 PM	2/1/24 1:00 AM	8	21,631
2	2/6/24 8:00 PM	2/14/24 1:00 AM	7	16,765
3	2/21/24 3:00 AM	2/28/24 4:00 AM	7	13,965
4	6/20/24 10:00 AM	6/27/24 8:00 PM	7	10,880
5	8/2/24 6:00 AM	9/11/24 11:00 PM	41	57,015
6	10/27/24 8:00 AM	11/8/24 2:00 AM	12	23,530
7	12/3/24 7:00 AM	12/11/24 3:00 AM	8	20,508
8	1/14/25 2:00 PM	1/20/25 10:00 AM	6	15,698
9	1/22/25 10:00 AM	3/5/25 4:00 AM	42	93,324
10	4/29/25 6:00 AM	5/6/25 2:00 PM	7	10,405
11	11/5/25 8:00 AM	11/25/25 5:00 PM	20	49,614
12	12/2/25 1:00 AM	1/1/26 12:00 AM	30	82,741

Lingan 2 was used more heavily than the prior audit period. Under the rules of its operation, it can only be run when required for system security reasons. The rationale given for its use in the audit period is “Large supply deficiency; firm load in jeopardy without LIN2.” Reported deficiencies in system margins that triggered the commitment of Lingan 2 ranged between 80 MW and 275 MW. Once Lingan 2 was committed, it was dispatched economically during the commitment period (determined by the NSPSO) through the PortOps model or, during the post-cyber event period, by using Plexos together with marketer and NSPSO discretionary decision-making.

Once Lingan 2 is on line and operating it is difficult to evaluate the subjective criteria used by the NSPSO to keep it online for extended periods. We note that once Lingan 2 is brought on line, it is kept online for a period of time to allow thermal stresses to stabilize (typically a week).⁵⁶⁸ We find that the development of additional criteria for keeping Lingan 2 online after it has been called to service for system security reasons would provide clarity and assurance to FAM customers that Lingan 2 is run only when absolutely necessary. (**Recommendation XI-2**)

XI.B.7. Out-of-Merit Dispatch of Solid Fuel Units

In many hours during 2024, all the solid fuel units (Lingan, Pt Aconi, Pt Tupper, and Trenton) were scheduled out-of-merit. This largely coincides with the period that the SO₂ adder was included in the marginal cost equations for these units. As an illustrative example, Lingan 1 was operational during █ % of hours between March 1, 2024 and August 1, 2024, inclusive. During these hours, Lingan 1 was

⁵⁶⁸ 2022–2023 Bates White Audit Report, page 292.

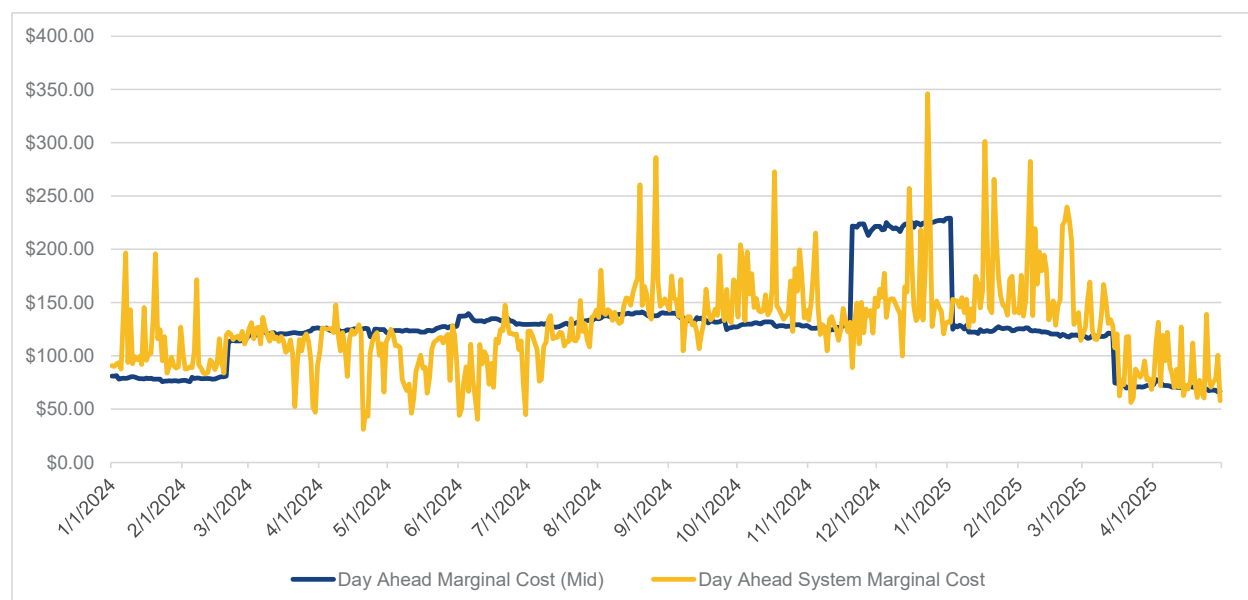
scheduled out of merit █% of the time; in those hours the unit marginal cost was greater than the day ahead system marginal cost. This is shown in Figure XI-8.

Figure XI-8: Day Ahead Unit Marginal Cost vs Day Ahead System Marginal Cost, Lingan 1



In the latter part of November and all of December 2024, a fuel supply shortage drove up the marginal fuel costs at Trenton 5 and 6. During this period, both units were scheduled out-of-merit for most hours. Figure XI-9 illustrates the out-of-merit day ahead schedules for Trenton 6 during this period.

Figure XI-9: Day Ahead Unit Marginal Cost vs Day Ahead System Marginal Cost, Trenton 6



NSPI has represented that emissions adders are included in the calculation of day-ahead system marginal cost, but given the frequency of day-ahead marginal costs above the day-ahead system marginal costs for all solid fuel units in the March to August period in 2024, it appears that they may not have been included. Also, the fuel adder for Trenton implemented to reflect reduced fuel supply appeared in the marginal cost equations for these units but appears not to be reflected in the day ahead system marginal cost. Accordingly, we find the day-ahead system marginal costs reported during a large portion of hours in 2024 appear to be understated and not reflective of the actual day-ahead marginal cost.

XI.B.8. Management of GHG Emissions through Commitment and Dispatch

On January 1, 2023, the Nova Scotia provincial government (Nova Scotia) implemented an output-based pricing system (“OBPS”), replacing the prior Cap & Trade program. Unlike the Cap & Trade program that was based on reducing total emissions regardless of the source, OBPS sets performance standards for individual generators and fuel types. This allows production and emissions to increase without penalty for facilities that meet or exceed their performance standards.

Performance standards are emissions rates or intensities (tonnes/MWh) based on fuel type. Under the OBPS structure, each MWh of electricity generated will either be subject to GHG Fund Credit obligations (amounts that must be paid by NSPI if the recorded emissions rate is higher than the standard) or GHG Performance Credits (amounts that are credited to NSPI if the recorded emissions rate is lower than the standard). In the early years of the program, including the current audit period, natural gas generators have GHG OBPS intensity allowances much lower than their historical actual intensities, while solid fuel-based generators have GHG OBPS intensity allowances closer to historical actuals, effectively favoring the coal/solid fuel fleet in the dispatch relative to the natural gas fleet, all things equal.⁵⁶⁹ Although OBPS makes coal/solid fuel more attractive from a dispatch perspective, this effect was diminished in the current audit period because limited SO₂ allowances were managed with an additional fuel cost adder on solid fuel units that worked to raise the cost of solid fuel units relative to those run on natural gas.

Under OBPS, the Port Hawkesbury Biomass plant is treated as a natural gas plant that uses biomass to offset GHG emissions from natural gas. As such, PHB generates GHG OBPS Performance Credits that are used to offset the cost of the GHG OBPS Fund Credit payment obligations generated by other units on the system.⁵⁷⁰

The price of Fund/Performance Credits (\$/tonne of emissions) follows the federal government’s backstop carbon price. In 2024 and 2025, the credit prices were \$80 and \$95/tonne, respectively. On May 15, 2026, the federal government updated the headline price trajectory for all industrial carbon pricing

⁵⁶⁹ 2022-2023 Bates White Audit Report, page 293.

⁵⁷⁰ 2022-2023 Bates White Audit Report, page 293

systems in Canada. The new guidelines stipulate a credit price of \$100/tonne in each year from 2027 through 2029, followed by a hike to \$115/tonne in 2030.⁵⁷¹

The dispatch costs of all fossil units in NSPI's fleet include OBPS cost adders. The purpose of the adders is to adjust incremental costs to reflect emissions costs. This causes a re-ordering of the merit order dispatch.

Figure XI-10 shows the OBPS adders to marginal cost that were implemented by NSPI since the start of the program. The relatively high adders for Tufts Cove (when run on natural gas) and Point Aconi make these units more expensive relative to Lingan, Point Tupper, and Trenton and would result, all things equal, in reduction in their dispatch relative to these units.

Figure XI-10: OBPS Adders to Marginal Cost – Mid-Range Generator Operating Point (\$/MW)

Unit	2023 (\$/MW)	2024 (\$/MW)	2025 (\$/MW)
Lingan 1-4			
Point Aconi			
Point Tupper			
Trenton 5			
Trenton 6			
Tufts Cove 1-3 (Gas)			
Tufts Cove 1-3 (Oil)			
Tufts Cove 4-6			
PT Biomass			
Burnside 1-4			
Victoria Junction 1-2			
Tusket			

Total costs to comply with OBPS in 2024 and 2025 were \$32.4 million and \$8.5 million, respectively. PHB generated credits of \$ [REDACTED] /month to NSPI in 2024, and \$ [REDACTED] /month in 2025. The Tufts Cove units (1-6) generated a payment obligation of \$ [REDACTED] /month and \$ [REDACTED] /month in 2024 and 2025, respectively. These results are expected given the OBPS pricing framework. There were some unexpected results too. Lingan 1-4 generated credits of \$ [REDACTED] /month to NSPI in 2025, with \$ [REDACTED] generated in May alone. The Trenton units also generated credits to NSPI but more consistently over the whole period. In 2024 they were on average \$ [REDACTED] /month and in 2025 they were over twice that amount at \$ [REDACTED] /month.

Figure XI-11 shows NSPI's GHG emissions in 2021 through 2025 measured in tonnes of carbon equivalent (CO₂e). Total emissions have increased relative to 2023. In 2025 emissions were above the

⁵⁷¹ See Carbon Pricing Systems across Canada, available at <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html>.

2023 level by 803,116 tonnes, or 16 percent. Ironically, one of the drivers of the increased emissions is the OBPS carbon-pricing mechanism.

Figure XI-11: CO₂eq emissions in tonnes⁵⁷²

Units		2021	2022	2023	2024	2025
Lingan	Unit 1	2,637,870	2,110,642	1,541,267	1,643,685	2,100,732
	Unit 2					
	Unit 3					
	Unit 4					
Point Aconi	Unit 1	589,431	978,708	876,703	876,083	756,838
Point Tupper	Unit 2	744,119	612,885	501,730	587,774	729,829
Trenton	Unit 5	1,067,313	942,904	832,368	858,447	1,087,608
	Unit 6					
Tufts Cove	Unit 1	994,498	1,065,426	1,147,712	1,307,583	944,528
	Unit 2					
	Unit 3					
	Unit 4					
	Unit 5					
	Unit 6					
PT Biomass	Unit 3	50,457	40,177	20,419	28,101	14,024
	Unit 4					
Imports		2,645	73,682	85,521	243,977	175,276
Annual Total		6,086,333	5,824,424	5,005,719	5,545,651	5,808,836

2025 emissions from the Lingan units are up by 36% over the 2023 level and emissions from the Tufts Cove units are down by 18%. In 2024, Tufts Cove output increased above 2023 levels to accommodate system needs, which accounts for the higher emissions in 2024. The increase in output and emissions at Lingan, Point Tupper, and Trenton reflect, in part, the carbon pricing in the OBPS mechanism. The increase in output (MWh) from these units can be seen in Figure XI-12.

⁵⁷² 2022-2023 Bates White Audit Report, pg. 295.

Figure XI-12: Annual Generation (MWh)⁵⁷³

Units		2022	2023	2024	2025
Lingan	Unit 1	2,180,119	1,532,900	1,559,503	2,195,760
	Unit 2				
	Unit 3				
	Unit 4				
Point Aconi	Unit 1	908,652	782,620	782,438	670,857
Point Tupper	Unit 2	625,187	480,727	563,036	690,323
Trenton	Unit 5	979,546	872,454	858,244	1,127,222
	Unit 6				
Tufts Cove	Unit 1	1,838,872	2,035,005	2,369,293	1,631,922
	Unit 2				
	Unit 3				
	Unit 4				
	Unit 5				
	Unit 6				
PT Biomass	Unit 3	142,030	143,074	162,286	184,303
	Unit 4				
Imports	NS Block	2,396,995	2,679,183	2,706,441	2,963,896
	Other	935,949	1,451,549	1,377,693	1,133,958
Annual Total		10,007,350	9,977,512	10,378,935	10,598,242

Both natural gas prices (relative to the prices of solid fuel) and the OBPS adders affected the merit order dispatch in the audit period. Gas prices spiked in January, February, and December of 2025, raising dispatch costs for Tufts Cove in 2025 (and reducing output). As already noted, the OBPS adders favor the dispatch of solid fuel units before gas-fired units. Also, from February 21, 2024 through March 14, 2025, the SO₂ adder raised the dispatch cost of solid fuel units. Figure XI-13 shows a high level picture of the total impact of these factors on the dispatch order. In 2024, low gas prices and the SO₂ adder on solid fuel units overcame the OBPS adder effect on gas-fired generation, resulting in TUC-3 and TUC-1 being highly dispatched. In 2025, however, higher natural gas prices and the OBPS adder had the effect of substantially reducing TUC-1 and TUC-3 in the dispatch order and the amount energy produced.

⁵⁷³ 2022-2025 Q4 Quarterly Reports “2 (3).”

Figure XI-13: Operating hours and output by unit, 2024 and 2025

Rank	2024			2025		
	Unit	Total Operating Hours	Total Output (GWh)	Unit	Total Operating Hours	Total Output (GWh)
1	TUC-5	7,814		PHB-1	7,527	
2	TUC-4	7,696		TUC-4	7,061	
3	TUC-3	7,219		TUC-5	6,952	
4	TUC-6	6,945		TUC-6	6,805	
5	POA-1	6,651		POT-2	6,672	
6	PHB-1	6,554		LIN-1	6,544	
7	LIN-3	6,189		TRE-6	6,408	
8	TUC-1	6,109		LIN-3	6,046	
9	TRE-6	6,053		POA-1	6,045	
10	LIN-1	5,842		LIN-4	5,865	
11	POT-2	5,829		TUC-3	5,788	
12	TUC-2	5,496		TUC-2	4,874	
13	LIN-4	4,601		TRE-5	3,916	
14	TRE-5	3,078		WC-1	3,372	
15	WC-2	3,024		LIN-2	2,516	
16	LIN-2	2,155		TUC-1	2,248	
17	BS-1	217		BS-1	276	
18	BS-2	194		BS-2	208	
19	BS-3	152		BS-3	197	
20	BS-4	112		BS-4	153	
21	VJ-2	58		TUS-1	125	
22	VJ-1	46		VJ-1	105	
23	TUS-1	19		VJ-2	64	
24	WC-1	0		WC-2	0	

XI.B.9. Operating Reserves

Operating reserve is generation capacity above system demand required to supply energy on short notice to ensure reliable operation of the electric system. NSPI carries two types of operating reserve: ten-minute reserve, made up of both synchronized (spinning) and non-synchronized (non-spinning) reserve, and thirty-minute reserve.

Ten-minute reserve, is reserve that must be fully available in ten minutes. Under NPCC Directory No.5, NSPI is required to carry 10-minute reserve at least equal to its Most Severe Single Contingency.⁵⁷⁴ NSPI, under a reserve sharing agreement with the New Brunswick Power System Operator, is required to hold a minimum of 136 MW of 10-minute non-synchronized reserve and 32 MW of synchronized

⁵⁷⁴ See, NPCC Regional Reliability Reference, Directory # 5: Reserve. Available at: <https://www.npcc.org/standards/regional-criteria>.

reserve, for a total minimum requirement of 168 MW. This is typically NSPI's Most Severe Single Contingency and equals the net output of the Point Aconi generator.

Thirty-minute reserve is synchronized and non-synchronized reserve that can be utilized in thirty minutes excluding capacity assigned to ten-minute reserve. NSPI is required by NPCC to carry thirty-minute reserve to meet half of its second largest contingency. During the audit period, under the Interconnection Agreement between NSPI and NBP-SO, NSPI was required to carry 50 MW of 30-minute reserve. To maintain tie line flows within required limits, NSPI also plans for 16 MW of upward and 16 MW of downward regulation service.

There are numerous circumstances under which additional amounts of reserve are held. Transmission constraints, for example, can restrict the flow of available energy from Cape Breton, requiring additional reserve on mainland Nova Scotia, or imported energy may become the largest possible contingency, requiring additional ten-minute reserve. In these cases, NSPI will hold reserves above the 168 MW minimum.

Energy and operating reserves (10-minute and 30-minute reserves) are co-optimized using PortOps to determine the amounts that each unit will provide in the day ahead schedules. For generators that are synchronized to the grid, the amount of reserve they can provide depends upon the output of the unit at any given time and the unit's ramp rate. The day ahead schedules show the MWs of ancillary services (operating reserves and regulation) provided by each generator in the PortOps economic solution and the MWs available above the contributed MWs. The System Operator uses the Day Ahead schedule, experience and knowledge of the system, real-time facility deratings, and the real-time ancillary services requirements to dispatch units to provide operating reserves in real time. The total amounts of operating reserves on the system are tracked electronically so the System Operator can ensure that adequate operating reserves are being held at all times.

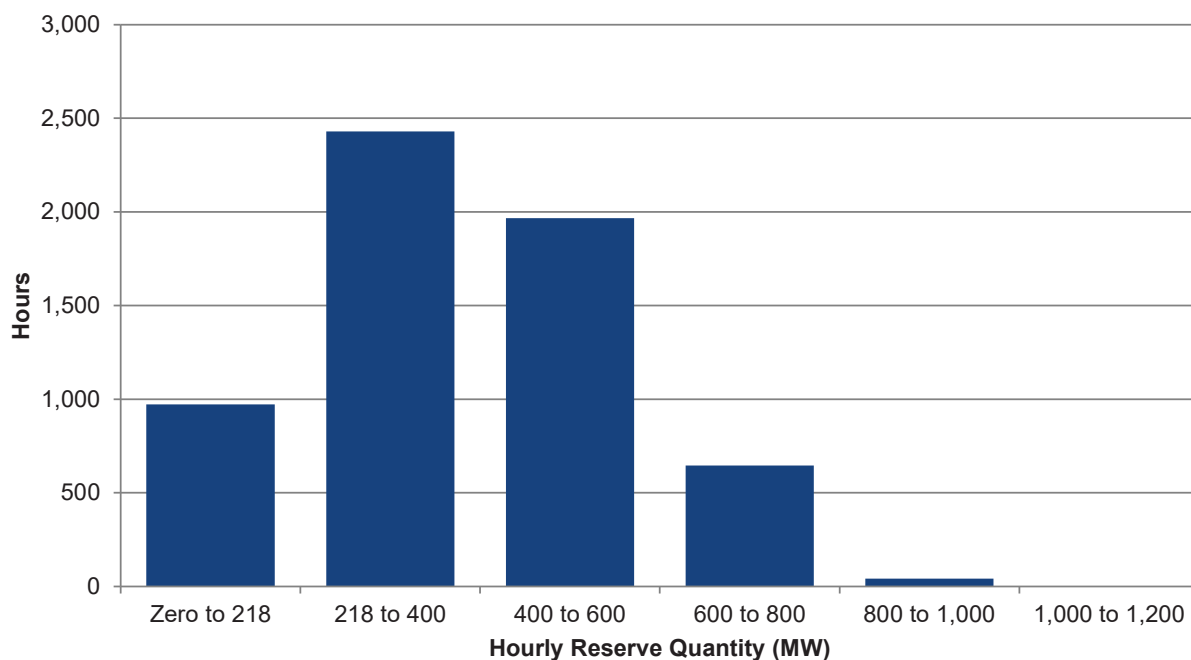
Due to the cyber event, NSPI ten-minute and thirty-minute operating reserve data is not available for the entire calendar year 2024 or for the period January 1, 2025 – April 24, 2025. Since we lack data to make comparable annual comparisons, we exclude data for 2024 and 2025 in Figure XI-14 which shows the number of hours with reserve deficiencies. However, we note that in the period for which data is available, there were 10-minute reserve deficiencies in 42 hours and 30-minute reserve deficiencies in 23 hours.

Figure XI-14: Number of Hours with Reserve Deficiencies, 2020-2025⁵⁷⁵

Year	10-Minute Reserve Deficiencies	30-Minute Reserve Deficiencies
2020	4	76
2021	49	222
2022	121	1,410
2023	56	883
2024	Data unavailable due to the cyber incident	
2025		

Figure XI-15 shows the frequency of various levels of operating reserves for the period that data is available. The amount (MW) of hourly operating reserves was most frequent in the 218 MW to 400 MW range above the minimum requirement.

Figure XI-15: Hourly Operating Reserves, Apr 25 – Dec 31, 2025



We do not make any findings with respect to operating reserves in the current audit period due to lack of data. We note however that generally the NSPSO does not have cost information or real-time optimization tools required for efficient dispatch of operating reserves. These deficiencies should be

⁵⁷⁵ 2022-2023 Bates White Audit Report, Figure XI-13.

remedied with the implementation of the new Economic Dispatch Optimization Solution.

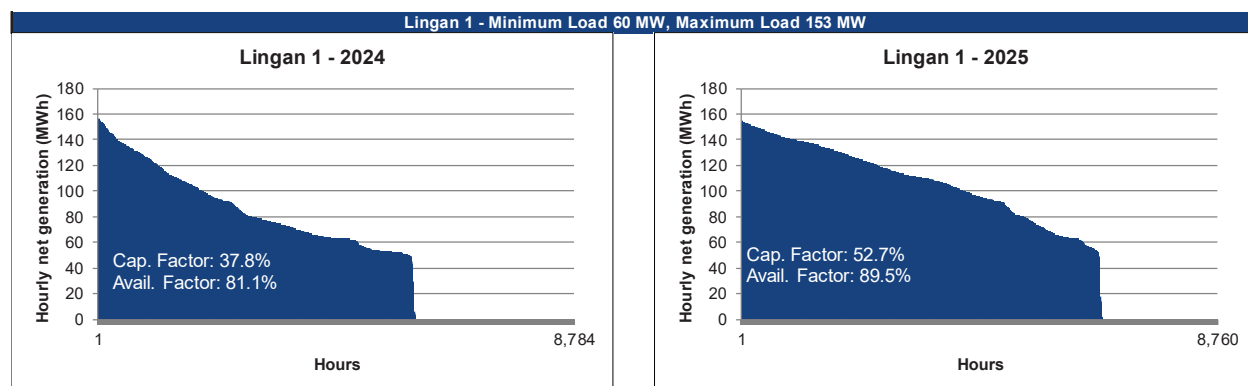
(Recommendation XI-1)

XI.B.10. Unit Loading Levels and Start-up Costs

XI.B.10.a. Unit Loading Levels and Start-up Costs

NSPI's coal and gas-fired units achieve their lowest average cost when operated near maximum output. Operating fewer units at higher levels, when possible, can reduce costs to FAM customers. The figures below show the operating profiles of NSPI's coal and gas-fired units. In each figure, hourly MWh output for all hours is shown, arranged from highest to lowest. This allows one to quickly see the level of output at which each unit operates over the course of a year. In 2024, Tufts Cove 1 and Tufts Cove 3 had the highest capacity factors at 60.9% and 62.3%, respectively. Those dropped significantly in 2025. In 2025, Trenton 6 and Point Tupper had the highest capacity factors at 56.8% and 54.3%, respectively. Generally, the Lingan units and Trenton 5 have low capacity factors. Lingan 2's low capacity factors reflect its reserve-only status implemented in August 2022.

Figure XI-16: Lingan 1 Load⁵⁷⁶



⁵⁷⁶ There are a number of instances over the audit period in which recorded hourly net generation exceeds the maximum load for a given unit. Such instances were explained as “glitches in data flow from SCADA into [the] database.” The erroneous datapoints were interpolated during the importation into various processes that rely on the data. Bates White counted a total of 21 hours across the audit period in which the units graphed in the aforementioned figures were impacted by the described glitches.

Figure XI-17: Lingan 2 Load

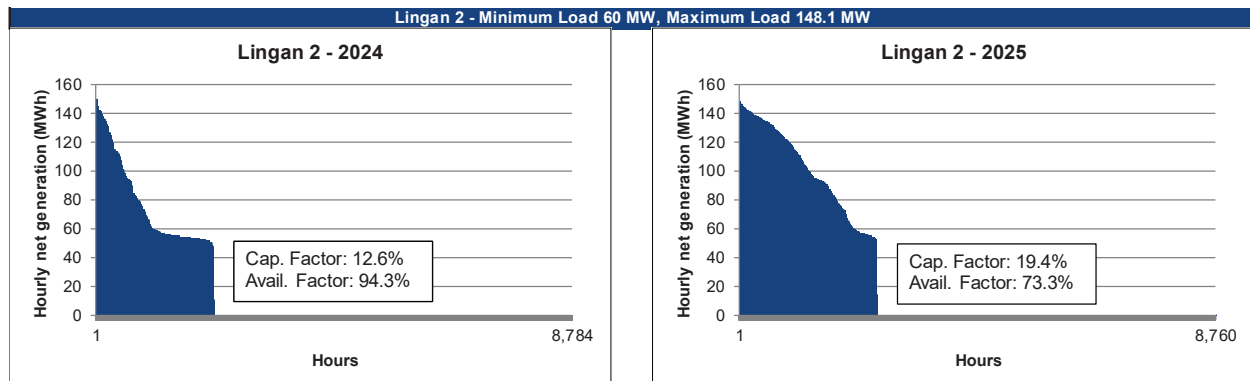


Figure XI-18: Lingan 3 Load

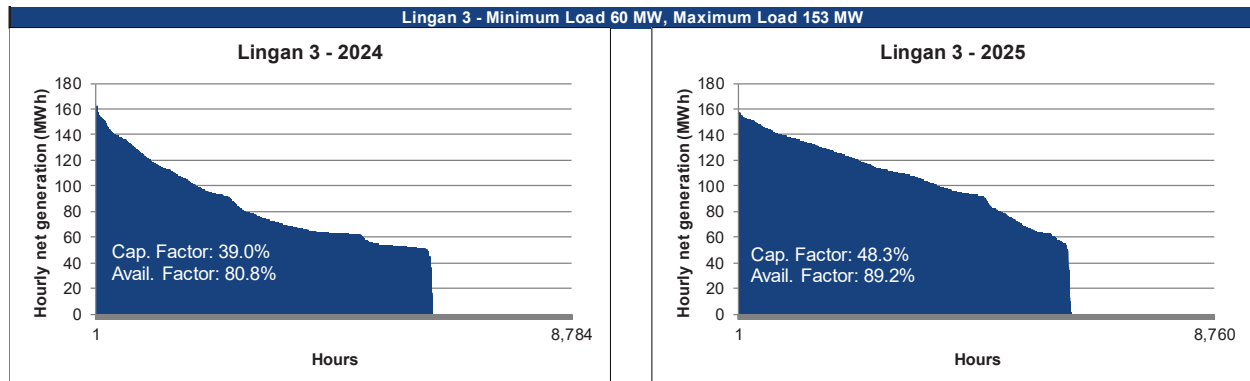


Figure XI-19: Lingan 4 Load

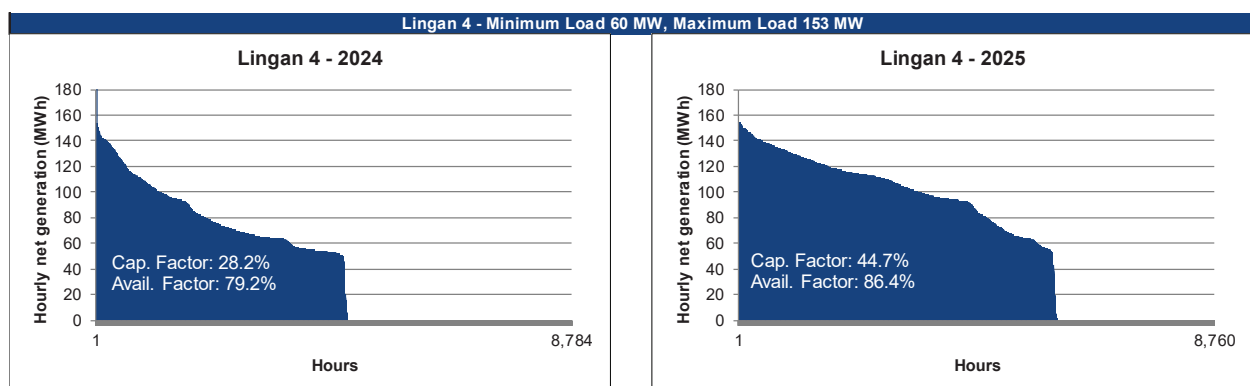


Figure XI-20: Point Aconi Load

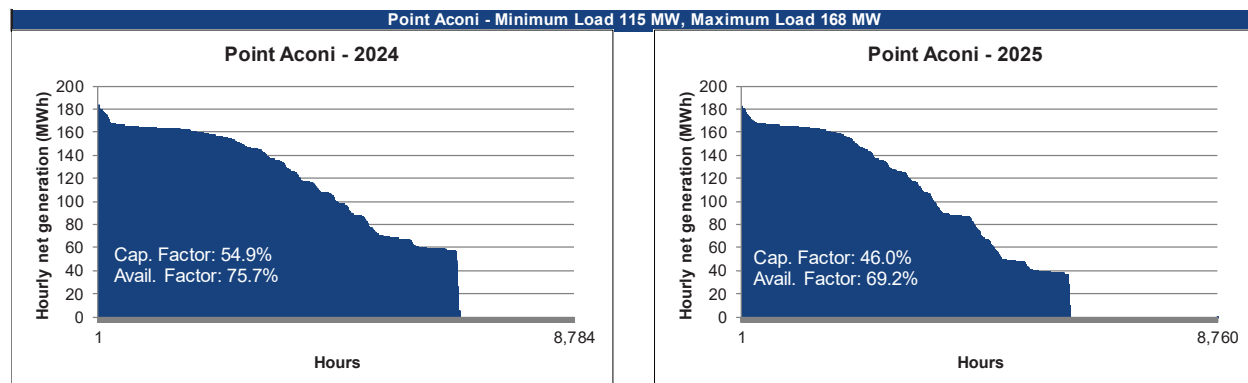


Figure XI-21: Point Tupper Load

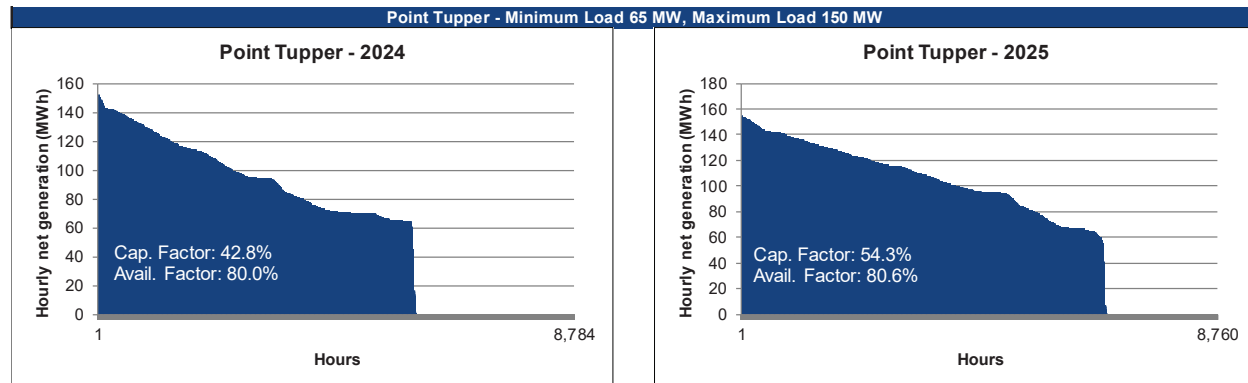


Figure XI-22: Trenton 5 Load

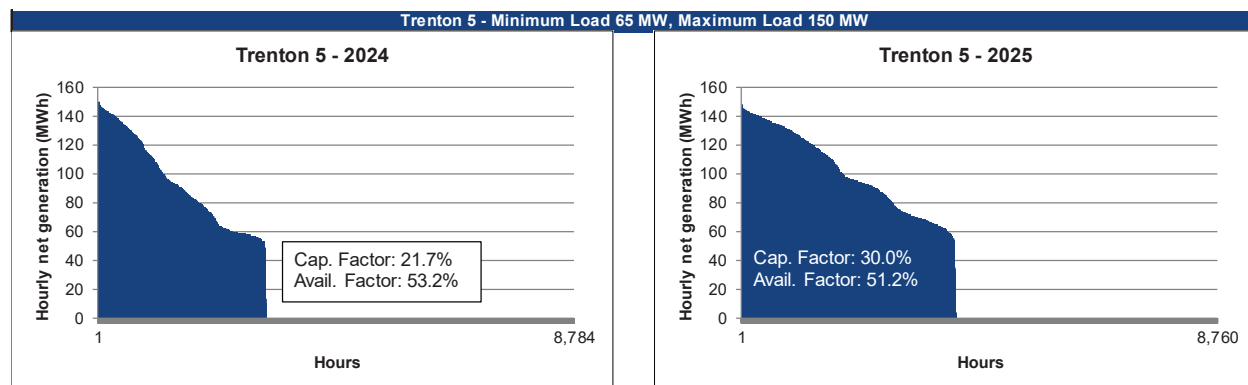


Figure XI-23: Trenton 6 Load

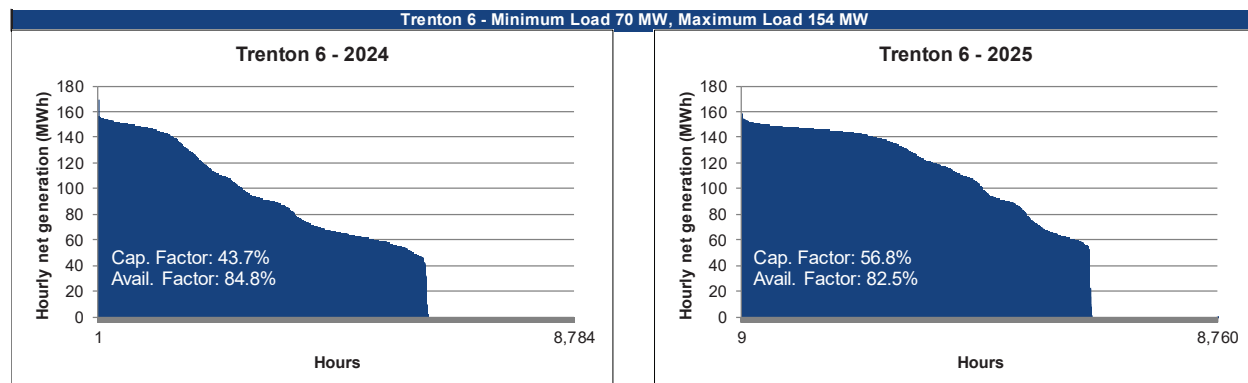


Figure XI-24: Tufts Cove 1 Load

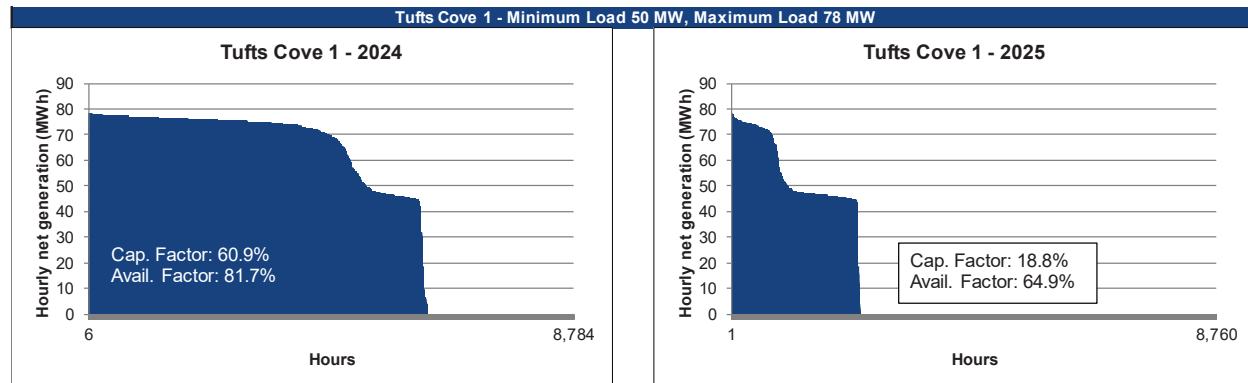
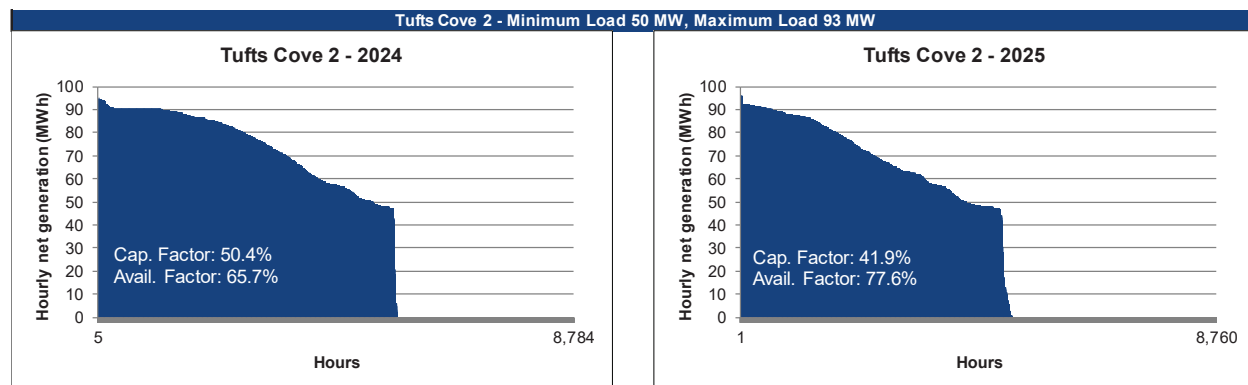


Figure XI-25: Tufts Cove 2 Load



Tufts Cove 3 - 2024

Hourly net generation (MWh)

Cap. Factor: 62.3%
Avail. Factor: 82.9%

Hours

Tufts Cove 3 - 2025

Hourly net generation (MWh)

Cap. Factor: 42.1%
Avail. Factor: 75.4%

Hours

XI.B.10.b. Start-up and Cycling Costs

[REDACTED] had the highest average cost per start-up in the audit period at \$ [REDACTED], \$ [REDACTED] and \$ [REDACTED] respectively. [REDACTED]

_____ The start-up costs for Tufts Cove are _____ and for all units except for Tufts Cove 1, substantially _____ than those for the solid-fuel units.

Figure XI-27: Start-up and cycling maintenance costs, 2024 and 2025

Unit	Number of Start-Ups (Cold, Warm, Hot)		Average cost per start-up	Total start-up costs	Total cycling and maintenance costs	Total start-up and cycling and maintenance costs
	2024	2025				
Lingan 1						
Lingan 2						
Lingan 3						
Lingan 4						
Point Aconi						
Point Tupper						
Trenton 5						
Trenton 6						
Tufts Cove 1						
Tufts Cove 2						
Tufts Cove 3						
Tufts Cove 4						
Tufts Cove 5						
Tufts Cove 6						
PT Biomass						
Burnside 1						
Burnside 2						
Burnside 3						
Burnside 4						
Victoria Junction 1						
Victoria Junction 2						
Tusket 1						
Total						

Frequent cycling of baseload units stresses the equipment and increases maintenance costs. NSPI reports cycling maintenance costs in the current audit period that are more than \$■ million less than in the prior audit period.

XI.B.11. Bates White 2022–2023 Recommendations

In the 2022-2023 Audit Report, BW made two recommendations relating to economic commitment and dispatch. These recommendations were addressed as follows:

Recommendation XI-1: NSPI should provide a detailed report that identifies and explains in detail how commitment and dispatch issues were addressed by the selected Outage Coordination and Economic Dispatch Optimization Solutions. The report should specifically address and explain at a minimum:

- a. what modelling enhancements were selected to minimize commitment and scheduling decisions made outside of PortOps and to reduce manual adjustments made to PortOps parameters,
- b. how exceptional dispatch information informed the choice of outage coordination and economic dispatch optimization solutions,
- c. how historical decisions made by the System Operator informed the real-time system optimization and enhanced processes selected,
- d. how RTED functionality is addressed by the selected outage coordination and economic dispatch optimization solutions,
- e. how the management of natural gas pressure, solid fuel supply, and natural gas pipeline positions are addressed by the selected outage coordination and economic dispatch optimization solutions,
- f. how the modelling and dispatch of PT Biomass is affected by the selected outage coordination and economic dispatch optimization solutions,
- g. what new tools to optimize PH Paper load in real time are contained within the selected outage coordination and economic dispatch optimization solutions,
- h. what new tools to optimize Wreck Cove in real time are contained within the selected outage coordination and economic dispatch optimization solutions,
- i. how reserve deficiencies will be managed by the new tools within the selected outage coordination and economic dispatch optimization solutions, and
- j. how tracking of dispatch decisions made by marketers and the System Operator will be done within the selected outage coordination and economic dispatch optimization solutions.

In its reply evidence,⁵⁷⁷ NSPI accepted this recommendation but provided no additional information or detail in its response. NSPI provided updates on its compliance approach to this recommendation in the NS Power Response to Undertakings filed on May 8, 2025 under the response to Undertaking U-22.⁵⁷⁸ The responses provided are high-level and forward-looking. These responses do not meet the recommendation for a detailed and comprehensive report that explains how the new functionality addresses (and does not address) outage, optimization, and dispatch issues identified in the current system. We renew our recommendation that NSPI provide a comprehensive report. **(Recommendation XI-2)**

⁵⁷⁷ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.24.1.

⁵⁷⁸ NSPI, Exhibit N-44(C), M11533, May 8, 2025, Undertaking U-22.

Recommendation XI-2: NSPI should retain the hourly system marginal cost data from the PortOps day ahead optimization to allow the evaluation of day ahead schedules at a future date.

In its reply evidence, NSPI accepted this recommendation, stating that it “will develop a process to retain the cost data used in the PortOps day ahead optimization.”⁵⁷⁹ In their February 2026 Update, NSPI confirmed that this data was being retained. Bates White reviewed this data as provided in DR 2-75 and concluded that NSPI has fully addressed this recommendation.

XI.C. Conclusions

Conclusion XI-1: NSPI, to its credit, was able to keep its system running reliably through the period following the cyber event. However, the loss of automation and information required for scheduling and dispatch would have inevitably resulted in a loss of efficiency and increased costs.

Conclusion XI-2: The processes that NSPI uses for committing, scheduling, and dispatching units were not changed during the period before the cyber event, January 1, 2024 through April 25, 2025. The concerns that we raised about these processes in prior audit reports remain intact for the 2024-2025 audit period. A new Outage Coordination Solution and Economic Dispatch Optimization Solution is expected to be implemented in 2026. **(Recommendation XI-1)**

Conclusion XI-3: In the period January 1, 2024 to April 24, 2025, when PortOps was functional, PortOps failed to operate correctly or could not produce a schedule in many instances.

Conclusion XI-4: The RTED functionality has limited usefulness as used by NSPI.

Conclusion XI-5: The commitment and scheduling plans, based on least-cost optimization using PortOps, were frequently manually adjusted to incorporate unmodelled constraints, or judgements by marketers or the NSPSO based on knowledge and experience. **(Recommendation XI-1)**

Conclusion XI-6: The dispatch of PH Biomass does not reflect the marginal cost of the unit in many hours because fuel costs and heat rates are imprecise or incorrect. However, the OBPS adjustment made the unit’s marginal cost economic in most hours.

Conclusion XI-7: Given the high number of hours that PHP load does not materialize because of equipment or process failures, NSPI’s conservative approach to count PHP’s load as operating reserves only in real time if needed by the NSPSO, is prudent.

⁵⁷⁹ NSPI, Exhibit N-3(C), M11533, September 13, 2024, section 2.24.1.

Conclusion XI-8: Langan 2 was kept online after it was called to service for system security reasons for long stretches of time. Once Langan 2 is brought on line, it is kept online for a period of time to allow thermal stresses to stabilize (typically a week). **(Recommendation XI-2)**

Conclusion XI-9: We find the day ahead system marginal costs and system lambda reported during a large portion of hours in 2024 were understated.

Conclusion XI-10: We find that GHG emissions have increased by 16% over 2023 levels, due to, among other factors, increased production from solid fuel units driven by OBPS and lower natural gas prices in 2025.

Conclusion XI-11: Low capacity factors of most units in NSPI's fleet may be indicative of potential inefficiencies. More efficient use of existing generation may be possible with the new Economic Dispatch Optimization Solution. **(Recommendation XI-1)**

XI.D. Recommendations

Recommendation XI-1: NSPI should be required to comply with 2022-2023 Recommendation XI-1 and provide a detailed and comprehensive report that explains how the new functionality in the Economic Dispatch Optimization and Outage Coordination Solutions address (or do not address) the outage, optimization, and dispatch issues identified in the current systems.

Recommendation XI-2: NSPI should develop a written set of criteria, to be approved by the Board, that must be met to keep Langan 2 operational once committed. Compliance with these criteria should be used by the Board when approving capital and operating costs for Langan 2.

XII. Power Purchases and Sales

XII.A. Background

NSPI's owned generation has historically provided the vast majority of power to NSPI's customers. For example, from 2013 through 2015, NSPI's generating fleet provided about 87.4% of all energy to NSPI's customers.⁵⁸⁰ The rest of NSPI's power needs is largely provided by unaffiliated third parties, as well as some affiliate-provided power from the Emera-owned Brooklyn Power facility. In addition, NSPI can export power to neighboring control areas, though export volumes have been low. In recent years, that trend has begun to change, with third-party power reaching █ percent of net system requirements in the prior audit period.⁵⁸¹ In this Audit Period, with the onset of substantial quantities of imports from Muskrat Falls, NSPI received about 36 percent of its power from third parties.⁵⁸²

The sources and terms of the third-party purchases vary. They can be long-term power purchases—such as multi-year power purchase agreements (“PPAs”), or single-month contracts resulting from month-ahead RFPs—or shorter term, including day-ahead and real-time hourly transactions. The purchases can be for economic purposes, reliability purposes, or driven by public policy, such as Nova Scotia's Renewable Electricity Standard (“RES”).

NSPI's Fuel Manual contemplates both power import and power export transactions. For example, section 13.1 of the Fuel Manual allows NSPI's energy marketers to conduct day-ahead and hour-ahead power purchases and sales,⁵⁸³ while section 13.3 dictates that NSPI undertake long-term power purchase agreements with the goal of securing “█,” sometimes through the use of competitive RFPs, along with █ arrangements.⁵⁸⁴

Power purchases (and sales) are important elements of a healthy electric utility. Buying power from third parties can have numerous benefits, including procuring power at a price lower than the utility's marginal system price and enjoying the benefits of electric energy without the costs and risks associated with rate-based utility generating assets. Selling power can also benefit customers, either through the sale of excess energy during periods of high wind output and low load, or simply when high prices in neighboring regions provide economic trade opportunities.

⁵⁸⁰ Data calculated from Liberty 2014-2015 Audit Report, page X-2.

⁵⁸¹ 2022-2023 Bates White Audit Report, page 312.

⁵⁸² Q4 2024 FAM Report, Q6; Q4 2025 FAM Report, Q6.

⁵⁸³ Fuel Manual Revision 14, section 13.1.

⁵⁸⁴ Fuel Manual Revision 14, section 13.3.

XII.B. Findings

We provide our findings below, separated into four areas. We begin with purchased power, which includes long-term purchases, term RFPs, and short-term purchases (i.e., day-ahead and real-time transactions). We next discuss power export sales, which are all short-term transactions. We then address all affiliate transactions, including those with Emera Energy, NSPEMI, Brooklyn Power, and NSPML. We conclude with a discussion of our previous audit recommendations related to power purchases and sales.

XII.B.1. Purchased Power

Over the two-year Audit Period, approximately 64.1% of NSPI's total MWhs were produced by NSPI-owned generation, while about 35.9% were generated by third-party power producers. Figure XII-1 below shows this data across both years of the Audit Period.

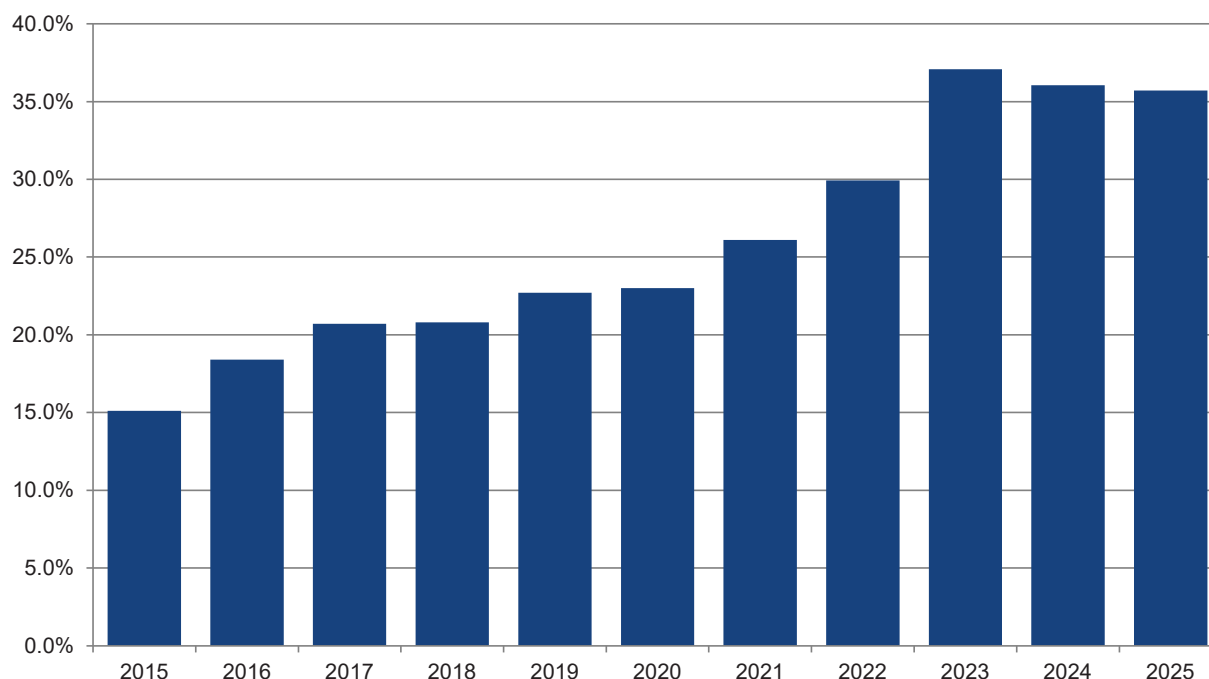
Figure XII-1: Ownership of Generation Serving NSPI Customers⁵⁸⁵

Generation Serving NSPI Customers (MWh)		
	2024	2025
NSPI-Owned Thermal Generation	6,309,911	6,520,644
NSPI-Owned Renewables	932,274	855,113
Third-Party Power	4,084,135	4,097,853
Total	11,326,320	11,473,610
Percentage Share of NSPI Generation	63.9%	64.3%
Percentage Share of Third-Party Power	36.1%	35.7%

Over the past ten years, the amount of energy being provided by third parties has grown (though it has declined slightly from a peak in 2023), from 15.1% in 2015 to 35.7% in 2025. This trend is shown in Figure XII-2 below.

⁵⁸⁵ Q4 2024 FAM Report, Q6; Q4 2025 FAM Report, Q6.

Figure XII-2: Percentage of Third-Party-Provided Energy to NSPI Customers (2015–2025)⁵⁸⁶



The sources—and costs—of this third-party power vary. NSPI reports its third-party power purchases in five categories:

- a. **Imports:** Imported energy is energy that originates from neighboring control areas, and is the broadest category. NSPI is directly interconnected with the New Brunswick system and the Newfoundland and Labrador system. For imports over the New Brunswick tie, power can come from New Brunswick, ISO New England, or Quebec. The interconnection with Newfoundland and Labrador allows NSPI to receive energy from Muskrat Falls, including the Nova Scotia Block (“NS Block”) provided pursuant to the Energy and Capacity Agreement with Newfoundland and Labrador Hydro (“NLH”), Surplus Energy provided pursuant to the Energy Access Agreement with NLH, and additional bilateral transactions. The purpose of NSPI’s import transactions is for (a) economics, i.e., importing power when it is cheaper to do so than to produce or procure energy domestically, (b) for reliability, i.e., when NSPI’s generation reserves are at low levels and additional imported energy would shore up the reliability of NSPI’s system, or (c) meeting contractual agreements, such as the Energy and Capacity Agreement with NLH, which calls for certain amounts of firm energy to be provided at certain times in the year. (We address Muskrat Falls energy from NLH later in this chapter.)

⁵⁸⁶ Data compiled from NSPI FAM Quarterly Reports.

- b. **IPP Wind:** NSPI lists 26 independent power producer (“IPP”) owned wind facilities that provided power to NSPI during the Audit Period, with three such projects co-owned by NSPI and IPPs.⁵⁸⁷ IPP wind prices are fixed pursuant to power purchase agreements with NSPI; thus, NSPI is required to “take or pay” for the power provided by these resources. It does not curtail wind generators for economic reasons but can curtail them for reliability reasons. In those cases, all wind generators are treated the same, regardless of their ownership or PPA arrangement: that is, their owners are not paid for such curtailments, and curtailment occurs in a fair, equitable manner.⁵⁸⁸
- c. **IPP Other:** NSPI lists seven IPP-owned non-wind supply resources, three of which provided power to NSPI during the Audit Period.⁵⁸⁹ IPP non-wind prices are fixed pursuant to power purchase agreements with NSPI. IPP Wind prices averaged \$[REDACTED]/MWh during the Audit Period.⁵⁹⁰ IPP other prices averaged \$[REDACTED]/MWh during the Audit Period.⁵⁹¹
- d. **COMFIT:** The COMFIT Program was a program that the government of Nova Scotia offered to enable community organizations to provide renewable electricity generation. No longer accepting new resources⁵⁹² but still allowing existing resources to extend their COMFIT agreements, the program allowed generators including hydro, small wind (< 50 kW), large wind, and biomass/biogas. COMFIT rates are fixed and defined by the Nova Scotia Department of Energy⁵⁹³ pursuant to power purchase agreements with NSPI. NSPI listed 79 such agreements for the Audit Period.⁵⁹⁴ COMFIT prices averaged \$135.10/MWh during the Audit Period.⁵⁹⁵
- e. **COMSOLAR:** The Community Solar Program (“COMSOLAR”) is a program implemented by the Nova Scotia Department of Energy. The program allows for investments by community organizations in solar PV arrays between 0.5 and 10 MW in exchange for 25-year

⁵⁸⁷ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁸⁸ NSPI can curtail wind generators due to local transmission constraints or light load conditions. For the former, NSPI curtails resources with non-network transmission service first. For the latter, NSPI curtails generators by 33% (using a rotational list) until the needed reduction is achieved.

⁵⁸⁹ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁹⁰ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁹¹ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁹² Government of Nova Scotia, “Minister Announces COMFIT Review Results, End to Program,” August 6, 2015, *available at* <https://novascotia.ca/news/release/?id=20150806001>.

⁵⁹³ Nova Scotia Department of Energy, “Community Feed-In Tariff Program Facts,” *available at* https://energy.novascotia.ca/sites/default/files/comfit_facts.pdf.

⁵⁹⁴ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁹⁵ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

PPAs with NSPI at a fixed price.⁵⁹⁶ NSPI listed 62 COMSOLAR agreements in effect during the Audit Period.⁵⁹⁷ COMSOLAR prices averaged \$ [REDACTED]/MWh during the Audit Period.⁵⁹⁸

We provide our findings across four types of purchased power transactions. We begin with long-term purchases (which includes IPP Wind, IPP Non-Wind, COMFIT, and COMSOLAR), followed by term RFPs, then a discussion on short-term transactions (both imports and exports), and finally a review of all imports over the Maritime Link from Newfoundland and Labrador.

XII.B.1.a. Long-Term Purchases

NSPI's Fuel Manual states that NSPI will undertake longer-term power purchases "[REDACTED] [REDACTED]"⁵⁹⁹ The Fuel Manual notes that [REDACTED] including [REDACTED] [REDACTED]" all with the purpose of attempting to "realize value."⁶⁰⁰

Figure XII-3 shows that COMFIT resources cost, on average, about \$135.10/MWh during the Audit Period and can cost several hundred dollars per MWh depending on the type of COMFIT resource. As noted above, COMFIT rates are set by the Nova Scotia Department of Energy and are not subject to negotiation. In terms of COMFIT quantities, NSPI received 995,424 MWh from COMFIT resources, 3.2 percent below the forecasted amount of 1,028,689.⁶⁰¹ Figure XII-3 contains more detail about the COMFIT resources, showing the output and costs for each COMFIT resource during the Audit Period. No new COMFIT contracts were executed during the Audit Period.

⁵⁹⁶ Government of Nova Scotia, "Nova Scotia Community SOLAR Program Guide," available at: <https://novascotia.ca/programs/community-solar/cs-program-guide.pdf>.

⁵⁹⁷ 2025 FAM Annual Report, A5.

⁵⁹⁸ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁵⁹⁹ Fuel Manual Revision 14, section 13.3.

⁶⁰⁰ Fuel Manual Revision 14, section 13.3.

⁶⁰¹ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

Figure XII-3: Output, Cost of COMFIT Resources (by project)⁶⁰²

Counterparty	Location	Capacity (MW)	2024 MWh	2025 MWh	Cost (2024)	Cost (2025)	Total Cost (\$/MWh)
Colchester-Cumberland Wind Field	Spiddle Hill (Large Wind) COMFIT 072	0.80	2,661	2,718	\$348,545	\$355,995	\$131.00
Town of New Glasgow	Town of New Glasgow	0.05	22	32	\$11,106	\$16,020	\$499.00
Pockwock Wind Limited Partnership	Chebucto Pockwock Community Wind Project	10.00	30,348	31,940	\$3,975,594	\$4,184,146	\$131.00
Watts Wind II Limited Partnership	New Glasgow	6.40	19,901	22,115	\$2,607,005	\$2,897,039	\$131.00
Municipality of the District of Guysborough	Melford	0.10	77	-1	\$38,270	-\$516	\$499.00
Municipality of the District of Guysborough	Goldboro	0.15	24	-2	\$12,022	-\$863	\$499.00
Universite Sainte-Anne	Church Point	0.05	42	44	\$21,035	\$22,020	\$499.00
Municipality of the County of Pictou	MOPC Riverton Small Wind COMFIT, Phase 1	0.15	54	57	\$27,192	\$28,538	\$499.00
Municipality of the District of Shelburne	Sandy Point Road	0.05	29	9	\$14,312	\$4,308	\$499.00
Avondale Community Wind Park Limited Partnership	Avondale Community Wind Park	1.60	6,947	6,705	\$875,230	\$878,324	\$128.45
HG Wind Limited Partnership	Gaetz Brook Wind Farm	2.30	7,234	6,958	\$947,651	\$911,455	\$0.00
Colchester-Cumberland Wind Field Inc.	Spiddle Hill (Small Wind)	0.10	198	181	\$98,907	\$90,405	\$499.00
Town of Amherst	Fort Lawrence	0.05	6	44	\$3,030	\$21,733	\$499.00
Municipality of the District of Chester	Kaizer Meadow	2.00	5,667	5,728	\$742,348	\$750,339	\$131.00
ScotianWEB Limited Partnership	Isle Madame Community Wind Project	1.99	6,376	5,830	\$835,262	\$763,793	\$131.00
Affinity Renewables Inc.	Fitzpatrick	1.40	4,727	4,743	\$619,234	\$621,313	\$131.00
Affinity Wind LP	Kemptown	4.99	16,310	16,212	\$2,136,662	\$2,123,772	\$131.00
Affinity Wind LP	Greenfield	3.20	9,276	9,347	\$1,215,218	\$1,224,408	\$131.00
Affinity Wind LP	Limerock	4.99	17,405	18,043	\$2,280,075	\$2,363,594	\$131.00
Celtic Current Limited Partnership	Bateston Community Wind Project	2.30	8,632	9,004	\$1,130,730	\$1,179,556	\$131.00
Celtic Current Limited Partnership	Point Aconi Community Wind Project	2.35	5,932	6,313	\$766,256	\$827,010	\$130.11
Celtic Current Limited Partnership	Cheticamp Community Wind Project	0.90	2,002	1,905	\$262,298	\$249,595	\$131.00
Celtic Current Limited Partnership	Mulgrave Community Wind Project	2.30	7,588	7,578	\$993,973	\$992,675	\$131.00
ScotianWEB Limited Partnership	St. Rose Community	1.99	6,608	7,337	\$917,692	\$909,020	\$131.00
ScotianWEB Limited Partnership	Little River Community	1.99	7,639	7,664	\$952,561	\$1,003,953	\$127.85
ScotianWEB Limited Partnership	Martock Ridge Community Wind Project	6.00	20,470	20,804	\$2,681,576	\$2,725,358	\$131.00
ScotianWEB Limited Partnership	Nine Mile River Community Wind Project	4.00	13,375	14,237	\$1,752,170	\$1,865,002	\$131.00
Watts Wind II Limited Partnership	Wedgeport	1.68	4,541	5,875	\$594,928	\$769,571	\$131.00
Whynotts Wind Limited Partnership	Whynotts Community	4.00	12,072	11,229	\$1,581,441	\$1,471,042	\$131.00
Truro Heights Wind Limited Partnership	Truro Heights	4.00	13,421	13,840	\$1,758,125	\$1,813,071	\$131.00
Truro-Millbrook Wind Limited Partnership	Truro - Millbrook	6.00	21,345	21,820	\$2,796,180	\$2,858,383	\$131.00
BA Wind Limited Partnership (Natural Forces Wind Inc.)	Aulds Mountain Wind Farm	4.60	16,750	17,882	\$2,194,264	\$2,342,560	\$131.00
Valley Region Solid Waste Resource Management Authority	Kentville	0.05	31	37	\$15,401	\$18,275	\$499.00
HG Wind Limited Partnership (Natural Forces Wind Inc.)	Hillside-Boularderie Wind Farm	4.00	13,537	12,970	\$1,773,329	\$1,699,067	\$131.00
Windmill Holsteins Inc.	Shubenacadie	0.50	2,244	3,621	\$447,037	\$723,972	\$199.65
ScotianWEB Limited Partnership	North Beaver Bank Community Wind Project	8.00	29,779	29,452	\$3,901,112	\$3,858,154	\$131.00
ScotianWEB Limited Partnership	Black Pond Community Wind Project	1.99	7,454	7,449	\$976,507	\$975,820	\$131.00
Watts Wind II Limited Partnership	Barrington (Shag Harbour)	3.20	9,807	9,835	\$1,284,699	\$1,288,351	\$131.00
Halifax Regional Water Commission	Bedford	0.03	141	153	\$19,724	\$21,471	\$140.00
Municipality of the County of Pictou	MOPC Riverton Small Wind COMFIT, Phase 2	0.15	-6	8	-\$3,190	\$4,220	\$499.00
Municipality of the District of Barrington	MOB Barrington Renewable Energy Project	0.05	6	-1	\$2,998	-\$271	\$499.00
EM Wind Limited Partnership	Barrachois Wind Farm	4.00	12,946	12,976	\$1,695,957	\$1,699,810	\$131.00
Gardiner Mines Wind Farm Limited Partnership	Gardiner Mines Wind Farm COMFIT 212	2.30	6,135	5,930	\$803,743	\$776,865	\$131.00
Gardiner Mines Wind Farm Limited Partnership	Gardiner Mines Wind Farm COMFIT 212A	3.10	10,530	10,424	\$1,379,372	\$1,365,531	\$131.00
Colchester Cumberland Wind Field Inc.	Tatamagouche	0.05	155	-3	\$77,143	-\$1,267	\$499.00
Watts Wind III LP	Ketch Harbour	4.60	12,753	14,401	\$1,670,640	\$1,886,493	\$131.00
Watts Wind III LP	Porters Lake	3.20	7,713	8,190	\$1,010,363	\$1,072,850	\$131.00
Municipality of the County of Colchester	Kemptown - Colchester Bafell Facility COMFIT 401	0.05	83	98	\$41,291	\$48,817	\$499.00
Municipality of the County of Colchester	Kemptown - Colchester Bafell Facility COMFIT 402	0.05	0	0	-\$10	\$0	\$499.00
Avondale Community Wind Park Limited Partnership	Avondale Community Wind Park COMFIT 164	0.05	105	114	\$52,332	\$57,012	\$499.00
Avondale Community Wind Park Limited Partnership	Avondale COMFIT 239	0.05	161	154	\$80,405	\$77,031	\$499.00
Port Hood & District Rec Commission	Cheticamp (COMFIT 284)	0.05	137	131	\$68,402	\$65,225	\$499.00
Celtic Current - Mulgrave	Mulgrave (COMFIT 286)	0.05	132	136	\$65,736	\$67,985	\$499.00
Port Hood & District Rec Commission - Cheticamp	Cheticamp (COMFIT 287)	0.05	156	155	\$77,942	\$77,314	\$499.00
Celtic Current - Mulgrave	Mulgrave (COMFIT 288)	0.05	151	146	\$75,402	\$72,990	\$499.00
Municipality of the District of Yarmouth	Rose Road (Wellington) COMFIT 370	0.05	148	135	\$74,025	\$67,267	\$499.00
Municipality of the District of Yarmouth	Rose Road (Wellington) COMFIT 371	0.05	129	126	\$64,374	\$62,931	\$499.00
Mikmaq-Wind4All Communities Limited Partnership	Amherst Community Wind Farm COMFIT 255	6.00	18,985	18,958	\$2,487,019	\$2,483,561	\$131.00
ScotianWEB II Limited Partnership	Brenton Community Wind Project	1.99	6,438	6,935	\$843,424	\$908,447	\$131.00
ScotianWEB II Limited Partnership	Hardwood Lands Community Wind	6.00	17,659	17,645	\$2,313,355	\$2,311,469	\$131.00
ScotianWEB II Limited Partnership	Walton Community Wind Project	1.99	6,113	5,743	\$800,848	\$752,396	\$131.00
ScotianWEB II Limited Partnership	Baddeck Community Wind Project	1.70	5,496	5,604	\$719,953	\$734,102	\$131.00
Chebucto Terence Bay Wind Field Ltd.	Chebucto Terence Bay Community Wind Farm	7.05	18,972	18,577	\$2,485,350	\$2,433,594	\$131.00
Mikmaq-Wind4All Communities Limited Partnership	Pictou Landing First Nation COMFIT 256	1.60	6,071	6,160	\$795,291	\$806,919	\$131.00
Municipality of the District of Digby	859 Culloden Rd COMFIT 372	0.05	178	167	\$88,902	\$83,361	\$499.00
Liverpool Wind Energy Storage Project Inc.	Liverpool Wind Energy Storage Project COMFIT 326	3.60	10,496	10,990	\$1,374,913	\$1,439,673	\$131.00
Celtic Current Limited Partnership	New Victoria COMFIT 191	2.35	7,660	7,490	\$979,153	\$981,164	\$129.39
Celtic Current Limited Partnership	Cheticamp COMFIT 365	0.05	138	159	\$69,090	\$79,109	\$499.00
Celtic Current Limited Partnership	Cheticamp COMFIT 366	0.05	152	135	\$75,974	\$67,517	\$499.00
Celtic Current Limited Partnership	Point Aconi COMFIT 368	0.05	73	65	\$36,205	\$32,285	\$499.00
Celtic Current Limited Partnership	Point Aconi COMFIT 369	0.05	114	126	\$57,129	\$62,818	\$499.00
Chestico Museum and Historical Society	Cheticamp COMFIT 391	0.05	128	125	\$63,797	\$62,395	\$499.00
Chestico Museum and Historical Society	Cheticamp COMFIT 395	0.05	136	110	\$67,669	\$54,964	\$499.00
Dalhousie University	363- Dalhousie Truro Biomass	1.00	5,866	4,602	\$1,168,541	\$919,652	\$199.48
Northumberland Wind Field Inc.	309- The Northumberland Wind Field Inc. - Mulgrave	0.05	192	235	\$96,006	\$117,257	\$499.00
Northumberland Wind Field Inc.	313- The Northumberland Wind Field Inc. - Pictou	0.05	115	176	\$57,406	\$87,878	\$499.00
Northumberland Wind Field Inc.	394- The Northumberland Wind Field Inc. - Fitzpatrick	0.05	176	120	\$87,811	\$59,762	\$499.00
TE Boyle Farm and Forestry Ltd.	361- TE Boyle Farm & Forestry	0.50	2,005	1,623	\$399,452	\$324,603	\$199.58
Courthouse Hill Energy Limited	310- Courthouse Hill Energy	0.50	3,849	3,733	\$766,665	\$747,778	\$199.73
Total COMFIT		152.98	493,121	502,303	\$66,679,579	\$67,799,230	\$135.10

Also included in this Audit Period were COMSOLAR projects. During the Audit Period, NSPI executed two new COMSOLAR agreements, bringing the total COMSOLAR agreements to 62 and

⁶⁰² 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5. In some cases, the “Total Cost” column differs slightly from the provincially established PPA price, due to rounding.

totaling 3.85 MW, all of which produced at least some output during the Audit Period. Total output was [REDACTED] MWh.⁶⁰³ Prices are high, varying between \$[REDACTED]/MWh and \$[REDACTED]/MWh for most PPAs, with one reaching almost \$[REDACTED]/MWh. PPA prices were determined by a process administered by Clean Nova Scotia Foundation.⁶⁰⁴ There were no instances of force majeure and no terminated COMSOLAR PPAs in the Audit Period.⁶⁰⁵

⁶⁰³ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁶⁰⁴ 2022-2023 Bates White Audit Report, page 317.

⁶⁰⁵ Quarterly FAM Reports, “Q3” and “Q4”.

Figure XII-4: Output, Cost of COMSOLAR Resources (by project)⁶⁰⁶

Counterparty	Location	Capacity (MW)	2024 MWh	2025 MWh	Cost (2024)	Cost (2025)	Total Cost (\$/MWh)
Plymouth Community	Plymouth Community	0.02					
Hospice Halifax	Hospice Halifax	0.01					
Glooscap Energy	Glooscap Landing	0.02					
Glooscap Energy	Glooscap Energy	0.07					
Town of Antigonish	Antigonish Water Treatment Plant	0.05					
Municipality of the District of Yarmouth	Room/CSC Building	0.05					
Municipality of the District of Argyle	West Pubnico Water Treatment	0.02					
Municipality of the District of Argyle	West Pubnico Fire Department	0.05					
Nova Scotia Community College	Ivany Campus	0.04					
Nova Scotia Community College	Shelburne Campus	0.08					
Nova Scotia Community College	Strait Campus	0.08					
Nova Scotia Community College	Lawrencebown Campus	0.08					
Hope for Wildlife Society	Hope for Wildlife	0.03					
Hope for Wildlife Society	Hope for Wildlife #036	0.07					
Town of Yarmouth	Yarmouth Mariners Centre	0.05					
Town of Yarmouth	Public Works Facility	0.02					
Town of Yarmouth	Yarmouth Waste Transfer Plant	0.05					
Knox United Church	Knox United Church	0.04					
Municipality of the County of Colchester	Don Henderson Memorial Sportsplex	0.07					
Parrsboro Band Association	Parrsboro Band Hall	0.04					
Atlantic School of Theology	Atlantic School of Theology	0.05					
Town of Wolfville	Town of Wolfville	0.04					
Cape Breton University	CBU #014	0.05					
Cape Breton University	CBU #015	0.05					
Cape Breton University	CBU #016	0.05					
Municipality of the District of Colchester	Rath Eastlink Community Centre Solar	0.07					
Fundy Ocean Research Center for Energy	Fundy Ocean Research Center for Energy	0.03					
Municipality of the County of Cumberland Solar	Cumberland #026	0.07					
Sacred Heart School of Halifax	Sacred Heart School of Halifax	0.05					
East River Valley Fire Department	East River Valley Fire Department	0.02					
Church of Christ	Church of Christ	0.02					
Rockingham Pastoral Charge Solar	Rockingham Pastoral Charge Solar	0.06					
Town of Amherst	Town of Amherst	0.07					
St. Luke's United Church, Pastoral Charge	St. Luke's United Church, Pastoral Charge	0.04					
Halifax water	Halifax water	0.08					
Village of Canning	Village of Canning	0.07					
Memberbou First Nation	Memberbou First Nation	0.07					
Paq'inkek Mi'kmaw Nation	Paq'inkek Mi'kmaw Nation	0.07					
Eskasoni First Nation	Eskasoni First Nation	0.07					
Millbrook First Nation	Millbrook First Nation	0.07					
St. Josephs Parish Centre	St. Josephs Parish Centre	0.01					
Annapolis Valley First Nation	Annapolis Valley First Nation	0.07					
Pollotek First Nation	Pollotek First Nation	0.07					
Acadia First Nation	Acadia First Nation	0.07					
Municipality of the County of Antigonish	Antigonish Public Works	0.07					
Municipality of the County of Kings	Municipality of the County of Kings	0.07					
The Trustees of the First Baptist Church	First Baptist Church	0.08					
Shambhala Canada Society	Shambhala Canada Society	0.02					
Pictou Landing First Nation	Pictou Landing First Nation	0.07					
Town of Stewiacke	Town of Stewiacke	0.07					
Municipality of the County of Cumberland Solar	Cumberland #064	0.05					
Municipality of the County of Cumberland Solar	Cumberland #052	0.07					
Municipality of the County of Cumberland Solar	Cumberland #062	0.07					
Ecology Action Centre	Ecology Action Centre	0.01					
Cape Breton Christian Education and Service Association	Cape Breton Christian Education	0.08					
Municipality of the District of Argyle	Wedgeport Fire Department	0.07					
Town of Amherst	Amherst Firehall	0.05					
Town of Amherst	1695 Highway 1	0.05					
Universite Sainte-Anne	Lunenburg	0.08					
Nova Scotia Community College	Grand Passage	0.08					
Bayside Development	Alton	0.07					
Pine Tree Park Estates	Sydney	0.56					
Total COMSOLAR		3.85					

Non-Wind IPP costs per MWh are also high, averaging \$ [REDACTED]/MWh over the Audit Period. Figure XII-5 provides further details on the output and cost of non-wind IPP resources over the Audit Period. The non-wind IPP resources provided [REDACTED] MWh during the Audit Period, [REDACTED] % below NSPI's forecast.⁶⁰⁷

⁶⁰⁶ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁶⁰⁷ 2024 FAM Annual Report, A5 and A5(2); 2025 FAM Annual Report, A5 and A5(2).

Figure XII-5: Output, Cost of Non-Wind IPP (by Project)⁶⁰⁸

Counterparty	Location	Capacity (MW)	2024 MWh	2025 MWh	Cost (2024)	Cost (2025)	Total Cost (\$/MWh)

During the Audit Period, there were three non-wind projects which NSPI either executed new PPAs or extended existing PPAs:

- New Dawn Enterprises Solar PPA:** On June 27, 2024, NSPI received a letter from the Minister of Natural Resources and Renewables (“Minister”) informing NSPI that the Minister “approved New Dawn Enterprises’ Pine Tree Park Estates Solar Garden to produce [REDACTED] MWh of annual electricity at \$ [REDACTED] /MWh for sale to Nova Scotia Power under the Community Solar Program.” The Minister indicated that “the approval of this project has come before the Power Purchase Agreement associated with the program is available,” and thus NSPI should “take what actions are necessary and reasonable to ensure that New Dawn Enterprises is compensated for supplied energy in a manner consistent with the intent of the program and [the Minister’s] decision, until such time as [the Minister] can supply both parties with a Power Purchase Agreement.” In response to the Minister’s letter, NSPI developed a commercial arrangement with New Dawn Enterprises that applied from the commercial operations date of the project (December 1, 2024) through the date on which the Minister-provided PPA became effective (February 28, 2025). The short-term arrangement called for a price that matched the PPA (\$ [REDACTED] /MWh). In all, NSPI received [REDACTED] MWh from the facility at a total cost of \$ [REDACTED] (not including HST), or \$ [REDACTED] /MWh.
- [REDACTED] PPA Extension:** In August 2024, NSPI extended its existing PPA with [REDACTED] from September 1, 2024 through May 31, 2027 for [REDACTED] GWh of energy over that period at a forecasted average PPA price of \$ [REDACTED] /MWh, for a total forecasted cost of \$ [REDACTED] over that 33-month term. The original PPA, which had a 30-year term, was set to expire on August 31, 2024. The extension continues the terms of the original PPA.⁶⁰⁹
- [REDACTED] PPA Extension:** On September 17, 2024, NSPI executed a 10-year extension of its existing PPA with [REDACTED] MW combined heat and power plant⁶¹⁰ that burns

⁶⁰⁸ 2024 FAM Annual Report, A5 and A5(2); 2025 FAM Annual Report, A5.and A5(2).

⁶⁰⁹ [REDACTED] - 20240831 Extension Agreement.”

⁶¹⁰ “[REDACTED] - 20240901 Third Amending Agreement.”

wood waste produced from the ██████ sawmill, chipping plant, and planner mill operations. The PPA price is fixed at \$█████/MWh for the entire term (September 1, 2024 through August 31, 2024).⁶¹¹ To evaluate the economics of this contract extension, NSPI compared its cost to the cost of replacement capacity and to existing biomass generation. Specifically, NSPI compared the cost of the unit to a COMFIT alternative and the cost of replacement capacity, which included a third-party estimate of a frame combustion turbine, plus avoided fuel and OBPS costs. The ██████ PPA extension was evaluated at a similar 10-year net present value as the alternatives.

NSPI's decisions to extend ██████ and ██████ PPAs were supported by alternatives analysis and reasonably attempted to capture the costs and benefits of the resources and their alternatives. It would be preferable for resources like these (and their alternatives) to compete to provide renewable energy to NSPI, not be subject to one-off, alternatives analysis comparisons. Going forward, the IESO will be responsible for this function and will hopefully embark upon improvements to introduce best practices competitive procurement to the province for the benefit of FAM customers. As such, we do not include a recommendation on this point.

Figure XII-6 below shows NSPI's IPP Wind purchases during the Audit Period, which averaged \$█████/MWh. Overall, IPP wind produced 1,843,109 MWh over the Audit Period, which was ██████% below forecast.⁶¹²

Figure XII-6: Output, Cost of IPP Wind (by Source)⁶¹³

Counterparty	Location	Capacity (MW)	2024 MWh	2025 MWh	Cost (2024)	Cost (2025)	Total Cost (\$/MWh)
[REDACTED]							

⁶¹¹ "██████████ - 20240901 Third Amending Agreement," item 4.

⁶¹² 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

⁶¹³ 2024 FAM Annual Report, A5; 2025 FAM Annual Report, A5.

During the Audit Period, NSPI executed several new PPAs with third-party wind projects. Details of those PPAs are shown in Figure XII-7 below.

Figure XII-7: New Wind PPAs

Wind PPA	Counterparty	Schedule COD	Expiration Date	Project Size (MW)	Cost per MWh
		December 15, 2026	25 years from commencement date	130.5	
		December 31, 2028	25 years from commencement date	150	
		December 31, 2028	25 years from commencement date	112	
		March 31, 2027	25 years from commencement date	12.6	
		December 31, 2026	25 years from commencement date	90 or 148.5	

We provide additional details of these agreements as follows:

- Green Choice PPAs:** In June 2025, NSPI entered into two long-term PPAs under the Green Choice Program with two separate wind projects. On June 6, 2025, NSPI entered into a 25-year PPA with [REDACTED] Inc. for the [REDACTED] project, a 150 MW wind project.⁶¹⁴ Under the PPA, NSPI will pay \$ [REDACTED] /MWh for energy from the project, which is expected to reach commercial operations on December 31, 2028.⁶¹⁵ On June 13, 2025, NSPI entered into an additional 25-year PPA with [REDACTED] Wind Inc. for the WEB Sugar Maple Wind project, a 112 MW facility.⁶¹⁶ NSPI will pay \$ [REDACTED] /MWh for output from the project, which is also expected to reach commercial operations on December 31, 2028.⁶¹⁷ In both cases, the PPAs for the projects were issued by a Procurement Administrator appointed by the Minister of Energy in relation to the Green Choice Program pursuant to Section 4B of the *Electricity Act* of 2004. Under the legislation, NSPI does not have discretion to decline to execute and perform a contract that is issued by the Minister or Procurement Administrator thereunder. Coho Climate Advisors LLC (“Coho”) was the Procurement Administrator, and Coho consulted NSPI in the development of the PPAs. NSPI suggested a form of PPA that was similar to that used in the Rate Base Procurement since that PPA had been approved by the Board. The Green Choice PPAs were reviewed and approved by the Board in matter M11455.

⁶¹⁴ [REDACTED] - 20250606 GCP PPA.”

⁶¹⁵ [REDACTED] - 20250606 GCP PPA.”

⁶¹⁶ [REDACTED] -220250613 GCP PPA.”

⁶¹⁷ [REDACTED] -220250613 GCP PPA.”

- **Goose Harbour PPA and PSA:** On October 24, 2024, the Minister issued a PPA between Port Hawkesbury Paper Wind Ltd. and NSPI, as well as a Sale Agreement (“PSA”) between NSPI and Port Hawkesbury Paper Limited Partnership, related to the development of the Goose Harbour Lake Wind Farm project (“Goose Harbour”). The Minister stated: “All three parties should now proceed to execute these agreements as attached.” On November 2, 2024, NSPI executed the two agreements as directed.⁶¹⁸ NSPI indicated that since 2023 it has been providing advice to the Province and to PHP on the development of the PPA and PSA. NSPI stated that the Minister weighed input from NSPI and PHP and ultimately exercised his discretion in determining the final form of the PPA and PSA pursuant to Section 24(5) of the Electricity Act. NSPI indicated that in order to comply with the statutory requirements of the Electricity Act, it was obligated to execute the PPA and PSA as issued by the Minister. Under the 25-year PPA, NSPI purchases the entire net output of Goose Harbour from PHP Wind Ltd. at a price of \$[REDACTED]/MWh.⁶¹⁹ Under the 25-year PSA, PHP buys all output of Goose Harbour at that same price of \$[REDACTED]/MWh, plus a “Sales Agreement Fee” of \$[REDACTED]/MWh or \$[REDACTED]/MWh, with the higher fee value applicable if PHP’s actual annual energy use is less than [REDACTED] MWh.⁶²⁰
- **PPAs, PSAs for Minas Highlands Wind, Mersey River Wind:** On August 19, 2025, the Minister issued a PPA between Minas Highlands Wind Ltd. and NSPI, plus a PSA between NSPI and Minas Basin Pulp and Power Company Ltd. The Minister’s letter stated: “All three parties should now proceed to execute these agreements as attached.” That same day, the Minister issued a separate letter directing NSPI to execute a PPA with Mersey River Wind Inc. for the Mersey River Wind Farm., On that same day (August 19, 2025), NSPI executed all three agreements as directed.⁶²¹ In the case of both projects, the agreements’ terms and conditions were entirely determined by the Minister pursuant to s. 4AA of the Electricity Act of 2004, though NSPI was consulted on the agreements for both projects. NSPI explained that under the legislation, NSPI does not have discretion to decline to execute and perform a contract that is issued by the Minister thereunder. Under the Minas PPA, Minas’ 12.6 MW wind project (commercial operations date: March 31, 2027) will sell power to NSPI for 25 years at \$[REDACTED]/MWh,⁶²² while under the PSA, NSPI will sell that same power to Minas Basin Pulp and Paper Company for \$[REDACTED]/MWh plus a Sales Agreement Fee of \$[REDACTED]/MWh.⁶²³ Under the 25-year PPA with Mersey River Wind (expected commercial operations date: December 31, 2026), NSPI will buy the

⁶¹⁸ “PHP - 20241102 PPA;” “PHP - 20241102 - Power Sales Agreement.”

⁶¹⁹ “PHP - 20241102 PPA.”

⁶²⁰ “PHP - 20241102 - Power Sales Agreement.”

⁶²¹ “Minas - 20250819 PPA Minas Highlands;” “Minas - 20250819 Power Sales Agreement;” “Mersey River Wind Inc. - 20250819 Power Purchase Agreement.”

⁶²² “Minas - 20250819 PPA Minas Highlands.”

⁶²³ “Minas - 20250819 Power Sales Agreement.”

project's output at \$ [REDACTED]/MWh.⁶²⁴ The size of the project will be either 90 MW or 148.5 MW, depending on whether the project owner pursues one or two phases of the project.⁶²⁵

We requested information regarding whether these two projects participated in the Rate Base Procurement, given that the PPA prices in these contracts (\$ [REDACTED]/MWh) are considerably higher than those in the Rate Base Procurement PPAs (\$ [REDACTED]/MWh). NSPI indicated that it was not privy to that information. We also reviewed one key aspect of the Mersey River Wind project, namely, that it already had an off-taker for its output, [REDACTED], a [REDACTED]. NSPI explained that its PPA with Mersey River Wind is conditional on the project disengaging from its offtake agreements with [REDACTED] due to default by [REDACTED]. When we asked if NSPI is serving as a backstop purchaser for the Mersey River Wind project, NSPI agreed.

XII.B.1.b. Term RFPs

NSPI has historically relied in part upon RFPs for imported power across the New Brunswick-Nova Scotia intertie. With the energization of the Maritime Link in 2018, power could also be imported over that intertie with Newfoundland. These RFPs typically have a term of one month (though sometimes multiple months) and are typically issued one month in advance of power flow.

During the Audit Period, NSPI issued [REDACTED] RFPs for purchased power. [REDACTED] were RFPs issued to comply with the terms of the EAA. We address the results of these [REDACTED] RFPs in section XII.B.1.d.iii below.

XII.B.1.c. Short-Term Purchases

The Fuel Manual allows the NSPI and NSPEMI Energy Marketers to make day-ahead and hour-ahead power purchases and sales.⁶²⁶ Specifically, the Fuel Manual notes that NSPI's energy marketers will "[REDACTED]".⁶²⁷ The Fuel Manual requires the energy marketing team at NSPI to conform to NSPI's Risk Management Policy and Credit Policy, and to ensure that transactions are recorded—using recorded phone lines and instant messenger—and entered into NSPI's system.⁶²⁸ Power transaction confirmations are stored electronically at NSPI.⁶²⁹

All of NSPI's import (and export) transactions – including its short-term transactions (e.g., day-ahead and hour-ahead) – involve some form of human decision making and intervention and are not automatic,

⁶²⁴ "Mersey River Wind Inc. - 20250819 Power Purchase Agreement."

⁶²⁵ "Mersey River Wind Inc. - 20250819 Power Purchase Agreement."

⁶²⁶ Fuel Manual Revision 14, section 13.1.

⁶²⁷ Fuel Manual Revision 14, Appendix R.

⁶²⁸ Fuel Manual Revision 14, section 13.1.

⁶²⁹ Fuel Manual Revision 14, section 13.1.

that the figure does not include data from April 1, 2024 (hour ending 01:00) to April 25, 2025 (hour ending 02:00) due to the loss of that data in the cyber event.

Figure XII-9: Average Hourly Net Import over Nova Scotia-New Brunswick Intertie (MW)⁶³³



Because many transactions must rely on the New Brunswick-Nova Scotia intertie, and because that intertie has limited capability, NSPI was ultimately limited in the amount of power it could import during the Audit Period. Moreover, power imports also must be able to make their way from their source to the intertie, which requires transmission in New Brunswick. [REDACTED]

During the Audit Period, NSPI transacted with [REDACTED] counterparties: [REDACTED]. Figure XII-10 shows all import transactions during the Audit Period, as broken down by counterparty.

⁶³³ Data compiled from NSPI OASIS, available at <https://www.nspower.ca/oasis/monthly-reports/hourly-net-energy-flows-nb-nb-interconnection>. No data from April 1, 2025 (Hour-Ending 1:00) to April 25, 2025 (Hour-Ending 2:00) due to cyber event.

Figure XII-10: NSPI's Short-Term Power Imports, by Counterparty⁶³⁴

Counterparty	2024			2025		
	Number of Transactions	Transaction Volume	Average Price (USD/MWh)	Number of Transactions	Transaction Volume	Average Price (USD/MWh)

The figure above also shows transactions between NSPI and NSP Energy Marketing, Inc. (“NSPEMI”), which is a 100% subsidiary of NSPI. NSPEMI received approval from the Board to begin transacting for power and natural gas on November 29, 2018.⁶³⁵ Prior to the creation of NSPEMI, NSPI paid others—including Emera and New Brunswick Energy Marketing—to act as its agent for power and gas transactions in the U.S. The costs incurred by NSPEMI are passed through to NSPI, which then passes those costs to customers with no markup or additional costs. Other than the ability to transact in the U.S., NSPEMI’s creation changed little: the same NSPI employees that transacted in power and gas continued to do so, oversight of those transactions did not change, and no additional personnel were hired. The true “counterparty” in the case of all NSPEMI transactions above is the ISO New England power pool (which explains why, in 2025, no ISO New England transactions are listed). We formally address NSPEMI in our discussion of affiliate transactions later in this chapter.

We sampled several of NSPI’s import transactions during the Audit Period. Our goal was twofold. First, we wanted to determine if NSPI’s marketers were entering into import transactions that were expected to be beneficial to its customers. We say “expected” because the import with New England involves estimates of NSPI’s system marginal energy cost and ISO New England’s expected energy prices—ISO New England requires all import transactions to be secured approximately two hours ahead of energy flow. Second, given that the realized results may differ from the expected results at the time the transaction was executed, we wanted to know if, on net, NSPI’s imports are resulting in savings to customers. Importantly, the first step here involves looking at the prudence of the marketers: given the information known at the time of the transaction, was the transaction expected to produce savings for ratepayers? And in the second step, we are testing the efficacy of NSPI’s entire import approach. In that step, we not only consider whether marketers are prudent, but also whether NSPI’s process – which must include estimation and, in some cases, the risk of price movements in the two hours from transaction to energy flow – is working.

⁶³⁴ Quantities in the figure may not add up to aggregate data provided in NSPI’s quarterly FAM reports. This is largely due to transactions in which power does not flow (or is derated), resulting from actions system operators take to reduce or cut scheduled transactions because of insufficient transmission capability or for reliability reasons. Also, the data in the figure includes transmission losses, while data reported in the quarterly FAM reports does not.

⁶³⁵ NSUARB, “M08911 – Nova Scotia Power Inc. – NS Power Energy Marketing Inc. Pricing Protocol and Provision of Guarantees,” November 29, 2018.

NSPI enters into import transactions either for the economic benefit of FAM customers or for the reliability of the NSPI system. We address samples of both categories below.

XII.B.1.c.i.1. Economic Imports

We begin here with economic imports. Deciding to import power into Nova Scotia is not always based on a simple comparison of the cost of energy at the external source and [REDACTED]. There are several other costs involved (some known, some estimated) that must be considered. For imports that involve the New Brunswick transmission system, NSPI must pay (a) transmission reservation costs of CAD \$9.36/MWh for on-peak power or CAD \$4.45/MWh for off-peak power and (b) estimated transmission losses of about 3.3%. For ISO New England transactions, until December 2025, NSPI was required to pay USD \$27.67/MWh per transaction for the ISO New England Tariff fee, after which the fee was reduced to USD \$23.39/MWh. Thanks to NSPEMI's ability to transact with all relevant counterparties, NSPI no longer pays marketing or agent fees for its power transactions, which were as much as USD [REDACTED]/MWh in prior audit periods. Therefore, for an import to be economic, it must be so including all these various charges—in addition to the cost of the import itself.

All these costs are known. They are added on top of the actual price for the import, which can be sourced from another Canadian province or from New England. If the import is sourced from another province, its cost is known at the time of the transaction; if the import is from New England, the price must be estimated two hours in advance.

In reviewing a sample of NSPI's economic imports, we found that NSPI's marketers continue to use tools that allow them to compare the full cost of [REDACTED]. This allows NSPI to use the best possible information in determining whether a potential import transaction is economic. For our sample of economic import transactions, we found that (a) NSPI's traders acted prudently in every case, executing transactions that were projected to provide net benefits to FAM customers, and (b) those transactions resulted in economic benefits for ratepayers, with just one exception, explained below. As part of our transaction review, we reviewed a subset of emails pertaining to energy desk transactions. The one exception occurred on December 9, 2025, when NSPI purchased an 18-hour strip of day-ahead power from ISO New England. At the time of execution, the transaction was expected to generate savings of \$ [REDACTED] for FAM customers. However, actual New England prices increased following execution, leading to a loss of \$ [REDACTED]. We take no issue with this transaction, however, as it was forecasted to provide benefits for customers.

XII.B.1.c.i.2. Reliability Imports

In our review of import transaction samples, we noted [REDACTED] days during the Audit Period when NSPI imported energy for system reliability purposes. As NSPI has explained to us in the past, all reliability import transactions are made at the request of the NSPSO, which is ultimately responsible for the reliable

operation of the system in Nova Scotia.⁶³⁶ The total volume of reliability transactions was 5,185 MWh, with an average price of \$[REDACTED]/MWh, which is considerably [REDACTED] than the average price of imports made for economic reasons. This is unsurprising, as reliability imports are typically pursued when system conditions are tight and prices in both Nova Scotia and neighboring control areas are elevated. The reliability imports during the Audit Period were sourced in New Brunswick, ISO New England, or Newfoundland and Labrador.

The highest priced reliability import was reported in Allegro at \$[REDACTED]/MWh, which was the second hour of a four-hour real-time import from ISO New England. We reviewed this transaction's circumstances and found NSPI acted reasonably. System conditions throughout the day were tight and at 16:24, the System Operator requested NSPI's marketers procure 75 MW of imported power for hour ending 19:00 through 21:00. NSPI's marketers informed the System Operator that prices in New England were high and expected to rise, but the System Operator maintained the request given reliability conditions on the system. Despite the high prices in New England, the transaction actually saved USD \$[REDACTED] given the ultimate real-time prices in New England and the system cost in Nova Scotia.

XII.B.1.d. Transactions over the Maritime Link

This section addresses all power imported from Newfoundland and Labrador. Throughout this report, we may refer to this power as "Muskrat Falls" energy or generation, which refers to the 824 MW hydroelectric generating station on the Churchill River in Labrador owned by Newfoundland and Labrador Hydro, or NLH.⁶³⁷ We may also refer to the power as "Maritime Link" energy, which is the 500 MW high-voltage direct current ("HVDC"), subsea transmission line owned by an NSPI affiliate (NSP Maritime Link Inc., or "NSPML") that connects Nova Scotia to Newfoundland and Labrador and is the final transmission leg of energy generated at Muskrat Falls. We also reference the "Labrador Island Link," which is an 1,100 km HVDC transmission line that transports power from Muskrat to the Maritime Link. When we refer to these terms, we are addressing the overall package of energy, capacity, and transactional activity associated with NSPI and NLH. However, the specific products (e.g., NS Block, Supplemental Energy, etc.) are more nuanced and require explanation. We begin with a refresher on the contracts through which NSPI purchases energy and capacity from NLH.

XII.B.1.d.i. Background on Transactions over the Maritime Link

The Maritime Link was placed into service on January 15, 2018.⁶³⁸ However, as a consequence of delays in the construction and commissioning of both the Muskrat Falls Generating Station and the

⁶³⁶ *Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules*, Chapter 3: Reliability Planning Requirements, Effective December 20, 2012, section 3.1.1.1, available at <http://oasis.nspower.ca/site/media/oasis/Appendix%2025%20-%20Market%20Rules%20Ch%203.pdf>.

⁶³⁷ See Newfoundland and Labrador Hydro, "Our Generation Assets," available at: <https://nlhydro.com/about-us/our-electricity-system/our-generation-assets/>.

⁶³⁸ NSUARB, "Decision," M10206, paragraph 9.

Labrador Island Link, delivery of the products promised to NSPI under the contractual arrangements between NSPI, NLH, and NSPML were delayed.⁶³⁹ We explain those contractual arrangements here.

There are three key commercial agreements that govern the provision of energy and capacity by NLH to NSPI. The first is the “Energy and Capacity Agreement,” or “ECA.”⁶⁴⁰ Executed on July 31, 2014, the ECA required NLH to provide NSPI with the “Nova Scotia Block,” or “NS Block,” which included (1) a “Base Block” of energy, which is on-peak energy⁶⁴¹ to be delivered every day for the entirety of the 35-year initial term of the contract, and (2) a “Supplemental Block” of energy, which is off-peak energy⁶⁴² to be delivered for the winter months⁶⁴³ only in the first five years of the initial term of the contract. Specifically, the ECA calls for the delivery of 0.986 TWh/year of Base Block⁶⁴⁴ for the 35-year contract term, and approximately 0.240 TWh/year of Supplemental Block for the first five years of the contract.⁶⁴⁵

The second key contractual document is the Energy Access Agreement,⁶⁴⁶ or “EAA,” which governs the provision of “Surplus Energy,” which may also be referred to as “NLH Market-Priced Energy.” Surplus Energy is energy above and beyond the NS Block quantities for sale to NSPI, priced based on a formula that is capped at current market prices.⁶⁴⁷ The Energy Access Agreement guarantees NSPI the right of first refusal to quantities of energy beyond the NS Block and was a key component of the Board’s approval of the Maritime Link project in 2013.⁶⁴⁸ Under the bargain approved by the Board in 2013, NSPI was to receive (1) 895 GWh of Base Block Energy each year for 35 years and (2) 240 GWh of Supplemental Energy in the winter months of the first five years after commercial operations commencement, plus access to additional estimated quantities of Surplus Energy.⁶⁴⁹ Over the term of the EAA, NLH is required to make available at least 1.2 TWh (with annual delivery that could vary substantially by year and as low as zero in a given year⁶⁵⁰), over the term of the agreement,⁶⁵¹ which expires no earlier than August 31, 2041.⁶⁵²

⁶³⁹ NSUARB, “Decision,” M10206, paragraph 9.

⁶⁴⁰ Amended and Restated Energy and Capacity Agreement between Nalcor Energy and Emera Inc., July 31, 2014 (“ECA”), provided as Nalcor – Amended-and-restated-energy-and-capacity-agreement (1).pdf.

⁶⁴¹ On-peak energy is energy that is delivered over the 16-hour peak period of each day, seven days per week.

⁶⁴² Off-peak energy is energy that is delivered over the 8-hour off-peak period of each day, seven days per week.

⁶⁴³ The winter months are November through March, inclusive.

⁶⁴⁴ ECA, PDF page 19.

⁶⁴⁵ 2022-2023 Bates White Audit Report, page 331.

⁶⁴⁶ Nalcor-NSPML-Energy-Access-Agreement-April-2015-for-web.pdf (“EAA”).

⁶⁴⁷ Prices for Surplus Energy are capped at the higher of [REDACTED] and (b) [REDACTED] as long as NLH can demonstrate that the [REDACTED] and that [REDACTED] can access an [REDACTED] among other required demonstrations. EAA, section 2.4.

⁶⁴⁸ NSUARB, “Decision,” M10206, February 9, 2022, paragraphs 51 to 52.

⁶⁴⁹ NSUARB, “Decision,” M05419, July 22, 2013, paragraphs 30 to 36.

⁶⁵⁰ NSUARB, “Supplemental Decision,” M05419, November 29, 2013, paragraph 13.

⁶⁵¹ EAA, section 4.1(a).

⁶⁵² EAA, section 9.2(a).

The third key contractual document is the “Acceleration Agreement.”⁶⁵³ On August 6, 2021, Emera, NLH, NSPI, and NSPML agreed to execute an agreement that would redefine the commercial operations date of the NS Block. Rather than conforming to the original definition of NS Block commencement—which required both the Muskrat Falls Generating Station and Labrador Island Link (and associated transmission assets) to be fully operational—this so-called “Acceleration Agreement” declared August 15, 2021 to be the commencement date of the NS Block.⁶⁵⁴ This was a particularly material change since the Labrador Island Link remained the reason for the delay of the NS Block, as commissioning and testing activities remained ongoing. The Acceleration Agreement also would excuse any underperformance of NLH in supplying the full quantities of the NS Block if that underperformance were caused by testing and commissioning activities on the Labrador Island Link.⁶⁵⁵ The Acceleration Agreement further stated that the first contract year of the EAA would begin on September 1, 2022.⁶⁵⁶

In the 2020-2021 audit period, portions of the NS Block began to flow starting August 15, 2021.⁶⁵⁷ On August 18, 2021, NSPML filed an application to the Board for full cost recovery for the Maritime Link,⁶⁵⁸ an application that could not occur until the NS Block had commenced. That application’s proceeding before the Board considered the Acceleration Agreement’s impact and prudence, with the Board ultimately concluding that it was reasonable and appropriate for NSPML to negotiate and enter into the Acceleration Agreement.⁶⁵⁹ The Board also identified the FAM Audit process as the appropriate forum to review the economic value received by ratepayers from transactions involving the re-delivery of the NS Block and other associated products from NLH.⁶⁶⁰ Our prior audit reports reviewed the NS Block deliveries received, compared them to the ECA contract requirements, and addressed NSPI’s approach to tracking, valuing, and recouping the value of undelivered NS Block volumes.⁶⁶¹

Below, we review and assess Audit Period results for two distinct products. First, we review and assess deliveries of NS Block energy. This includes discussion of undelivered NS Block volumes, make-up deliveries, and the valuation of each. Second, we review and assess Surplus Energy volumes pursuant to the EAA. This includes a review of NLH’s obligation to provide NSPI a right of first refusal on Surplus Energy, as well as NSPI’s decisions to receive that energy, and an accounting of the energy that flowed.

⁶⁵³ Nalcor – Letter Acceleration Agreement re NS Block – (fully executed), 06-08-21.pdf (“Acceleration Agreement”).

⁶⁵⁴ Acceleration Agreement, section 1.

⁶⁵⁵ Acceleration Agreement, section 3.

⁶⁵⁶ Acceleration Agreement, section 4.

⁶⁵⁷ 2020-2021 Bates White Audit Report, page 307.

⁶⁵⁸ See Matter M10206.

⁶⁵⁹ NSUARB, “Decision,” M10206, February 9, 2022, paragraph 56.

⁶⁶⁰ NSUARB, “Decision,” M10206, February 9, 2022, paragraph 68.

⁶⁶¹ 2022-2023 Bates White Audit Report, pages 333 to 355.

XII.B.1.d.ii. NS Block Deliveries (Pursuant to ECA)

Tracking of Undelivered, Makeup NS Block Volumes

Entering the Audit Period, NSPI was owed a balance of 201,779 MWh of undelivered Base Block energy.⁶⁶² On June 22, 2024, the undelivered Base Block volume net of makeup energy received reached zero for the first time.⁶⁶³ This milestone closed the chapter on a multi-year period during which NLH carried a substantial deficit of Base Block volumes to deliver.

During the Audit Period, NSPI received 1,666,975 MWh of Base Block, which was approximately 85 percent of the contract volume of 1,972,075 MWh. NSPI also received 506,086 MWh of make-up Base Block energy. Factoring in the 201,779 MWh of undelivered Base Block energy as of the beginning of the Audit Period, the total of undelivered Base Block volumes at the end of the Audit Period was 793 MWh. This is a small and manageable quantity, and going forward, the ongoing balance of over/under-delivered energy is expected to be non-zero given the nature of the volumes contracted and actually delivered. An accounting of NSPI's monthly Base Block deliveries during the Audit Period is shown in Figure XII-11 below.

⁶⁶² 2022-2023 Bates White Audit Report, page 334.

⁶⁶³ 2024 Maritime Link Benefits Report, Q2 2024, August 13, 2024, section 2.1.

Figure XII-11: Base Block Volumes (MWh)

Month	Contract Volume (MWh)	Hourly Deliveries up to Contract (MWh)	Make-Up Energy (MWh)	Total Base Block Deliveries (MWh)	Net Over/(Under) Deliveries (MWh)	Cumulative Undelivered Base Block Volume (MWh)
Jan-24	83,526	83,514	15,027	98,541	15,015	186,764
Feb-24	78,138	76,442	45,017	121,459	43,322	143,443
Mar-24	83,526	70,880	52,058	122,938	39,412	104,031
Apr-24	80,832	48,301	36,318	84,618	3,786	100,245
May-24	83,526	51,612	58,412	110,024	26,498	73,747
Jun-24	80,832	80,161	73,036	153,197	72,365	1,382
Jul-24	83,514	72,038	1,194	73,232	(10,282)	11,664
Aug-24	83,514	0	0	0	(83,514)	95,177
Sep-24	80,820	35,923	12,992	48,914	(31,906)	127,083
Oct-24	83,514	69,196	3,889	73,085	(10,429)	137,511
Nov-24	80,820	78,361	56,355	134,716	53,896	83,615
Dec-24	83,514	82,782	83,770	166,552	83,038	577
Jan-25	83,742	71,121	9,026	80,147	(3,595)	4,172
Feb-25	75,638	75,638	4,710	80,348	4,710	(537)
Mar-25	83,742	83,420	572	83,992	250	(787)
Apr-25	81,041	62,414	12,249	74,663	(6,378)	5,591
May-25	83,742	83,154	5,310	88,464	4,722	870
Jun-25	81,041	79,912	1,036	80,948	(93)	963
Jul-25	83,742	80,008	3,575	83,583	(159)	1,122
Aug-25	83,742	83,679	421	84,100	358	765
Sep-25	81,041	52,751	10	52,761	(28,280)	29,045
Oct-25	83,742	80,901	8,493	89,394	5,652	23,393
Nov-25	81,041	81,025	10,036	91,061	10,020	13,373
Dec-25	83,742	83,742	12,581	96,323	12,581	793
Total	1,972,075	1,666,975	506,086	2,173,061	200,986	793

Turning to Supplemental Block energy, NSPI was owed 54,833 MWh of undelivered Supplemental Block at the end of the prior audit period.⁶⁶⁴ On November 21, 2024, the undelivered Supplemental Block volume net of makeup energy received also reached zero for the first time.⁶⁶⁵

During the Audit Period, NSPI received 519,728 MWh of Supplemental Block, which was approximately 97 percent of the contract volume of 533,453 MWh. NSPI also received 75,355 MWh of make-up Supplemental Block energy. Factoring in the 54,833 MWh of undelivered Supplemental Block energy as of the beginning of the Audit Period, NSPI enjoyed a surplus of 6,797 MWh of Supplemental Block energy at the end of the Audit Period. An accounting of NSPI's monthly Supplemental Block deliveries during the Audit Period is shown in Figure XII-12 below.

⁶⁶⁴ 2022-2023 Bates White Audit Report, page 334.

⁶⁶⁵ 2024 Maritime Link Benefits Report, Q4 2024, March 10, 2025, section 2.1.

Figure XII-12: Supplemental Block Volumes (MWh)

Month	Contract Volume (MWh)	Hourly Deliveries up to Contract (MWh)	Make-Up Energy (MWh)	Total Supplemental Block Deliveries (MWh)	Net Over/(Under) Deliveries (MWh)	Cumulative Undelivered Supplemental Block Volume (MWh)
Jan-24	54,634	54,086	14,439	68,525	13,891	40,942
Feb-24	51,098	50,252	21,420	71,672	20,574	20,368
Mar-24	54,376	49,659	24,822	74,481	20,105	263
Apr-24	0	0	0	0	0	263
May-24	0	0	0	0	0	263
Jun-24	0	0	0	0	0	263
Jul-24	0	0	0	0	0	263
Aug-24	0	0	0	0	0	263
Sep-24	0	0	0	0	0	263
Oct-24	0	0	0	0	0	263
Nov-24	52,753	52,224	8,363	60,587	7,834	(7,571)
Dec-24	54,262	53,507	803	54,310	48	(7,618)
Jan-25	54,664	50,437	3,527	53,964	(700)	(6,918)
Feb-25	49,426	48,389	399	48,788	(638)	(6,281)
Mar-25	54,513	53,590	1,241	54,831	318	(6,599)
Apr-25	0	0	0	0	0	(6,599)
May-25	0	0	0	0	0	(6,599)
Jun-25	0	0	0	0	0	(6,599)
Jul-25	0	0	0	0	0	(6,599)
Aug-25	0	0	0	0	0	(6,599)
Sep-25	0	0	0	0	0	(6,599)
Oct-25	0	0	0	0	0	(6,599)
Nov-25	53,092	53,024	341	53,365	273	(6,872)
Dec-25	54,634	54,560	0	54,560	(74)	(6,797)
Total	533,453	519,728	75,355	595,083	61,630	(6,797)

We reviewed NSPI's accounting for the NS Block volumes and had no concerns. NSPI maintains an hourly tracker of NS Block quantities delivered and reconciles it against NLH's contractual obligations to derive the hourly under-deliveries.

What is clear from the figures above is that deliveries of both Base and Supplemental Block improved during the Audit Period, which, combined with makeup volumes, allowed NLH to eliminate the long-standing deficits of both Base and Supplemental Block by June 2024 and November 2024, respectively. Since those dates, undelivered volumes have been minimal, with NSPI suffering material underdeliveries in three months (August 2024, September 2024, and September 2025), which occurred largely due to planned maintenance activities on the LIL; NSPI explained these maintenance activities were scheduled for periods of lower system load and lower replacement energy costs. In all cases, makeup volumes were received relatively promptly. For example, the undelivered August and September 2024 volumes were largely redelivered in November and December 2024, while the September 2025 undelivered volumes were delivered in the October–December 2025 timeframe.

Under the ECA, when NLH fails to deliver NS Block quantities equal to its contractual obligations (whether Base or Supplemental), two separate remedies apply depending upon the circumstances. If the undelivered quantities are due to a "Forgivable Event," such as force majeure, NLH is obligated to deliver all undelivered quantities during the term of the ECA. This is so-called "Block A Undelivered Energy." For all Block A Undelivered Energy, NLH must, within a short period of time, work with NSPI to

schedule delivery of makeup energy—this is so-called “Base Energy.”⁶⁶⁶ That makeup Base Energy is subject to a “Similar Value” provision, which states:

Similar Value – The Base Energy will be delivered during the corresponding periods of Peak Hours and Off-Peak Hours which had been scheduled for the original deliveries of such Energy.⁶⁶⁷

Undelivered energy that is not excused by a Forgivable Event is considered “Block B Undelivered Energy” and must be replaced by “Compensation Energy,” which requires NLH to pay damages either in the form of delivery of additional energy beyond the shortfall, monetary compensation, or GHG credits.⁶⁶⁸

[REDACTED]

[REDACTED] Under the ECA, the parties are required to negotiate a solution,⁶⁶⁹ and barring that, proceed to mediation.⁶⁷⁰ If that fails, the parties either agree to an arbitration procedure or litigation.⁶⁷¹ In our view, NSPI has reasonably pursued this issue and we include a recommendation that NSPI update the Board on the resolution of this issue.

Valuation of Undelivered, Makeup NS Block Volumes

In our prior audit report, we explained NSPI’s efforts to ensure that makeup volumes of NS Block energy meets the terms of the ECA. We also explained NSPI’s mechanism for tracking the value of the undelivered volumes and makeup volumes to understand the net impact on FAM customers. These two concepts are different. The ECA defines “similar value” in terms of the timing of the redeliveries, requiring that the makeup energy be “delivered during the corresponding periods of Peak Hours and Off-Peak Hours which had been scheduled for the original deliveries of such Energy.”⁶⁷² There is no monetary value associated with this contractual provision. Still, in our view it is critical to understand the net impact on FAM customers. Our prior audit report noted that NSPI had met the requirements of the ECA on all redeliveries, excepting 82,341 MWh, and that its valuation methodologies used to date lead to different

⁶⁶⁶ See ECA, Schedule 5, section 5.

⁶⁶⁷ ECA, Schedule 5, Section 5(b)(iii)(D).

⁶⁶⁸ ECA, Article 8.4. See also, ECA, Schedule 5, Section 5.

⁶⁶⁹ ECA, Schedule 6, section 2.1 (a).

⁶⁷⁰ ECA, Schedule 6, section 2.1 (b)(i).

⁶⁷¹ ECA, Schedule 6, section 2.1 (b)(ii).

⁶⁷² ECA, Schedule 5.

results on assessing the net impact on FAM customers.⁶⁷³ We included recommendations that NSPI maintain its pursuit of all undelivered volumes and attempts to accurately value the missing and makeup volumes.⁶⁷⁴

Our prior audit report was issued July 5, 2024, just days after the deficit of Base Block volumes reached zero. The hearing for the prior FAM audit took place in March 2025, by which point the Supplemental Block deficit had also been erased. In the runup to hearing, and beginning in January 2025, Bates White had several exchanges with NSPI regarding its NS Block valuation model and analysis, including several calls and email exchanges. We submitted numerous written questions to NSPI and discussed many others in teleconferences. In each case, NSPI provided Bates White with responsive answers and additional information and data.⁶⁷⁵

On March 14, 2025, we filed a memo in M11533 explaining the status of the valuation review. We explained that NSPI had used multiple methods for tracking the value of undelivered and makeup NS Block volumes, and the methods produce materially different results.⁶⁷⁶ They included:

The “Hourly Replacement Method” calculates on an hourly basis the cost of the MWh of energy needed to make up for any undelivered NS Block quantities, or the cost of the displaced energy for any quantities of makeup NS Block deliveries. The fuel and purchased power costs used to calculate the replacement/displaced energy volumes are forward replacement costs. Term gas prices are based on the index associated with the base procured gas, while incremental gas is priced at spot. Imported power is priced based on spot prices or term prices (pursuant to term RFPs), if applicable. Solid fuel is priced at the prompt quarterly forward price. This method does not involve a PortOps run, but rather is an Excel-based exercise that uses marginal cost data.

The “Monthly Accounting Method” varied in two important ways from the Hourly Replacement Method. First, this approach did not consider hourly cost impacts. Instead, this method valued all system volumes at a single average monthly price. As noted above, NSPI pursued this approach as more accurate during periods of high fuel price volatility, with the method aiming to determine the costs charged to FAM customers, i.e., the method NSPI already uses for tracking overall monthly FAM costs for customers. Second, instead of using marginal costs (based on forward replacement prices), this approach uses an accounting-based approach that captures the weighted-average cost of consumed fuel inventories consumed for system production.⁶⁷⁷

We explained that we were critical of the Monthly Accounting Method,⁶⁷⁸ while NSPI was critical of the Hourly Replacement Method.⁶⁷⁹ We acknowledged a flaw with the Hourly Replacement Method (as it

⁶⁷³ 2022-2023 Bates White Audit Report, Conclusions XII-17, XII-18.

⁶⁷⁴ 2022-2023 Bates White Audit Report, Recommendations XII-2, XII-3.

⁶⁷⁵ Exhibit N-34, M11533.

⁶⁷⁶ Exhibit N-34, M11533, page 2.

⁶⁷⁷ Exhibit N-34, M11533, page 2.

⁶⁷⁸ 2022-2023 Bates White Audit Report, page 344.

⁶⁷⁹ 2022-2023 Bates White Audit Report, page 344.

related to coal prices)⁶⁸⁰ and recommended NSPI “not abandon” the Hourly Replacement Method but should adjust it as needed.⁶⁸¹

We explained that since January 2025, NSPI made changes to its approach for valuing both the undelivered and makeup volumes of energy. We highlighted the key changes:

First, NSPI has adjusted the “Accounting” method to account for the sources of generation in a given hour in which undelivered volumes accrued. In the “Monthly Accounting Method” explained above, NSPI would calculate a single, system-wide monthly price that would apply to all generation in all hours, regardless of the actual mix of generation providing power. Now, NSPI has enhanced the granularity of its analysis by determining the fuel mix in each hour and calculating the value of the undelivered volumes accordingly. This is a substantial improvement and appears responsive to our related concerns raised in our Audit Report. We refer to this as the “Adjusted Accounting Method.”

Second, NSPI has introduced a method for pricing coal-fired generation in the valuation calculation. This approach values coal based on incremental coal purchases driven by undelivered energy. Or, for makeup energy, this method attempts to calculate the value of coal cargoes that NSPI did not have to purchase due to the delivery of makeup energy.

Third, NSPI is not using the same method for valuing the undelivered volumes as it is for the makeup volumes. Specifically:

For undelivered volumes, NSPI is using the “Adjusted Accounting Method” (which includes an adjustment for additional granularity, as explained above), and using the “incremental cargo” approach for determining hourly coal prices.

For makeup volumes, NSPI is using the “Replacement Method,” also using hourly prices, and using the “incremental cargo” approach for any coal generation starting January 1, 2023.⁶⁸²

We then provided our assessment of the status of NSPI’s valuation work at that point. We noted that “NSPI’s work in determining the final values of the undelivered and makeup volumes of NS Block energy is not yet complete” since despite the significant work to date, our discussions with NSPI on the topic had not yet been completed.⁶⁸³ We acknowledged that NSPI had made “improvements to its approach,” including “additional granularity to its Accounting Method” and its use of the “incremental cargo” approach “that attempts to better capture the incremental cost of coal.”⁶⁸⁴ We noted that NSPI has “reasonably grappled with the complexity and subjectivity in the valuation of undelivered and makeup volumes of NS Block energy,” and that the Board and stakeholders should be aware “that the choice of method for valuing the undelivered and makeup volumes is material and can lead to significantly different

⁶⁸⁰ 2022-2023 Bates White Audit Report, page 344.

⁶⁸¹ 2022-2023 Bates White Audit Report, Recommendation XII-3.

⁶⁸² Exhibit N-34, M11533, pages 3 to 4.

⁶⁸³ Exhibit N-34, M11533, page 4.

⁶⁸⁴ Exhibit N-34, M11533, page 4.

conclusions about the relative value of the makeup volumes relative to the undelivered volumes.”⁶⁸⁵ We stated that “in order to complete our work, we would wish to conduct final due diligence on NSPI’s data and model to ensure accurate data and calculations,” noting that we would appreciate the opportunity to work with NSPI to finalize this work and acknowledged NSPI’s willingness to do the same.⁶⁸⁶ In its Decision in that matter, the Board directed this issue be reviewed in the next FAM Audit.⁶⁸⁷

Following the hearing, we met with NSPI on nine separate occasions to review and assess the valuation modeling. We worked to find areas of agreement and to fully understand and pinpoint areas of disagreement. NSPI remained responsive to our questions and requests. By June 2025, we completed this work. We agreed with NSPI’s approach for valuing makeup energy received. We did not fully agree with NSPI’s approach for valuing undelivered energy, though through the work accomplished in March-June of 2025, we substantially reduced areas of disagreement. On June 27, 2025, NSPI presented the results of this work to the FAM Small Working Group, which we attended, provided comments, and were available for questions. NSPI also provided a summary memo and summary slides in support of this meeting.

NSPI’s June 25, 2025 memo, which we reviewed and provided comments on prior to distribution to the SWG, reasonably summarized the results of the valuation analysis. Regarding the valuation of makeup energy:

Bates White and NS Power agree on the estimated value of make up energy. The valuation of the make up energy involves modelling that determines replacement costs for incremental fuel that would have been required had the make up energy not been received. Also, the available generation that could have replaced those make up megawatts are bound by what was available on that day; the physical limits of the system were taken into consideration to accurately reflect what would have replaced make up energy had it not been delivered. The total estimated value of make up energy is [REDACTED] million.⁶⁸⁸

Regarding the valuation of undelivered energy, the memo reasonably noted:

NS Power’s method for valuing undelivered energy is based on the true cost of replacement which can be determined based on known costs that actually occurred. The analysis utilizes incremental accounting costs, including the actual costs of incremental coal cargoes that were purchased, to accurately reflect the true cost of replacing the amount of NS Block energy that was not delivered. To determine the sources of energy that replaced the NS Block energy that should have been delivered, NS Power ranked from highest to lowest, the actual cost of dispatched generation.

Bates White partially agrees with NS Power’s approach to valuing undelivered energy. Bates White agrees with NS Power’s approach to valuing coal-fired generation, which utilizes the cost of incremental coal cargoes that were purchased. However, Bates White believes that it is more appropriate to use the real-time replacement pricing of energy for other non-coal generation to

⁶⁸⁵ Exhibit N-34, M11533, page 4.

⁶⁸⁶ Exhibit N-34, M11533, page 6.

⁶⁸⁷ NSEB, “Decision,” M11533, October 16, 2025, paragraph 235.

⁶⁸⁸ NSPI, June 25, 2025 Memo to FAM Small Working Group, NSEB, page 5.

reflect the cost of replacing undelivered NS Block energy. Quantified further in Section 6.0, NS Power disagrees with the use of forward replacement pricing for the undelivered energy which varies from the actual cost of replacement energy. This is particularly true in 2022, because of increased volatility in forward pricing due to the onset of the Russian invasion of Ukraine.⁶⁸⁹

Under NSPI's approach, the valuation of the undelivered volumes equals \$ [REDACTED] million, while under our approach, the value of the undelivered volumes equal \$ [REDACTED] million.⁶⁹⁰ These different approaches lead to different net impacts on FAM customers. NSPI's approach shows a net benefit of \$ [REDACTED] million, while our method shows a net cost of \$ [REDACTED] million. This is shown in the table below.

Figure XII-13: NS Block Undelivered, Makeup Volume Valuation Results⁶⁹¹

Estimated Values (\$M)	NSPI Method	Bates White Method
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]

In addition to these core calculations, we also considered the impact of SO₂ emissions compliance costs. NSPI's memo reasonably explained:

NS Power and Bates White agree that there is additional value of make up energy beyond that calculated in the model, related to SO₂ compliance. While the avoided cost of SO₂ compliance achieved by make up energy is captured through the Emission Compliance Adders, there is additional value to customers from the make up energy received in the 2023/2024 period. NS Power attempted to quantitatively capture the impact that the SO₂ emissions requirement would have caused, had the make up energy not been received. Due to the complexity of this quantification, and in conjunction with discussions with Bates White, the value was not included in the analysis but is described here. NS Power reasonably believes the value to customers is in [REDACTED]. This range reflects the degree of compliance required and its impact on the system. If NS Power can achieve compliance without severely limiting the performance of the coal generation fleet - by using a significant amount of low-sulphur fuel that reduces output - then less reliance on combustion turbines (CTs) or other expensive alternative generation would be necessary. In this scenario, the cost impact would align with the [REDACTED]. However, if, as experienced during the summer of 2024, coal generation is significantly constrained and lower-cost alternatives are unavailable, the [REDACTED] would apply.

In 2023 and 2024 the regulated allowable limit on SO₂ emissions decreased materially from the allowances in 2021 and 2022. This placed a limit on the amount of generation which could be generated from solid fuel power plants. NS Power utilized low sulphur coal blends to ensure

⁶⁸⁹ NSPI, June 25, 2025 Memo to FAM Small Working Group, NSEB, page 4.

⁶⁹⁰ NSPI, June 25, 2025 Memo to FAM Small Working Group, NSEB, page 5.

⁶⁹¹ NSPI, June 25, 2025 Memo to FAM Small Working Group, NSEB, page 6.

compliance, and generation from Tufts Cove was the highest it had been since 2011 when NS Power had access to Sable offshore gas.

In addition, imports over the NS/NB tie reached a record high during the 2021 through 2024 period and would have reached a similar level in 2024 had NB Power not experienced an extended outage at the Point Lepreau Nuclear Generation Station.

Even with this increased lower-emitting energy including the make up energy volumes, SO₂ emissions were very close to the allowable limit of 68 kt, reaching 66.9 kt for the 2023/24 compliance period. Therefore, the make up energy was of particular value over the 2023/24 period, when SO₂ limits became stricter. Had NS Power received all the NS Block energy in 2021 and 2022, it would have had to acquire a significant portion of non-emitting energy along with the usage of Emission Compliance Adders to ensure compliance over the 2023/24 period.⁶⁹²

NSPI received makeup energy at later periods than the undelivered volumes, and because sulfur emissions compliance targets became more strict with time, we agreed that directionally, there is a net benefit associated with the makeup volumes relative to the undelivered volumes. We did not agree with the scale of the benefit range calculated by NSPI [REDACTED] and agreed with NSPI's decision to leave this estimate out of the core valuation. Still, we do agree that in terms of sulfur compliance, the makeup volumes provided an additional net benefit for FAM customers that were not fully captured in the dispatch cost adders used by NSPI.

As a final point, we also reviewed the value of the makeup volumes associated with the 82,341 MWh of makeup volumes that we had previously noted were delivered contrary to the "Similar Value" terms of the ECA. Specifically, we noted that

Specifically, NSPI received 82,341 MWh of makeup Supplemental Block energy in non-winter months (April, May, June 2022)... Thus, from a strict reading of the "similar value" provision, NSPI appears to have received "similar value" for all but 82,341 MWh of off-peak energy. NSPI explained that it received these volumes during periods of high energy prices in the wake of the start of the conflict in Ukraine. We include a recommendation that NSPI address this issue.⁶⁹³

As a preliminary matter, we note that this 82,341 MWh of undelivered energy is not in dispute between NSPI and NLH and has long since been redelivered. Moreover, it is not our intent to require NSPI to pursue a contractual remedy that will result in additional costs to FAM customers. Given that, we reviewed NSPI's analysis related to its decision to receive makeup volumes of Supplemental Block during periods non-winter months. NSPI's analysis is based on the avoided cost of replacement coal, taking the simple average of the API-2 coal forwards for the periods where the volumes were redelivered (April-June 2022) compared to the simple average of the first potential eligible (winter) months for redelivery that would comply with the terms of the ECA (November-December 2022). The result shows a net benefit for FAM customers of approximately \$ [REDACTED] million, which is due to the higher forward prices

⁶⁹² NSPI, June 25, 2025 Memo to FAM Small Working Group, NSEB, page 7.

⁶⁹³ 2022-2023 Bates White Audit Report, section XII.B.1.d.

for the April-June 2022 period relative to the November-December 2022 period. This analysis helps demonstrate the reasonableness of NSPI's decision at the time, and while we have no insight into why NLH agreed to this approach, we suspect NLH was interested in reducing the cumulative deficits of Base and Supplemental Block that had been accruing since August 2021.

Finally, we note that as of the end of March 2026, NSPI will no longer receive Supplemental Block volumes due to the natural expiration of the five-year delivery term of that product under the ECA. Recall that under the ECA, NSPI receives 240 GWh/year of Supplemental Block energy, to be delivered in the off-peak hours of the winter months, for the first five years of the ECA term. This is zero-priced energy, meaning the end of the Supplemental Block deliveries will mean higher FAM costs for customers, as that energy is replaced with other, non-zero priced alternatives. NSPI has not conducted rigorous estimate of this potential cost increase, but roughly estimated the impact to be in the range of [REDACTED] million/year, assuming 240 GWh of energy transacted at prices between [REDACTED]/MWh and [REDACTED]/MWh. In our view, this is a reasonable rough estimate. The one upside to the expiration of the Supplemental Block volumes is that NSPI may benefit from increased availability of EAA Surplus Energy in the off-peak hours of winter months, since NLH will have more available capability with which to transact. However, the Surplus Energy is priced at the Mass Hub day-ahead price and will impose incremental costs on FAM customers.

XII.B.1.d.iii. Surplus Energy Deliveries (Pursuant to EAA)

Under the terms of the EAA, NSPI may (at its sole option) issue a competitive market solicitation ("EAA RFP") by June 15 for energy to be delivered in the next contract year.⁶⁹⁴ NLH is then required "to respond in good faith to such [EAA RFP]" as long as it forecasts positive "Available Energy" for the contract year.⁶⁹⁵ Available Energy is energy that is excess to NLH's native load and NS Block obligations (excluding any make-up NS Block deliveries).⁶⁹⁶ NLH is required to provide a forecast to NSPI of its available energy for the upcoming contract year by March.⁶⁹⁷ We received all 24-month and rolling four-week ahead forecasts of EAA energy for the Audit Period. In this section, we provide results from the two EAA RFPs.

XII.B.1.d.iii.1. 2024 EAA RFP

NSPI issued its first of two EAA RFPs of the Audit Period on April 24, 2024, with responses due by May 24, 2024. NSPI sought offers for up to 150 MW of firm energy (with greater or lesser volumes being considered) in the form of standard products (5x16, 7x16, and 7x24 around-the-clock), though any non-standard products received were also considered. The EAA RFP sought energy for the period September 1, 2024 through September 1, 2025. The RFP was sent to four recipients: [REDACTED]
[REDACTED]. NSPI received offers from [REDACTED] counterparties [REDACTED] submitted

⁶⁹⁴ EAA, section 2.2.

⁶⁹⁵ EAA, section 2.3.

⁶⁹⁶ EAA, section 1.1.

⁶⁹⁷ EAA, section 2.1(b).

a single offer with offerings in each of the twelve months, while [REDACTED] offered two separate offers each covering nine months of the period, with one set of offers being a peak product (5x16) and the other set a round-the-clock offer (7x24). [REDACTED] offers were firm, though contingent on [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]

NSPI used PLEXOS to evaluate the bids. [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Figure XII-14 below provides a summary of the first EAA RFP held during the Audit Period. [REDACTED] offers are shown first, with indications that all offers were selected. Next is [REDACTED] offers, with winning offers being indicated as such. The bottom rows of the figure provide the combined results across all offers and winning offers.

[illegible]

NSPI issued its second of two EAA RFPs of the Audit Period on June 11, 2025, with responses due by July 11, 2025. NSPI sought offers for up to 150 MW of firm energy (with greater or lesser volumes being considered) in the form of standard products (5x16, 7x16, and 7x24 around-the-clock); also, as in the previous RFP, any non-standard products received were also considered. The EAA RFP sought energy for the period September 1, 2025 through September 1, 2026. The RFP was sent to [REDACTED]

██ NSPI received offers from ██████ counterparties ██████
 ██████ submitted a single offer with offerings in each of the twelve months, while ██████
 submitted 7x24 and 5x16 offers for March 2026 only. ██████ offers were for firm generation, ██████

[REDACTED]

NSPI again used PLEXOS to evaluate the bids.

[REDACTED]

[REDACTED]. In our view, this was a reasonable outcome.

[REDACTED]

[REDACTED]

[REDACTED] The bottom rows of the figure provide the combined results across all offers and winning offers.

[illegible]

XII.B.1.d.iii.3. Surplus Energy Received

We next reviewed the volumes of energy that actually flowed pursuant to the winning offers in the [REDACTED] EAA RFPs. The figure below shows the results for the 2024 EAA RFP. Specifically, NSPI received a total of [REDACTED] GWh of Surplus Energy from [REDACTED] over the September 1, 2024-August 31, 2025 period. This is only about [REDACTED] % of [REDACTED] (all of which was selected in the RFP) of [REDACTED] GWh. Results for off-peak energy ([REDACTED] % of accepted volumes flowed) were moderately better than on-peak results ([REDACTED] % of accepted volumes flowed). NSPI accepted [REDACTED] GWh of on-peak winter volumes for months November 2024 through March 2025, but received [REDACTED] GWh during that period. For comparison's sake, NSPI received [REDACTED] GWh of on-peak and [REDACTED] GWh of off-peak energy from [REDACTED] pursuant to its selected offers, or about [REDACTED] % and [REDACTED] %, respectively.

Figure XII-16: Actual Flows vs. Accepted Volumes (Surplus Energy, 2024 EAA RFP)

Month	On-Peak EAA Offer (GWh)	On-peak Deliveries (GWh)	% Delivered	Off-Peak EAA Offer (GWh)	Off-peak Deliveries (GWh)	% Delivered	Total EAA Offer (GWh)	Total Deliveries (GWh)	% Delivered
Sep-24									
Oct-24									
Nov-24									
Dec-24									
Jan-25									
Feb-25									
Mar-25									
Apr-25									
May-25									
Jun-25									
Jul-25									
Aug-25									
Total									

The next figure below shows the results for the 2025 EAA RFP. To date (through March 2026), NSPI has received a total of [REDACTED] GWh of Surplus Energy from [REDACTED] over the September 1, 2025-March 31, 2026 period. This is about [REDACTED] % of [REDACTED] EAA offer over that same period (all of which was selected in the RFP) of [REDACTED] GWh. (In total, [REDACTED] total offer for the full year was [REDACTED] GWh, all of which was selected in the RFP.) This time, results for on-peak energy have been stronger ([REDACTED] % of all accepted volumes have flowed) than off-peak energy ([REDACTED] % of selected volumes have flowed). On-peak winter volumes have been particularly strong: NSPI accepted [REDACTED] GWh for months November 2025 through March 2026 and received [REDACTED] GWh during that period, or [REDACTED] %.

[illegible]

Age Group	Percentage of Respondents
18-29	95%
30-49	93%
50-64	91%
65+	85%

⁷⁰² EAA, Schedule 1, section 4.1.

[REDACTED]

We verified a sample invoice showing that prices invoiced to NSPI were Mass Hub day-ahead prices for delivered Surplus Energy. In 2024, NSPI was invoiced for [REDACTED] GWh at \$ [REDACTED] (excluding tax), or \$ [REDACTED]/MWh. In 2025, NSPI was invoiced for [REDACTED] GWh at \$ [REDACTED] (excluding tax), or \$ [REDACTED]/MWh.

We also reviewed NLH's compliance with the EAA requirement that it make available to NSPI an average of 1.2 TWh per year over the 35-year term of the EAA.⁷⁰⁵ [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Finally, we note that during the Audit Period, NSPI purchased 330 GWh of RECs from NLH, all of which was associated with Surplus Energy. NSPI paid \$ [REDACTED]/REC (2024) and \$ [REDACTED]/REC (2025). As we explain in Chapter X, these purchases were necessary for NSPI to meet its RES requirements in both 2024 and 2025. Going forward, NSPI's ability to purchase RECs from NLH associated with Surplus Energy could be valuable, though is subject to bilateral price risk since NSPI and NLH do not have a formal agreement specifying the price of RECs.

XII.B.1.e. Final Audit Period Data for Imported Power

In all, NSPI imported 5,030,187 MWh of power during the Audit Period, [REDACTED] % of which was imported in 2024 ([REDACTED] MWh) and [REDACTED] % of which was imported in 2025 ([REDACTED] MWh). About [REDACTED] % of all imported power was imported from Newfoundland, with the other [REDACTED] % being imported over the New Brunswick tie. Specifically, NSPI imported a total of [REDACTED] MWh over the Maritime Link, [REDACTED] % of which was in 2024 ([REDACTED] MWh) and [REDACTED] % was in 2025 ([REDACTED] MWh). NSPI imported a total of [REDACTED] MWh over the tie with New Brunswick, [REDACTED] % of which was in 2024 ([REDACTED] MWh) and [REDACTED] % was in 2025 ([REDACTED] MWh).

⁷⁰³ 2024 Maritime Link Benefits Report Q4, Figure 2.

⁷⁰⁴ 2025 Maritime Link Benefits Reports (Q1-Q4).

⁷⁰⁵ EAA, section 4.1 (a).

NSPI appeared to maximize its use of its intertie with Newfoundland during the Audit Period. As already explained, NSPI received substantial volumes of NS Block, including makeup energy, such that the longstanding deficit in deliveries was fully erased by November 2024. Moreover, NSPI selected about █ TWh of Surplus Energy offered by █ in NSPI's █ held during the Audit Period. While actual Surplus Energy flows through March 2026 have only been slightly more than half (approximately █%) of EAA Surplus Energy selected through this same time frame in the RFPs, we observed no evidence that NSPI is responsible for these lesser flows.

Further to this point, we reviewed capacity and flow data on the Maritime Link and the LIL, as well as Muskrat Falls' generation during the Audit Period. Across all hours, the █ MW Maritime Link's average capacity was █ MW and the actual average hourly flow was █ MW, or about █% of its average capacity. The highest hourly flow during the Audit Period was approximately █ MW, █ of the Maritime Link's capacity of █. NSPI explained that the Maritime Link's "peaking capacity" is 475 MW and expected to be used sparingly due to regional simultaneous import limits, intermittent renewable generation integration in Nova Scotia, and economic considerations.

Regarding the LIL, it averaged bipole capacity of █ MW across the Audit Period, with an average hourly flow of █ MW, or about █% of its average capacity. The highest hourly flow was approximately █ MW. Throughout the Audit Period, the maximum transfer capability of the LIL was █ MW, below its design specified maximum of █ MW. NSPI explained that NLH's high-power testing of the LIL to operate at █ MW was still ongoing as of the end of the Audit Period.

Lastly, regarding Muskrat Falls, it produced an average hourly output of █ MW (compared to its nameplate capacity of █ MW). Its maximum hourly output during the Audit Period was approximately █ MW.

Looking deeper at the data, the flows on the LIL were *less* than the hourly output of Muskrat Falls in about █% of all hours during the Audit Period, with an average hourly deficit equaling █ MW when considering all hours of the Audit Period. This may imply that a higher LIL capacity (to █ MW) could lead to greater flows on the line, which could translate to higher Surplus Energy volumes for NSPI. However, NSPI's position is that the limitation of the LIL to █ MW has not been a limiting factor in the utilization of the Maritime Link and importation of energy from Muskrat Falls to Nova Scotia. NSPI notes that the nature of the Muskrat Falls nameplate capacity (█ MW) compared to the LIL capability (█ MW) demonstrates that the frequency of reliance on the full capability of the LIL should be infrequent. We do not disagree, and would expect that in most hours, the increased capability of the LIL from █ MW to █ MW may not have a material impact on NSPI and its customers. However, during periods of highest demand, this additional capability may be helpful, as it would allow NLH to meet its native load obligations in Newfoundland and increase the likelihood of surplus Muskrat Falls energy to export to Nova Scotia. NSPI indicated that NLH successfully completed high power testing on the LIL in March 2026, and NSPI expects the LIL to formally update its rating to █ MW in the near term.

XII.B.2. Power Exports

NSPI’s energy marketers also export power on a short-term basis—i.e., day-ahead or real-time. In general, these export opportunities fall into two categories, but both categories are based on economics. One set of transactions is related to instances where the price for power elsewhere is higher, net of all transmission and tariff fees, than the cost to produce power in Nova Scotia. A second set involves periods of high wind output, whereby the Nova Scotia system has excess energy. In these cases, NSPI marketers look to sell this excess energy and renewable energy credits (“RECs”) to generate revenue, as an alternative to curtailment.

To determine whether a potential export is economic, marketers compare NSPI’s system cost to produce the next increment of power using its own generation (using GenCost) with the expected revenue of the export sale. As with imports, export transactions with New England must be executed at least two hours in advance, meaning that variables that may change in such a way that although a transaction looks economically beneficial at the time the marketer executes it, market price movements could cause the transaction to become uneconomic.

Figure XII-18 below summarizes NSPI’s exports during the Audit Period. NSPI exported almost no energy during the Audit Period. Total volumes of exports were just 4.5 GWh, an amount that corresponded to approximately 0.02% of its total system requirements during the Audit Period. There were [REDACTED] exports from South Canoe,⁷⁰⁶ and NSPI sold [REDACTED] RECs in export markets during the Audit Period. Export sales of energy and RECs generated revenue of [REDACTED] million and gains of under [REDACTED] million.

Figure XII-18: NSPI’s Short-Term Exported Power Volume, Cost⁷⁰⁷

Year	Volume (MWh)	Volume as % of TSR	Total Revenue	Total Cost	Gain (Loss)
2024	0	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2025	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

During the Audit Period, NSPI’s exports involved [REDACTED] counterparties: [REDACTED]
[REDACTED]

Figure XII-19 shows all export transactions during the Audit Period, broken down by counterparty.

⁷⁰⁶ Q4 2025 FAM Report, 7(3).

⁷⁰⁷ Data compiled from Q4 2025 FAM Report, 2(3) and 7(3).

Figure XII-19: NSPI's Power Exports, by Listed Counterparty⁷⁰⁸

Counterparty	2025		
	Number of Transactions	Transaction Volume	Weighted Average Price (USD/MWh)

As with imports, we sampled several of NSPI's export transactions during the Audit Period. Our goal was to determine if NSPI's marketers were entering into export transactions that were expected to be beneficial to its customers. We say "expected" because the export with New England involves estimates of NSPI's system marginal energy cost, ISO New England's expected energy prices (ISO New England requires all import transactions to be secured two hours ahead of energy flow), and also Massachusetts Class 1 REC prices, which also must be estimated. Second, given that the realized results may differ from the expected results at the time the transaction was executed, we wanted to know if, on net, NSPI's exports are resulting in savings to customers. Importantly, the first step here involves looking at the prudence of the marketers: given the information known at the time of the transaction, was the transaction expected to produce savings for ratepayers? And in the second step, we are testing the efficacy of NSPI's entire export approach—that is, not just whether marketers are prudent, but also whether NSPI's process—which must include estimation and, in some cases, the risk of price movements in the two hours from transaction to energy flow—is working.

Like with import transactions, there are numerous costs – some known, some unknown – that factor into NSPI's decision-making. For exports that involve the New Brunswick transmission system, NSPI must pay CAD \$9.36/MWh for on-peak power and CAD \$4.45/MWh for off-peak power. ISO New England transactions were assessed fees of USD \$0.49/MWh. Therefore, for an export to be economic, it must be so including all of these various charges—in addition to the cost of the export itself.

[REDACTED]

XII.B.3. Affiliate Transactions

NSPI's purchase and sale of power involves three different affiliate transaction types: (a) power import/export transactions in which NSPEMI transacts on NSPI's behalf; (b) purchases from the

⁷⁰⁸ Quantities may not add up to aggregate data provided in NSPI's quarterly FAM reports. This is due largely to transactions in which power does not flow (or is de-rated) as a result of actions by system operators to reduce or cut scheduled transactions because of insufficient transmission capability or for reliability reasons. Also, data includes REC sales as MWh amounts, while the quarterly FAM reports do not.

Brooklyn Power facility, owned by Emera; and (c) payments to NSPML for Maritime Link charges. (Natural gas affiliate transactions are addressed in Chapter VIII.) We address each in this section.

XII.B.3.a. NSPEMI

NSPEMI is an affiliate of NSPI created to allow NSPI to transact for power and natural gas in the United States without the use—and added cost—of an agent. While technically an affiliate, NSPEMI's operations are conducted solely by NSPI employees, and the power and REC transactions NSPEMI executes are executed by NSPI's ERM employees. Recognizing this unique arrangement, NSPI proposed—and the Board approved—a flow-through pricing protocol that was not already contemplated within the Affiliate Code of Conduct.⁷⁰⁹ The Code of Conduct does, however, allow for use of “a pricing protocol other than those described [in the Affiliate Code of Conduct]” as long as the proposed pricing protocol received Board approval. NSPI proposed the flow-through protocol pursuant to section 6.18 of the Code of Conduct, stating that:

NSPEMI will be responsible for payment of all costs and expenses including those related to import transactions, and will receive any revenue associated with the export transactions. There would be no charge for the labour carried out by NS Power employees on behalf of NSPEMI. Once the information has been recorded appropriately, NSPEMI will look to NS Power for reimbursement of costs and expenses or will pay NS Power any revenues. These transactions will be treated like flow-through costs and will be market-based. Neither NS Power nor NSPEMI will be charging or paying fully allocated costs with respect to these transactions. All pricing will be market-based and will reflect the prices that NS Power and NSPEMI have been able to obtain for customers. As this would be an exception to the pricing protocol set out in section 6.7 of NS Power's Affiliate Code, NS Power requests UARB approval for exception to the pricing protocol.⁷¹⁰

We reviewed NSPEMI's import and export transactions and costs and found NSPI in compliance with the Affiliate Code of Conduct and the pricing protocol approved by the Board. All transactions were executed by ERM employees and were subject to the oversight of existing NSPI management, as promised by NSPI in its NSPEMI application to the Board.

XII.B.3.b. Brooklyn Power

Brooklyn Power is a 30-MW biomass generator located in Liverpool, Nova Scotia that uses a conventional steam turbine fueled primarily by wood, but that can also be powered by fuel oil. The PPA that underlies the Brooklyn Power facility was signed on June 30, 1992, and will expire in 2028. The original counterparty to the PPA was Polsky Energy Corporation. In 2013, the PPA was assigned to Brooklyn Power Corporation, which is owned by Emera Inc. The PPA is an exception to the Affiliate Code and is governed by the terms of the PPA.

⁷⁰⁹ NSUARB, “M08911 – Nova Scotia Power Inc. – NS Power Energy Marketing Inc. Pricing Protocol and Provision of Guarantees,” November 29, 2018.

⁷¹⁰ NSPI, “NSP Energy Marketing Inc. – Request for UARB Approval,” M08911, September 28, 2018.

During the Audit Period, Brooklyn Power provided █████ MWh at a total cost of CAD \$█████. Figure XII-20 shows Brooklyn Power's output and cost over the Audit Period.

Figure XII-20: Monthly Output, Costs for Brooklyn Power⁷¹¹

Month	Output (MWh)	Cost (CAD \$)	Implied \$/MWh Cost
January 2024			
February 2024			
March 2024			
April 2024			
May 2024			
June 2024			
July 2024			
August 2024			
September 2024			
October 2024			
November 2024			
December 2024			
January 2025			
February 2025			
March 2025			
April 2025			
May 2025			
June 2025			
July 2025			
August 2025			
September 2025			
October 2025			
November 2025			
December 2025			
Total 2024			
Total 2025			
Total Audit Period			

The volume of output and cost grew considerably from the prior audit period, where NSPI received approximately █████ GWh for just under █████ million over the audit period. The primary reason for this large increase in output and cost was simply a return to consistent normal production; during the prior audit period, a forced outage at Brooklyn caused by a stack collapse⁷¹² began on February 18, 2022 and

⁷¹¹ Costs sourced from NSPI Quarterly Reports, tabs "10", "10 (2)", and "10 (3)". MWh output sourced from tabs "9", "9 (2)", and "9 (3)".

⁷¹² See, Michael Gorman, "N.S. power plant that uses biomass knocked offline after stack falls in high winds," *CBC*, February 22, 2022, available at: <https://www.cbc.ca/news/canada/nova-scotia/emera-energy-brooklyn-biomass-wind-damage-1.6360815>.

lasted until January 31, 2023.⁷¹³ However, costs in this Audit Period were also considerably higher than those in the 2020-2021 audit period (despite similar output from the facility). This was caused by provincial legislation that dictated additional payments from NSPI to Brooklyn (which we explain next). Figure XII-21 below shows the output and cost of Brooklyn Power over the last three audit periods.

Figure XII-21: Output, Costs for Brooklyn Power (prior three audit periods)⁷¹⁴



In December 2022, the *Renewable Electricity Regulations* were amended to include a new section 6AA that required NSPI to recover a minimum of 135 GWh of “dispatchable renewable electricity from a renewable low-impact electricity generation facility located in the Province” and to “pay \$30/MWh for all dispatchable renewable electricity acquired from a biomass generation facility in addition to any price specified in any existing power purchase agreement, up to a maximum of \$4.05 million per year.”⁷¹⁵ Thus, NSPI dispatched Brooklyn as a “must run” unit starting in 2023.⁷¹⁶ In 2024, NSPI received [REDACTED] GWh of energy from Brooklyn⁷¹⁷ and paid a total of \$ [REDACTED] in extra costs (pursuant to the \$30/MWh adder required by the regulation).

In 2025, NSPI continued to pay Brooklyn under this regime for January and February output, which totaled [REDACTED] GWh,⁷¹⁸ and paid an additional \$ [REDACTED] (pursuant to the \$30/MWh adder required by the

⁷¹³ 2022-2023 Bates White Audit Report, page 359.

⁷¹⁴ NSPI Quarterly Reports for Q4 2025, Q4 2023, and Q4 2021, tab “9 (3)” and “10 (3)”.

⁷¹⁵ *Renewable Electricity Regulations*, section 6AA.

⁷¹⁶ 2022-2023 Bates White Audit Report, section XII.B.3.b.

⁷¹⁷ 2024 Q1-4 FAM Report, tabs “9”, “9 (2)”, and “9 (3)”.

⁷¹⁸ 2025 Q1 FAM Report, tabs “9”, “9 (2)”.

regulation). As of March 1, 2025, NSPI is required to pay an amount to Brooklyn that was established by the Board under subclause 18(2)(a)(ii) of the Renewable Energy Standard on all dispatchable renewable electricity acquired from a biomass facility. The regulation specified that this new rate established by the Board “overrides any other payment amount specified in any existing power purchase agreement.”⁷¹⁹ The rate paid by NSPI to Brooklyn was \$ [REDACTED] /MWh. Over the ten months in which this new regime was in place, NSPI received [REDACTED] MWh of energy from Brooklyn⁷²⁰ at a total cost of \$ [REDACTED]. We continue to find the Brooklyn facility to be an expensive source of energy, now made more expensive by the new rate charged to NSPI since March 1, 2025.

XII.B.3.c. NSPML

The Maritime Link is owned by NSPML, a wholly-owned subsidiary of Emera and an affiliate of NSPI. Recovery of Maritime Link costs were subject to Board-approved annual assessments. Revenue of up to \$163.5 million and \$197.2 million was approved for 2024 and 2025, respectively.^{722, 723} NSPI’s total recovery in 2024 was \$161,000,000; in 2025, it was \$195,691,785. The assessments remain subject to “holdbacks” until NSPML can satisfy two conditions: (1) at least 90% of the NS Block, as measured in MWh (excluding Make-up Energy), is received during each of 12 consecutive months, and (2) the net outstanding balance of undelivered energy is less than 10% of the contracted annual amount of the NS Block.⁷²⁴ On February 3, 2026, NSPML filed an application with the Board requesting the end of the revenue holdback mechanism; that application, filed in matter M12696, is pending and is expected to address NSPML’s request to end the holdback mechanism and address funds held back to date. We filed evidence in that proceeding.⁷²⁵

In addition, NSPI reported several other cost and cash inflow entries related to NSPML:

- In 2024, NSPI and NSPML filed an application with the Board to proceed with a commercial agreement with the Government of Canada to provide relief to customers related to the FAM balance (M11791 and M11902). Under this agreement, NSPML issued \$500 million in new debt, which was then refunded to NSPI for the benefit of customers. These funds will be collected from NSPI ratepayers over 28 years. As a result of this agreement, \$485.9 million was credited to the FAM in 2024 and in 2025, after the finalization of financing terms, NSPI received an additional \$10.8 million that was also credited to the FAM.
- In 2024, NSPI recorded a \$ [REDACTED] reduction in Maritime Link costs in recognition of earnings from NSPML that exceeded the 9.25% allowable return on equity.

⁷¹⁹ Renewable electricity standard 2025, section 6AB (4), available at: <https://novascotia.ca/just/regulations/regs/elecrenew.htm>.

⁷²⁰ 2025 FAM Quarterly Reports, tabs “9”, “9 (2)”, and “9 (3)”.

⁷²¹ 2025 FAM Quarterly Reports, tabs “9”, “9 (2)”, and “9 (3)”.

⁷²² “Consolidated Financial Statements,” M12182, March 27, 2025, page 12.

⁷²³ “Consolidated Financial Statements,” M12779, March 27, 2026, page 10.

⁷²⁴ Nova Scotia Utility and Review Board, “Decision,” M11099, October 4, 2023, page 43.

⁷²⁵ See Exhibit N-7, M12696, filed June 11, 2026.

- In 2025, a reduction of \$ [REDACTED] was recorded in Maritime Link costs related to the contingency services agreement that was included in the 2025 assessment cost but did not occur during the year. This refund was committed to by NSPML as part of the 2026 assessment cost application hearing in matter M12394.
- In 2025, Maritime Link costs were reduced by \$ [REDACTED] as a result of changes to the value of make-up energy received in September 2023. As the funds for this holdback period had already been released as per NSEB Decision (M11009), this amount was credited directly to fuel costs.

Figure XII-22 shows the month-by-month breakdown of the costs for the Audit Period.

Figure XII-22: NSPML Assessment, by Month (CAD\$)

Month	2024	2025
January	\$13,625,000	\$16,429,815
February	\$13,625,000	\$16,429,815
March	\$13,625,000	\$16,429,815
April	\$13,625,000	\$16,429,815
May	\$13,625,000	\$19,197,255
June	\$13,625,000	\$17,173,588
July	\$13,625,000	\$16,342,988
August	\$13,625,000	\$16,342,988
September	\$13,625,000	\$16,342,988
October	\$13,625,000	\$16,342,988
November	\$13,625,000	\$16,342,988
December	\$11,125,000	\$11,886,740
Total	\$161,000,000	\$195,691,785

XII.B.4. Bates White's 2022-2023 Audit Recommendations

In our report for the prior Audit Period, we included five recommendations regarding power purchases and sales. We address each as follows.

Our first recommendation was:

Recommendation XII-1: NSPI should continue to update the Board on its progress to come to a final agreement with NLH regarding the valuation of the undelivered NS Block quantities, the classification of the undelivered quantities as either Block A Undelivered Energy or Block B Undelivered Energy, and the precise valuation of the makeup energy that NLH will provide the undelivered quantities. The update should include the quantities and value of the undelivered quantities to date, as well as the quantities and value of any makeup energy provided to date. The data should also clearly explain whether the volumes are “gross” or “net” volumes (i.e., whether transmission losses are included), and ensure that the reported volumes are reported in units that match the contractual obligations of the ECA. Such data should include supporting calculations to encourage transparency. NSPI should continue updating the Board quarterly on this issue until both (a) NSPI and NLH come to such a final agreement and (b) all makeup quantities have been delivered.

NSPI accepted this recommendation and stated that it would “continue to update the Board on progress towards the final determination of Block A and Block B volumes.” We noted in our Rebuttal Evidence that we considered NSPI’s response to be “positive and satisfactory.”⁷²⁶ NSPI stated in their February 2026 update that “NLH and NS Power have met several times and most recently on December 11, 2025” to discuss relevant pieces of the valuation and that “the review process is ongoing.” In section XII.B.1.d.ii above, we address NSPI’s response to this recommendation. We consider NSPI to have adequately responded to this recommendation.

Our second recommendation read:

Recommendation XII-2: NSPI should maintain its pursuit of recovery of missing NS Block energy volumes in a manner that recognizes the contractual provisions pertaining to missing and makeup energy, seeks to maximize value for FAM customers, and addresses the fact that 82,341 MWh of replacement energy received during the Audit Period was not eligible as replacement energy under the ECA’s terms.

NSPI accepted this recommendation and stated that it would “[agree] to continue its pursuit of missing NS Block energy in a way that recognizes the contractual provisions pertaining to missing and makeup energy, and the maximizing of value for FAM customers, and [would] provide further detail and context on the identified 82,341 MWh of energy, including how the approach for receiving this energy brought value to customers.” We noted in our Rebuttal Evidence that we considered NSPI’s response to be “positive and satisfactory.”⁷²⁷ We address NSPI’s response to this recommendation above in section XII.B.1.d.ii. We consider NSPI’s response to be adequate.

Our third recommendation read:

Recommendation XII-3: NSPI should continue its efforts to accurately value the missing and makeup NS Block energy volumes. NSPI should maintain its existing reporting to the Board but should enhance that reporting to adjust its Hourly Replacement Method as needed, particularly as it relates to solid fuel costs (which can use forward replacement costs that are not incurred). NSPI should not abandon the Hourly Replacement Method given its attributes. NSPI should include in its reporting the determination of Block A and Block B volumes and valuations so stakeholders and the Board understand the full picture of NS Block undelivered and makeup volumes and values. NSPI should continue reporting these valuations quarterly and should do so until NSPI has ceased receiving makeup energy.

NSPI accepted this recommendation and stated that it would “complete the valuation of the missing and makeup NS Block energy volumes for review by Bates White over the Q4 2024 to Q1 2025 period, during which the remaining makeup energy (approximately ■ MWh) is expected to be received. NS Power [would] maintain its existing quarterly reporting to the Board and enhance the report as necessary based on this review.” We noted in our Rebuttal Evidence that we considered NSPI’s response to be

⁷²⁶ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 19.

⁷²⁷ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 19.

“positive and satisfactory.”⁷²⁸ In section XII.B.1.d.ii above, we address NSPI’s response to this recommendation. We consider NSPI to have adequately responded to this recommendation.

Our fourth recommendation read as follows:

Recommendation XII-4: NSPI should consider pursuing the long-term capacity value of the undelivered quantities of NS Block from NLH, conservatively estimated at the carrying cost of Lingan 2.

NSPI accepted this recommendation and stated that it would “consider available approaches to recovering the long-term capacity value of the undelivered quantities of NS Block,” noting additionally that “[a]ny analysis of NS Power’s legal rights and obligations under the EAA” and “[s]pecific matters in relation to the Muskrat Falls Project and associated contracts are considered privileged.” We noted in our Rebuttal Evidence that we considered NSPI’s response to be “positive and satisfactory.”⁷²⁹ NSPI did not recover any value associated with the long-term capacity value of the NS Block from NLH, nor does it appear NSPI will be able to do so at any point. NSPI has never agreed with our view that there was a loss of value. As we explained:

There is one aspect of NSPI’s approach that we do not agree with. In our view, there is one piece of the NS Block value proposition that will not be delivered with the makeup volumes contemplated by NSPI. Specifically, the long-term capacity value of the NS Block will not be made up under NSPI’s planned approach. NSPI acknowledges that the long-term capacity value of the NS Block is 153 MW of installed capacity and 150 MW of unforced capacity, which is based on effective load carrying capability of 98%. However, during the August 2021 through December 2021 portion of the Audit Period, and indeed into 2022, NSPI has not been receiving 153 MW of installed capacity from the NS Block; rather, the NS Block has been subject to frequent and extended capacity reductions, in some cases reducing capacity to zero for a period as long as one month.

It is true that the makeup energy volumes NSPI will receive are subject to scheduling provisions in Schedule 5 of the ECA that require [NLH] to submit medium-term forecasts of the makeup energy [NLH] could provide. NSPI indicated that it was receiving schedules from [NLH] extending 6 to 8 months into the future, showing [NLH’s] capability for providing makeup energy during that period. We observed evidence of [NLH’s] advanced schedule offerings. We acknowledge that it is helpful and valuable to know months in advance an available schedule of additional firm energy on which NSPI could rely at its option. Knowing that, for example, NSPI would receive 100 MW of makeup energy above and beyond the NS Block volumes for a given day could mean that NSPI would not have to commit one or more resources to be online that day. This can drive savings for customers.

However, missing from this “capacity” value is a consideration of one piece of the overall Maritime Link/NS Block value proposition. NSPI had plans to fully replace the 153 MW Lingan 2 unit with 153 MW of firm peak energy from the NS Block. During the period of substantial underdeliveries which will continue until the Labrador Island Link truly reaches complete

⁷²⁸ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 19.

⁷²⁹ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 6 line 19.

commercial operations, NSPI cannot count the full 153 MW of NS Block capacity toward its planning reserve margin—in fact, it is unlikely that NSPI would be able to rely on any of that 153 MW toward its planning reserve at all, considering its experience in October 2021 when the Labrador Island Link's unavailability meant zero MWhs flowed during the 31-day month.

Moreover, once the Labrador Island Link is fully commissioned and NSPI is regularly receiving its full NS Block with no material underdeliveries, NSPI can then fully count the NS Block toward its planning reserve margin and take steps elsewhere in its fleet to reduce costs related to redundant assets, such as the planned retirement of Langan 2. The makeup energy NSPI receives from [NLH] will not provide any incremental long-term capacity value. For example, if NSPI receives 25 MW of additional NS Block quantities every other week for a year, this would not allow NSPI to retire any additional resources or even consider a seasonal layup of a given resource to cut down on variable costs. We believe this is a material loss for FAM customers.

NSPI does not agree with our assessment. First, NSPI made it clear that they do not believe FAM customers have been or will be deprived of any long-term capacity value resulting from the undelivered NS Block quantities. NSPI indicated that in its view, the NS Block as currently being delivered meets the standards for being considered capacity since (a) the NS Block is fully dedicated to NSPI and cannot be called upon by any other purchaser and (b) the NS Block has firm transmission interconnecting the source to NS Power. We do not dispute NSPI's statements here, but simply reiterate that these points ignore the fact that until the NS Block is being fully delivered following full commissioning of the Labrador Island Link, NSPI will be unable to rely upon the 153 MW of ICAP and 150 MW of UCAP promised by the project. And since the term of ECA has begun as of August 15, 2021 and has a finite term of 35 years, each day that passes is another day FAM customers do not receive the planning reserve margin benefits of the NS Block.

We turn next to the question of the long-term capacity value of which FAM customers are being denied. A conservative view of this value would be the carrying cost of Langan 2, the unit slated to retire in concert with the full commissioning of the NS Block. Thus, we recommend that NSPI's pursuit of additional compensation from [NLH] consider including the carrying cost of Langan 2 from August 15, 2021 through the day before the ultimate full commissioning of the Labrador Island Link and NS Block. Thus, if the Labrador Island Link is fully commissioned on August 15, 2022, one year after the start date of the NS Block, and the carrying cost of Langan 2 for one year is \$4.0 million, our recommendation would be that NSPI should consider this additional \$4.0 million in its pursuit of NS Block replacement quantities from [NLH].⁷³⁰

Given that we have made this recommendation in two consecutive audits, we do not include a recommendation on this matter any further. Our position remains that there was a loss of value that has not been made up, though we also acknowledge that there is no direct contractual vehicle for demanding compensation from NLH. Moreover, we would note that even as NS Block volumes have greatly increased and stabilized, Langan 2 remains unretired. This suggests that even if NSPI had received the capacity value of the NS Block starting in 2021, NSPI would not have retired Langan 2 and still incurred its carrying costs. Finally, our recommendation was modest, requiring only that NSPI "consider" pursuing the lost capacity value. As such, we consider this recommendation to be addressed.

⁷³⁰ 2020-2021 Bates White Audit Report, pages 312-313.

Our fifth recommendation read:

Recommendation XII-5: NSPI should either (a) enforce the identified provisions of the Brooklyn PPA or (b) pursue reasonable PPA revisions that better match how the PPA is administered.

NSPI accepted this recommendation, providing no further detail regarding approach. We noted in our Rebuttal Evidence that “NSPI should provide additional detail about how it will implement this recommendation.”⁷³¹ In its February 2026 update, NSPI stated that NS Power and Brooklyn Power executed two amendments in December 2023 and December 2024 “to formalize the amendments concerning Renewable Electricity Regulations sections 6AA (1), (2) and (3) of the Electricity Act” and relating to the “codification of existing practices between NS Power and Brooklyn Energy,” respectively.

On December 22, 2025, NSPI and Brooklyn Power executed an additional amendment to the PPA.⁷³² The amendment addresses pricing changes for 2025-2027 related to the pricing contained in the revised Renewable Electricity Regulations requiring that NSPI pay Brooklyn “the tariff energy rate established pursuant to subclause 18(2)(a)(ii) of the RES Regulations for dispatchable renewable electricity acquired from the Facility that is sold and delivered by the Seller to NSPI at the Delivery Point, rather than the applicable rates for such energy otherwise specified by provisions of [the PPA].”⁷³³ The amendment refers to the energy acquired from Brooklyn as “6AB Energy,” which is the dispatchable renewable electricity that NSPI acquires pursuant to Section 6AB(1) of the RES Regulations.”⁷³⁴ The amendment, which had an effective date of March 1, 2025, notes that if at any point during the 2025-2027 period, “there are one or more vendors” from whom NSPI can acquire dispatchable renewable electricity, NSPI must “acquir[e] from Seller and any Qualifying Vendors the 6AB Energy in the manner most economical for its customers.”⁷³⁵ The amendment also notes that “the Parties have had discussions regarding certain additional aspects of the PPA that may warrant amendment” and that the parties “will conduct negotiations through which they may reach agreement on additional binding amendments to the PPA to reflect these matters.”⁷³⁶

NSPI has fully addressed our prior audit recommendation on this topic, and through its December 22, 2025 amendment, has further updated its PPA.

⁷³¹ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 12 lines 6-7.

⁷³² “Brooklyn Power - 20251222 PPA Amending Agreement.”

⁷³³ “Brooklyn Power - 20251222 PPA Amending Agreement,” section 5.7 (a).

⁷³⁴ “Brooklyn Power - 20251222 PPA Amending Agreement,” section 3 (a).

⁷³⁵ “Brooklyn Power - 20251222 PPA Amending Agreement,” section 5.7 (b)(i).

⁷³⁶ “Brooklyn Power - 20251222 PPA Amending Agreement,” PDF page 1.

XII.C. Conclusions

Conclusion XII-1: The sources of power that serve FAM customers continue to become more diverse and regionally-integrated as evidenced by continued increases in imports and third-party purchases, totaling 35.9% during the Audit Period.

Conclusion XII-2: Pursuant to provincial law and programs, NSPI is party to a large number of PPAs with small renewable generators with administratively-set pricing that is generally high on a \$/MWh basis.

Conclusion XII-3: NSPI executed several new PPAs for solar and wind at the direction of the Minister of Natural Resources and Renewables. NSPI is obligated in such instances to execute and administer such contracts.

Conclusion XII-4: NSPI extended existing PPAs with [REDACTED] (for 33 months) and [REDACTED] (for 10 years). NSPI's decisions regarding these extensions were supported by alternatives analysis and reasonably attempted to capture the costs and benefits of the resources and their alternatives. It would be preferable for resources like these (and their alternatives) to compete to provide renewable energy to NSPI, not be subject to one-off, alternatives analysis comparisons. Going forward, the IESO will be responsible for this function and will hopefully embark upon improvements to introduce best-practices competitive procurement to the province for the benefit of FAM customers. As such, we do not include a recommendation on this point.

Conclusion XII-5: NSPI issued two RFPs for power during the Audit Period, each issued under the requirements of the EAA.

Conclusion XII-6: Approximately [REDACTED]% of NSPI's total system requirements was provided by imported power. In comparing Audit Period results to those of the previous period, import volume is 6% higher than the previous Audit Period. This is the result of deliveries of larger amounts of Muskrat Falls energy delivered via the Maritime Link.

Conclusion XII-7: NSPI was a net importer of power in all 24 months over the intertie with New Brunswick.

Conclusion XII-8: NSPI's short-term energy marketing transactions provide benefits to FAM customers, either in the form of economics (i.e., lowering FAM costs) or reliability. This was confirmed in Audit Period transaction sampling.

Conclusion XII-9: NSPI imported power for reliability purposes on [REDACTED] days during the Audit Period. The total volume of reliability transactions was 5,185 MWh, with an average price of \$[REDACTED]/MWh.

Conclusion XII-10: The highest priced reliability import was \$[REDACTED]/MWh, which was the second hour of a four-hour real-time import from ISO New England. NSPI acted reasonably, and despite the high prices in New England at the time, the transaction actually saved USD \$[REDACTED] given the ultimate real-time prices in New England and the system cost in Nova Scotia.

Conclusion XII-11: Entering the Audit Period, NSPI was owed a balance of 201,779 MWh of undelivered Base Block energy and 54,833 MWh of Supplemental Block. On June 22, 2024, the undelivered Base Block volume net of makeup energy received reached zero for the first time, while on November 21, 2024, the undelivered Supplemental Block volume net of makeup energy received also reached zero for the first time. Since those dates, undelivered volumes have been minimal, with NSPI suffering material underdeliveries in three months (August 2024, September 2024, and September 2025), which occurred largely due to planned maintenance activities on the LIL which NSPI explained were scheduled for periods of lower system load and lower replacement energy costs. In all cases, makeup volumes were received relatively promptly.

Conclusion XII-12: NSPI received 1,666,975 MWh of Base Block, which was approximately 85 percent of the contract volume of 1,972,075 MWh. NSPI also received 506,086 of make-up Base Block energy. Factoring in the 201,779 MWh of undelivered Base Block energy as of the beginning of the Audit Period, the total of undelivered Base Block volumes at the end of the Audit Period was 793 MWh.

Conclusion XII-13: NSPI received 519,728 MWh, which was approximately 97 percent of the contract volume of 533,453 MWh. NSPI also received 75,355 MWh of make-up Supplemental Block energy. Factoring in the 54,833 MWh of undelivered Supplemental Block energy as of the beginning of the Audit Period, NSPI enjoyed a surplus of 6,797 MWh of Supplemental Block energy at the end of the Audit Period.

Conclusion XII-14: NSPI and NLH agreed that all undelivered volumes *during the Audit Period* were Block A volumes. However, the parties remain in dispute regarding classification of 61.2 GWh of “undelivered” Base Block energy that accrued during the August-December 2021 timeframe. NSPI claims that this volume should be considered Block B energy, while NLH argues it should be Block A. While the volumes themselves have long been since redelivered, the classification of these volumes matters. If Block A, NLH has already met its obligations under the ECA. If Block B, NLH owes NSPI “compensation energy” in the form of 120% of the undelivered volumes, or an additional 12.2 GWh, which NSPI values at approximately [REDACTED] million. NSPI provided evidence of negotiations between the parties, but the parties remain at an impasse. Under the ECA, the parties are required to negotiate a solution, and barring that, proceed to mediation. If that fails, the parties either agree to an arbitration procedure or litigation. In our view, NSPI has reasonably pursued this issue and we include a recommendation that NSPI update the Board upon resolution. **(Recommendation XII-1)**

Conclusion XII-15: NSPI worked constructively and collaboratively with Bates White regarding the determination of the value of the undelivered and makeup volumes of NS Block. Following extensive meetings and exchanges, NSPI and Bates White agree on the valuation of the makeup energy value (\$[REDACTED] million) but differ on the value of the undelivered volumes (NSPI’s estimate is \$[REDACTED] million, Bates White’s is \$[REDACTED] million). NSPI therefore calculates a net benefit for FAM customers of \$[REDACTED] million, while Bates White calculates a net cost of \$[REDACTED] million. Both parties agree that in addition to these costs and benefits, FAM customers benefited from the timing of the makeup volumes due to the stricter sulfur compliance regime in place during receipt of much of the makeup energy, relative to the

period of undelivered energy. Bates White also agrees that the ECA does not contain any requirement that FAM customers receive any particular monetary value for makeup energy, only that makeup volumes be delivered in the same period (peak for Base Block, off-peak, winter months for Supplemental Block) as the undelivered volumes.

Conclusion XII-16: NSPI provided support for the reasonableness of its decision to receive 82,341 MWh of makeup Supplemental Block energy in non-winter months (April-June 2022), rather than to wait until November-December of 2022 to receive those makeup volumes. This analysis helps demonstrate the reasonableness of NSPI's decision at the time.

Conclusion XII-17: As of the end of March 2026, NSPI will no longer receive 240 GWh/year of Supplemental Block volumes due to the natural expiration of the five-year delivery term of that product under the ECA. Loss of this [REDACTED] energy resource will mean higher FAM costs for customers, roughly estimated by NSPI to be in the range of \$ [REDACTED] million/year.

Conclusion XII-18: NSPI issued two annual RFPs under the EAA during the Audit Period. NLH responded to both RFPs, as did NBEM. Notwithstanding the procurement decisions, NSPI appears to have executed its responsibilities under the EAA.

Conclusion XII-19: In the first EAA RFP, NSPI selected 100% of [REDACTED] offer of [REDACTED] GWh and [REDACTED] offer for [REDACTED]). In our view, this was a reasonable outcome. [REDACTED] to provide substantial benefits relative to the alternative of buying exports out of ISO New England's Salisbury node (as opposed to the Mass Hub node), plus basis, export fees, transmission costs, and losses. NSPI explained that the Salisbury node is the basis node for settling bilateral transactions with [REDACTED]. However, with EAA purchases, NSPI pays only the Mass Hub price and no additional fees, costs, or losses, making it more attractive.

Conclusion XII-20: In the second EAA RFP, NSPI selected [REDACTED]. In our view, this was a reasonable outcome. The [REDACTED] offers, which were limited to March 2026 only, were not forecasted to provide benefits to customers. The [REDACTED] offers, on the other hand, showed large forecasted benefits, plus the additional benefits of being zero emissions and potentially RES-compliant (should NSPI purchase associated RECs separately). While the modeling showed that only [REDACTED], under the EAA, NSPI has the ability to negotiate lower scheduled flows throughout the year, [REDACTED].

Conclusion XII-21: Regarding actual flows related to the first EAA RFP, NSPI received a total of [REDACTED] GWh of Surplus Energy from [REDACTED] over the September 1, 2024-August 31, 2025 period. This is only about [REDACTED] % of [REDACTED] EAA offer (all of which was selected in the RFP) of [REDACTED] GWh. NSPI accepted just [REDACTED] GWh of on-peak winter volumes for months November 2024 through March 2025, but received [REDACTED] GWh during that period. For comparison's sake, NSPI received [REDACTED] GWh of on-peak and [REDACTED] GWh of off-peak energy from [REDACTED] pursuant to its selected offers, or about [REDACTED] % and [REDACTED] %, respectively.

Conclusion XII-22: Regarding actual flows related to the second EAA RFP, to date (through March 2026), NSPI has received a total of [REDACTED] GWh of Surplus Energy from [REDACTED] over the September 1, 2025-March 31, 2026 period. This is about [REDACTED] % of [REDACTED] EAA offer over that same period (all of which was selected in the RFP) of [REDACTED] GWh. Results for on-peak energy have been stronger ([REDACTED] % of all accepted volumes have flowed) than off-peak energy ([REDACTED] % of selected volumes have flowed). On-peak winter volumes have been particularly strong: NSPI accepted [REDACTED] GWh for months November 2025 through March 2026 and received [REDACTED] GWh during that period, or [REDACTED] %.

Conclusion XII-23: Section 2.6 of the EAA requires NSPI to “purchase and receive” all Surplus Energy selected in the annual EAA RFP, though may decline to accept or schedule certain EAA volumes on a day-ahead basis when system constraints (e.g., low Nova Scotia load and/or high wind generation) make acceptance of the full volume infeasible. When NSPI declines to accept EAA energy, NSPI must facilitate transmission of NLH energy through its system. NSPI received \$[REDACTED] for through-and-out transmission sales to NLH in 2024 and \$[REDACTED] in 2025.

Conclusion XII-24: In assessing NLH’s compliance with the EAA requirement that it make available to NSPI an average of 1.2 TWh per year over the 35-year term of the EAA, NSPI clarified in discussions that it does not consider NLH’s annual EAA RFP offers in assessing this metric, but rather considers what is made available to NSPI on a day-ahead basis. This is a highly material point, and we agree with NSPI’s interpretation, as it prevents NLH from meeting its average 1.2 TWh/year offer requirement through a high annual EAA offer that can then be pared down later. Still, given the nature of this offer requirement, which is a 35-year average, it would be prudent for NSPI to begin reporting its tracking of NLH’s compliance with this requirement. To that end, we include a recommendation that NSPI report in its FAM Annual Report NLH’s average Surplus Energy offered to date, as of the end of the most recent EAA contract year. Reporting this to the Board and stakeholders will mitigate the possibility of a surprise contractual dispute later on in the administration of the EAA. **(Recommendation XII-2)**

Conclusion XII-25: NSPI purchased 330 GWh of RECs from NLH, all of which was associated with Surplus Energy. NSPI paid \$[REDACTED]/REC (2024) and \$[REDACTED]/REC (2025). Going forward, NSPI’s ability to purchase RECs from NLH associated with Surplus Energy could be valuable, though is subject to bilateral price risk since NSPI and NLH do not have a formal agreement specifying the price of RECs.

Conclusion XII-26: In all, NSPI imported 5,030,187 MWh of power during the Audit Period, [REDACTED] % of which was imported in 2024 ([REDACTED] MWh) and [REDACTED] % of which was imported in 2025 ([REDACTED] MWh). About [REDACTED] % of all imported power was imported from Newfoundland, with the other [REDACTED] % being imported over the New Brunswick tie. Specifically, NSPI imported a total of [REDACTED] MWh over the Maritime Link, [REDACTED] % of which was in 2024 ([REDACTED] MWh) and [REDACTED] % was in 2025 ([REDACTED] MWh). NSPI imported a total of [REDACTED] MWh over the tie with New Brunswick, [REDACTED] % of which was in 2024 ([REDACTED] MWh) and [REDACTED] % was in 2025 ([REDACTED] MWh).

Conclusion XII-27: NSPI appeared to maximize its use of its intertie with Newfoundland during the Audit Period. We observed no evidence that NSPI is responsible for these lesser flows.

Conclusion XII-28: The Maritime Link’s average hourly flow was █ MW, about █% of its average hourly capacity, and its maximum hourly flow was approximately █ MW. Average bipole hourly flow on the LIL (█ MW) was about █% of its average capacity, with a maximum hourly flow of approximately █ MW. Muskrat Falls hourly generation averaged approximately █ MW and reached a maximum of about █ MW.

Conclusion XII-29: The flows on the LIL were less than the hourly output of Muskrat Falls in about █% of all hours during the Audit Period, with the average hourly deficit equaling █ MW when considering all hours of the Audit Period. This may imply that a higher LIL capacity (to █ MW) could lead to greater flows on the line, which could translate to higher Surplus Energy volumes for NSPI. In most hours, the increased capability of the LIL from █ MW to █ MW may not have a material impact on NSPI and its customers. However, during periods of highest demand, this additional capability may be helpful, as it would allow NLH to meet its native load obligations in Newfoundland and increase the likelihood of surplus Muskrat Falls energy to export to Nova Scotia.

Conclusion XII-30: NSPI engaged in limited power exports during the Audit Period, with all transactions occurring in September and October of 2025. Our sample of NSPI’s power exports showed all exports involving fixed price sales to NLH at prices that exceeded NSPI’s system cost and thus generated benefits for FAM customers.

Conclusion XII-31: NSPEMI’s power import and export transactions and costs were in compliance with the Affiliate Code of Conduct and the pricing protocol approved by the Board. All transactions were executed by ERM employees and were subject to the oversight of existing NSPI management, as promised by NSPI in its NSPEMI application to the Board.

Conclusion XII-32: The output and cost of the Brooklyn Energy facility grew considerably from the prior audit period (█ GWh for just under \$█ million). The primary reason for this large increase in output was simply a return to consistent normal production following a lengthy outage in the prior audit period. NSPI’s compliance with a legislative requirement to pay \$30/MWh in additional cost (in 2024 and through the end of February 2025) also increased cost. Further, as of March 1, 2025, NSPI is required to pay an amount to Brooklyn that was established by the Board under subclause 18(2)(a)(ii) of the Renewable Energy Standard on all dispatchable renewable electricity acquired from a biomass facility. The regulation specified that this new rate established by the Board “overrides any other payment amount specified in any existing power purchase agreement.” The rate paid by NSPI to Brooklyn was \$█/MWh. Over the ten months in which this new regime was in place, NSPI received █ MWh of energy from Brooklyn at a total cost of \$█. We continue to find the Brooklyn facility to be an expensive source of energy, now made more expensive by the new rate charged to NSPI since March 1, 2025.

Conclusion XII-33: NSPI has adequately addressed all of our previous audit report’s recommendations on the topic of Power Purchases and Sales.

XII.D. Recommendations

Recommendation XII-1: By the earlier of the resolution of the dispute or the end of 2026, NSPI should update the Board regarding its efforts to recover the value associated with [REDACTED]
[REDACTED]

Recommendation XII-2: NSPI should report in its FAM Annual Report NLH's average Surplus Energy offered to date, as of the end of the most recent EAA contract year.

XIII. Hedging

XIII.A. Background

To fuel its generating units, NSPI must buy fuel on the open market, which exposes NSPI—and FAM customers—to price risk. If fuel prices rise, NSPI must pay more (and charge FAM customers more) for fuel; if fuel prices fall, NSPI and FAM customers pay less. Volatility in fuel prices can lead to volatility in FAM customer rates. Hedging is a process that reduces FAM customers' exposure to changing fuel prices and thus can moderate rate volatility. Fixed-price physical or financial contracts fix the price of fuel regardless of whether market prices rise or fall. Hedging is not seeking to reduce cost; rather, it is seeking to lower risk.

Until the end of 2016, NSPI's approach to hedging varied by fuel,⁷³⁷ and NSPI's hedging activities and the prudence of those activities was reviewed as part of the FAM audit process.⁷³⁸ Beginning in 2017, NSPI's approach to hedging changed. The impetus for this change was Nova Scotia legislature's Electricity Plan Implementation Act ("EPIA").⁷³⁹ The EPIA required NSPI to submit a Fuel Stability Plan that was designed to stabilize rates throughout the three-year Rate Stability Period ("RSP") to the Board for approval. This plan was required to include "a description of any hedging strategies or mechanisms proposed to be used by Nova Scotia Power to manage fuel costs during the Rate Stability Period."⁷⁴⁰ In other words, as noted by the Board in the Rate Stability Order, "the EPIA requires the Board to give advance approval of the hedging strategy, thus reducing any risk to NSPI shareholders that there may be a finding of imprudence."⁷⁴¹

In 2019, the final year of the 2017-2019 Rate Stability Period, NSPI submitted an application to the Board for approval of another three-year "Fuel Stability Period," which would set BCF rates for 2020-2022 and incorporate AA and BA riders from the prior period.⁷⁴² The Board approved the application,⁷⁴³ which included a hedging plan that was similar to the hedging plan used in the 2017-2019 Rate Stability Period.⁷⁴⁴

⁷³⁷ NSPI, "Fuel Hedging Plan," Version 1.4, September 2016, Appendix A.

⁷³⁸ NSUARB, "Decision," 2016 NSUARB 129 M07348 ("Rate Stability Decision"), paragraph 52.

⁷³⁹ Nova Scotia Legislature, "Electricity Plan Implementation (2015) Act," December 18, 2015, available at https://nsllegislature.ca/legc/bills/62nd_2nd/3rd_read/b141.htm.

⁷⁴⁰ EPIA, 4(d).

⁷⁴¹ Rate Stability Decision, paragraph 53.

⁷⁴² NSUARB, "Decision," 2019 NSUARB 165 M09288 ("Fuel Stability Decision"), paragraphs 1 to 2.

⁷⁴³ Fuel Stability Decision, paragraph 2.

⁷⁴⁴ Nova Scotia Power, Inc., "2020-2022 Fuel Stability Plan Application," June 27, 2019, M09288, section 12. The hedging plan was included in the application as Appendix A OE-01J Attachment 1.

NSPI updated its hedging plan in 2022 as part of its general rate application.⁷⁴⁵ The updated hedging plan addressed a new “Fuel Stability Period” of 2022 through 2024.⁷⁴⁶ In 2023 and 2024, NSPI developed further edits to its Fuel Manual, including its hedging plan. Those edits were finalized into Version 14 of the Fuel Manual, effective May 2024, including version 2.4 of the hedging plan. This version of the hedging plan was in effect during the rest of the Audit Period and is what we will refer to as the “Fuel Hedging Plan.” The primary purpose of this update was to revise the discussion of greenhouse gas impacts on hedge rebalancing in light of the implementation of Nova Scotia’s Output-Based Pricing System (“OBPS”). Nevertheless, the Fuel Hedging Plan changed little during the Audit Period (or from the prior audit period), and thus we refer to the “Fuel Hedging Plan” in our findings in the remainder of this chapter.

Our purpose in this chapter is to explain how NSPI approached hedging during the Audit Period and to assess the results. Before we turn to our findings, conclusions, and recommendations, we begin with a primer on NSPI’s approach to hedging during the Audit Period.

XIII.A.1. Summary of NSPI’s Hedging Program during the Audit Period

NSPI’s Fuel Hedging Plan is contained in the Fuel Manual.⁷⁴⁷ Since NSPI was not in a rate/fuel stability plan during the Audit Period, the Fuel Manual called for NSPI to hedge a target amount of [REDACTED] of the total forecast of NSPI’s fuel consumption for the current year, [REDACTED] for Year + 1, [REDACTED] for Year + 2, and [REDACTED] for Year + 3.⁷⁴⁸ This target percentage range is subject to available liquidity in suitable hedging products.

For individual fuels, NSPI’s approach during the Audit Period was to hedge between [REDACTED] % of its exposure.⁷⁴⁹ The Fuel Hedging Plan also calls for “quarterly rebalancing” of NSPI’s hedged position.⁷⁵⁰ Below, we highlight material features of NSPI’s approach to fuel hedging during the Audit Period.

XIII.A.1.a.i. Permitted Financial Products and Trade Types

Subject to approval of the Fuel Strategy Table, the general types of financial contracts permitted by the Fuel Hedging Plan are presented in Figure XIII-1 below, which also explains the characteristics of each financial instrument.

⁷⁴⁵ NSPI, “2022-2024 General Rate Application,” M10431, January 27, 2022, as updated February 18, 2022, Appendix 4B.

⁷⁴⁶ 2022-2023 Bates White Audit Report, pgs. 370-371.

⁷⁴⁷ NS Power Fuel Hedging Plan, Version 2.4, May 2024, Fuel Manual Revision 14, Link 12.

⁷⁴⁸ Fuel Hedging Plan, page 9.

⁷⁴⁹ Fuel Hedging Plan, page 9.

⁷⁵⁰ Fuel Hedging Plan, page 8.

Figure XIII-1: Permitted Financial Contract Types⁷⁵¹

Financial Hedge Instrument	Definition	Trading	NSPI Permitted Settlement
Futures	A futures contract <i>obligates</i> the buyer (seller) to purchase (sell) an asset at a particular time in the future at a particular price.	Standardized contract – trades on an exchange	Cash
Forwards	A customized contract obligating the buyer (seller) to purchase (sell) an asset at a particular time in the future at a particular price.	Non-standard contract – Over-the-Counter (“OTC”), non-exchange traded	Cash or Physical Delivery
Swaps ⁷⁵²	A derivative contract where the two sides of the deal agree to exchange cash flows, which are derived from the price of an underlying commodity.	OTC	Cash
Options ⁷⁵³	An option provides the buyer with the right but NOT the obligation to buy (call) or sell (put) an asset at an agreed upon price (strike price) during a certain period of time or on a particular date (exercise date).	Traded on an exchange with standard settlement dates.	Cash
			Physical optionality possible
Structured Products	Unique products designed to meet a particular hedging requirement. Typically higher cost/lower liquidity than standard products.	Typical counterparty is an investment bank.	Specific to product

In some instances, NSPI may use alternative, highly correlated financial products to hedge a specific risk because either an effective hedging instrument does not exist or existing products are not sufficiently liquid.⁷⁵⁴ The correlated product may be a contract on the same underlying commodity but differ in terms of delivery date, product quality, or delivery point; it may be a contract on a different commodity that has highly correlated price movements with the product to be hedged. The effectiveness of these types of

⁷⁵¹ Fuel Hedging Plan, pages 5 to 7.

⁷⁵² One side of the commodity swap, the floating leg, is tied to the price of a commodity or a commodity index, while the payments on the other side, the fixed leg, are stipulated in the contract. It is common for a commodity swap to be settled in cash, although physical delivery is possible. The floating leg is typically held by a commodity consumer that is willing to pay a fixed rate for a commodity to guarantee its price. The fixed leg is typically held by a commodity producer that agrees to pay a floating rate, which is set by the market price of the underlying commodity, thereby hedging against falls in the price of the commodity. In most cases, swap rates are fixed either by commodity futures or by estimating the commodity forward price.

⁷⁵³ Permissible contract types include swing options. A swing options contract states the least and most energy an option holder can buy (or “take”) per day and per month, how much that energy will cost (its strike price) and how many times during the month the option holder can change (or “swing”) the daily quantity of energy purchased.

⁷⁵⁴ Fuel Hedging Plan, page 11.

hedges is measured through analysis of the relationship between the price movements in the underlying exposure and those of the hedging product.⁷⁵⁵

Appendix B of the Fuel Hedging Plan lists the hedging products NSPI anticipated using during the Audit Period for each fuel. These are shown in Figure XIII-2 below. The use of any other products requires pre-approval from the Fuel Strategy Table.⁷⁵⁶

Figure XIII-2: Approved Hedging Products per the Fuel Hedging Plan⁷⁵⁷

Fuel	Primary Financial Hedging Index	Secondary Financial Hedging Index(es)	Physical Hedging Opportunities
Coal			
HFO			
Natural Gas			
Power			

XIII.A.1.a.ii. Counterparties

NSPI is permitted to use both bilateral, over-the-counter (“OTC”) transactions and exchange-cleared transactions (e.g., NYMEX) in hedging.⁷⁵⁸ One main difference between OTC and exchange trades is counterparty risk; OTC transactions are riskier because NSPI is exposed to the credit risk of the counterparty, whereas exchanges require transacting parties to post credit security in order to transact. Conversely, exchange transactions have higher up-front cash flow requirements than bilateral trades due to margin requirements at the exchanges. Bilateral transactions may be entered into with either financial or non-financial parties.⁷⁵⁹ For OTC trades, which again are riskier than exchange trades, the Fuel Hedging Plan recommends that master trading agreements be used whenever possible—this helps mitigate risk and impose standardized terms and conditions on NSPI’s OTC hedging transactions.⁷⁶⁰

⁷⁵⁵ Fuel Hedging Plan, page 11.

⁷⁵⁶ Fuel Hedging Plan, page 5.

⁷⁵⁷ Fuel Hedging Plan, Appendix B.

⁷⁵⁸ Fuel Hedging Plan, pages 12-13.

⁷⁵⁹ Fuel Hedging Plan, pages 12-13.

⁷⁶⁰ Fuel Hedging Plan, page 12. NSPI procures its financial hedging products through a number of OTC and exchange traded (centrally cleared) contracts. The OTC contracts were executed pursuant to ISDA master trading agreements. The cleared contracts are primarily executed through the Intercontinental Exchange’s WebICE trading platform. Brokers are occasionally used for trading in illiquid markets.

XIII.A.1.a.iii. Strategy and Rebalancing

NSPI seeks to [REDACTED]. Hedged volumes will incur a loss (gain) as prices fall (rise). Unhedged volumes can take advantage of the lower market prices but are exposed to increases in prices. The Fuel Hedging Plan also requires NSPI to rebalance hedges on a quarterly basis, subject to the availability of suitable hedging products.

Rebalancing the hedging portfolio, unwinding existing hedges, or executing new hedges is based on the results of the quarterly updates to the fuel consumption forecasts, available liquidity in the relevant hedging products, and recognition of any resulting gains or losses.⁷⁶¹ Volumetric requirements for each fuel are derived from the Plexos model, which is to be updated no less than quarterly during each year.⁷⁶² For example, at the beginning of a quarter, NSPI may show that it is 80% hedged for its expected coal needs for the following year; however, if during the quarter the price of coal falls substantially relative to other fuels, it may be that the next quarterly Plexos forecast shows a significant increase in expected coal consumption over the next year. Thus, NSPI would no longer be 80% hedged, and it would seek to procure additional hedges as part of the rebalancing process, subject to the available liquidity in a relevant coal hedging product.

XIII.A.1.a.iv. Unhedgeable Risks

NSPI notes in its Fuel Hedging Plan that there is [REDACTED]
[REDACTED]⁷⁶³ NSPI identifies four specific risks for which a direct economic hedge either is not available or would be of prohibitive cost:⁷⁶⁴

[REDACTED]

XIII.A.1.a.v. Procedure and Oversight

Planning, executing, monitoring, and reporting of hedges requires coordination across NSPI. The FST governs fuel procurement and hedging subject to both the Risk Management Policy and the Credit Policy.⁷⁶⁵ The Portfolio Optimization Group is responsible for running the Plexos models to produce the fuel forecasts.⁷⁶⁶ The Fuel Finance team translates the Plexos model output into a forecast of expected

⁷⁶¹ Fuel Hedging Plan, pages 9-10.

⁷⁶² Fuel Hedging Plan, page 9.

⁷⁶³ Fuel Hedging Plan, page 13.

⁷⁶⁴ Fuel Hedging Plan, pages 15-16.

⁷⁶⁵ Fuel Hedging Plan, page 19.

⁷⁶⁶ Fuel Hedging Plan, page 19.

cost for fuel and purchased power.⁷⁶⁷ The ERM team is responsible for executing fuel procurement transactions, including hedging.⁷⁶⁸ Once the FST has approved a particular strategy and/or trade, the primary responsibility for the hedge execution belongs to the Manager of Gas & Oil, with other positions providing support.⁷⁶⁹

NSPI's Fuel Procurement Risk Management Policy and Procedures manuals state that hedge effectiveness testing reports are to be produced on a quarterly basis. These reports are distributed to the CROC. Hedge compliance reports are to be produced on a quarterly basis and are distributed to the Fuel Strategy Table.⁷⁷⁰

Exposure to the credit risk of the counterparty in bilateral transactions is monitored by ERM and reported to ERM and management. The FST, ERM, or CROC is responsible for action in response to these reports when called for by NSPI's credit policies.⁷⁷¹

XIII.B. Findings

XIII.B.1. Assessment of NSPI's Hedging Program Results

We assessed the effectiveness of NSPI's hedging activities during the Audit Period by first considering whether NSPI's hedging is meeting the goal of greater stability in electricity rates, a target that is laid out in the first paragraph of NSPI's Fuel Hedging Plan.⁷⁷²

Our assessment then looks at the impact of NSPI's hedging on the stability of rates. We examine the consistency of NSPI's hedging activities with the objectives and requirements as set forth in NSPI's governing documents. Next, we provide an assessment of the effectiveness of NSPI's hedging activities at the portfolio level. We do this by considering portfolio-level regression analysis, estimates of portfolio VaR, and a review of hedging program costs (e.g., transaction fees). We then look at NSPI's hedging activities for success at the individual fuel level by considering estimates of hedging transactions' impact on VaR by fuel; we also review NSPI's procurement processes for acquiring hedges. In addition, we assess the relationship between the hedged product and the fuel being hedged through the application of regression analysis to individual trades.

⁷⁶⁷ Fuel Hedging Plan, page 19.

⁷⁶⁸ Fuel Hedging Plan, page 19.

⁷⁶⁹ Fuel Hedging Plan, page 19.

⁷⁷⁰ NSPI, Fuel Procurement Risk Management Policy & Procedures, November 22, 2023 (Fuel Manual Revision 14, Link 3), Appendix C.

⁷⁷¹ Fuel Hedging Plan, pages 12-13.

⁷⁷² Fuel Hedging Plan, page 3.

XIII.B.1.a. Consistency with Fuel Stability Objectives

While the Fuel Stability/Rate Stability Period was not in place during the Audit Period, we still begin with a review of the FAM results for the objective of stabilizing fuel costs. During the Audit Period, NSPI over-recovered FAM costs, though actual FAM costs exceeded the recovered FAM cost (via the base cost of fuel rate, before interest) in 20 out of 24 months.⁷⁷³ Recovered costs exceeded actual FAM costs in 2024 by approximately \$451.7 million (including interest),⁷⁷⁴ though this over-recovery was caused by the proceeds of a \$485.9 million reduction in fuel costs as a result of the Federal Loan Guarantee received by NSPI on behalf of FAM customers in December 2024.⁷⁷⁵ In 2025, actual FAM costs exceeded recovered cost by \$157.9 million (including interest)⁷⁷⁶ for a total end-of-Audit-Period balance of \$101.6 million (including interest).⁷⁷⁷

It is difficult to derive the precise impact of NSPI's hedging activities on these results. Many factors can drive differences between the fixed FAM rate and the actual FAM costs, such as market fuel prices that are significantly different than forecast. Also, to the extent that energy demand exceeds forecast on which NSPI's hedging targets are based, NSPI will be exposed to short-term market price fluctuations in procuring additional fuel and purchased power to meet that demand. Changes in legal and regulatory policy can also have an impact, such as the SO₂ CoV received in March 2025, which materially changed NSPI's optimal fuel mix. We further assess the effectiveness of NSPI's hedging activities by reviewing several other metrics below.

XIII.B.1.b. Consistency with Hedging Plan Requirements

The next way we assessed NSPI's hedging activities during the Audit Period was to review NSPI's compliance with the plain language of the Fuel Hedging Plan regarding hedging targets. As noted above, under the Fuel Hedging Plan, NSPI sought to hedge [REDACTED] of its forecasted fuel consumption and [REDACTED] of each fuel type during the current year and declining percentages in following years, "[REDACTED]".⁷⁷⁸ Figure XIII-3 below clarifies NSPI's hedge targets during the Audit Period as noted in the Fuel Manual.

⁷⁷³ NSPI December 2024 FAM Monthly Report FAM Calculation Model, tab "Schedule 1 – FAM Calculation;" NSPI December 2025 FAM Monthly Report FAM Calculation Model, tab "Schedule 1 – FAM Calculation."

⁷⁷⁴ NSPI December 2024 FAM Monthly Report FAM Calculation Model, tab "Schedule 1 – FAM Calculation."

⁷⁷⁵ NSPI Fuel Adjustment Mechanism Monthly Report – December 2024, Transmittal Letter, page 3.

⁷⁷⁶ NSPI December 2025 FAM Monthly Report FAM Calculation Model, tab "Schedule 1 – FAM Calculation."

⁷⁷⁷ NSPI December 2025 FAM Monthly Report FAM Calculation Model, tab "Schedule 1 – FAM Calculation."

⁷⁷⁸ Fuel Hedging Plan, page 8.

Figure XIII-3: NSPI's Target Hedge Percentages⁷⁷⁹



Our review of NSPI's data suggests that NSPI met the targets of its Fuel Hedging Plan for most fuels. Entering the Audit Period, NSPI had hedged between [REDACTED] of its exposure to all fuels except natural gas at basis price risk (though only slightly at [REDACTED]%) in 2024 and all fuels (except solid fuel, at [REDACTED]%, and fuel oil, at [REDACTED]%) in 2025. By the end of 2024, NSPI had again hedged between [REDACTED] of all fuels except natural gas at basis price risk for 2025, but was below target on all fuels except for fuel oil in 2026. By the end of the Audit Period, NSPI reached the [REDACTED] target in all fuels for 2026 (including both natural gas at Henry Hub and natural gas at basis price risk). Figure XIII-4 shows NSPI's hedge positions in three different time periods: end of first quarter, 2024; end of fourth quarter, 2024, and end of fourth quarter, 2025.

⁷⁷⁹ Fuel Hedging Plan, page 9.

Figure XIII-4: Compliance with Hedging Targets in the Fuel Hedging Plan⁷⁸⁰

	Solid Fuel	Solid Fuel Transport (Ocean)	Natural Gas	Power	Fuel Oil
2024 Q1					
2024					
2025					
2026					
2027					
2024 Q4					
2025					
2026					
2027					
2028					
2025 Q4					
2026					
2027					
2028					

NSPI acknowledged that it was, at times, outside the target hedge percentage for certain fuels for limited periods. A primary reason NSPI cited for this was limited liquidity, particularly with relation to natural gas at basis price risk.⁷⁸¹ Additionally, following from the receipt of the SO₂ CoV in March 2025 was an over-hedged position in natural gas and power imports and an open position in the solid fuel portfolio, both of which were soon after rebalanced accordingly.⁷⁸² NSPI also directly hedges exposure to forecasted EAA Surplus Energy, which is priced at the ISO New England Mass Hub day-ahead price.⁷⁸³ Thus, as expectations of the timing and EAA Surplus Energy deliveries change, NSPI may add or unwind hedge contracts that settle on the Mass Hub price. As for NS Block (and make-up NS Block) volumes, these all have a price of zero and do not require hedging.⁷⁸⁴ However, when the timing and volumes of the NS Block deliveries differ materially from forecast (as they did entering the Audit Period), NSPI may need to add new or unwind existing hedges.

⁷⁸⁰ NSPI FAM Quarterly Reports, 2024 Q1, 2024 Q4 and 2025 Q4, Sheet Q1. Solid Fuel Transport shows the data for Ocean Freight.

⁷⁸¹ Quarterly Hedging Plan Compliance Reports.

⁷⁸² Quarterly Hedging Plan Compliance Reports.

⁷⁸³ 2022-2023 Bates White Audit Report, page 378.

⁷⁸⁴ 2022-2023 Bates White Audit Report, page 378.

NSPI's hedging decisions and their success in shielding FAM ratepayers from volatile fuel costs are dependent upon the accuracy of NSPI's fuel consumption forecasts. Assume, for example, NSPI forecasts consumption of 100,000 MMBtu of natural gas in a given period, and, consistent with the Fuel Hedging Plan, hedges 100% of that exposure (both Henry Hub and basis). If, in reality, NSPI burns 200,000 MMBtu—twice what was forecasted—then NSPI has exposure to 100,000 MMBtu of natural gas supply, and in fact was only 50% hedged. To help mitigate the impact of forecast error, the Fuel Hedging Plan contains parameters for both regular and interim rebalancing. We address this next.

XIII.B.1.c. Compliance with Quarterly Rebalancing Provisions of Fuel Hedging Plan

The Fuel Hedging Plan calls on NSPI to actively update and manage its hedge portfolio throughout the hedging plan. Specifically, the Fuel Hedging Plan states:

[REDACTED]

We reviewed NSPI's rebalancing activities during the Audit Period to determine if (1) NSPI was conducting quarterly rebalancing and (2) how NSPI's quarterly rebalancing activities translated into additional hedging activity. Our review showed that NSPI conducted quarterly rebalancing in all eight quarters during the Audit Period, using updated fuel consumption forecasts from Plexos to determine whether NSPI would need to enter into additional hedges or unwind existing hedges to remain in compliance with Fuel Manual targets. NSPI also conducted an interim rebalance during Q1 2025 related to changes in expectations of its fuel mix following receipt of the SO₂ CoV. (NSPI conducted a tenth forecast—an interim forecast in Q3 2024—but did not specifically rebalance its portfolio in response to this forecast.) Following the update to the fuel consumption forecasts, the Manager of Portfolio Optimization presented recommendations to the FST seeking approval to execute certain trades/purchases to rebalance the portfolio.

We logged notable items from our review of the ROAs associated with NSPI's quarterly rebalancing. Before we provide the details of those ROAs and decisions, we begin with what was a major theme of the prior audit period—specifically, the impact of changes in the timing and volume of energy flows from NLH on the Maritime Link on NSPI's hedging activities. **Figure XIII-5** below shows the total energy forecasted to flow to Nova Scotia from NLH over the Maritime Link, by year (2024 through 2028), across

⁷⁸⁵ Fuel Hedging Plan, page 9.

all ten forecasts relevant to the Audit Period. Italics indicate that the forecast did not cover all months of the year; for example, the Q1 2024 forecast covered the months February through December 2024 (and thus is italicized), but all months for 2025 and 2026 (and thus, not italicized).

Figure XIII-5: Annual Forecast Volumes of all Maritime Link Energy (2024-2028), by Audit Period Forecast (GWh)

Year	Q1 2024	Q2 2024	Q3 2024	Q3 2024 (Interim)	Q4 2024	Q1 2025	Q1 2025 (Interim)	Q2 2025	Q3 2025	Q4 2025
2024	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2025	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2026	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2027	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2028	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████

The figure above shows that overall expectations of Maritime Link energy fell modestly during the Audit Period, but far less than the declines observed in the prior audit period. For example, in its Q1 2024 forecast, NSPI forecasted █████ GWh of total Maritime Link imports in 2026; by the final forecast of the Audit Period (Q4 2025), NSPI expected █████ GWh in 2026, █████ of █████%. Expectations for 2027 imports from Newfoundland similarly declined from an initial estimate of █████ GWh (in the Q3 2024 forecast) to █████ GWh (in the Q4 2025 forecast), █████ of █████%.

Given that “Muskrat Falls” or “Maritime Link” energy are broad terms encompassing several potential products, we reviewed this data on a more granular level. We noted that forecasts of Base Block remained steady across the forecasts, staying at approximately 894 GWh/year in all forecasts. Forecasts for Supplemental Block, in contrast, was subject to an error during the Audit Period. In all forecasts between Q1 2024 and Q1 2025, inclusive, NSPI forecasted the contracted volume for Supplemental Energy of 240 GWh/year through 2026, and then a final, partial year delivery of 143 GWh in 2027. However, the fifth and final year of Supplemental Block deliveries under the Energy and Capacity Agreement is 2026, not 2027. NSPI corrected its mistake in the Q2 2025 forecast, forecasting 143 GWh in 2026 and no additional Supplemental Block thereafter. (This reduction helps explain some of the overall decrease in Maritime Link Energy in 2026 and 2027.) Despite the error, we identified no evidence suggesting that the incorrect forecasted Supplemental Block volumes had any material impacts on NSPI’s hedging decisions.

The largest driver of the data and phenomenon shown in Figure XIII-5 above is the changes that were made to the timing and expected volumes of EAA Surplus Energy. This is shown in Figure XIII-6 below.

Figure XIII-6: Annual Forecast Volumes of EAA Surplus Energy (2024-2028), by Audit Period Forecast (GWh)

Year	Q1 2024 Volume (MWh)	Q2 2024 Volume (MWh)	Q3 2024 Volume (MWh)	Q3 2024 (Interim) Volume (MWh)	Q4 2024 Volume (MWh)	Q1 2025 Volume (MWh)	Q1 2025 (Interim) Volume (MWh)	Q2 2025 Volume (MWh)	Q3 2025 Volume (MWh)	Q4 2025 Volume (MWh)
2024	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2025	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2026	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2027	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████
2028	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████	██████████

Figure XIII-6 shows that forecasted Surplus Energy decreased during the Audit Period, particularly for 2026. In its Q1 2024 forecast, NSPI forecasted █████ GWh of Surplus Energy imports in 2026; by the final forecast of the Audit Period (Q4 2025), NSPI expected █████ GWh in 2026, a decrease of █████%. Expectations for 2027 Surplus Energy also █████ albeit by a lesser degree, from an initial estimate of █████ GWh (in the Q3 2024 forecast) to █████ GWh (in the Q4 2025 forecast), █████ of █████%. As we discuss further below, beginning in Q3 2025, NSPI began taking a more conservative approach for estimating Surplus Energy, which resulted in █████ in expected Surplus Energy; for example, expected Surplus Energy in 2025 █████ GWh.

The impact of these adjustments on hedging activities can be significant. To the extent NSPI receives less actual Maritime Link energy in a period than was expected (and on which NSPI's hedging decisions were based), NSPI has to make up for those missing MWhs from other sources, including consumption of additional fuel at its power plants or through other imported energy, and in doing so, NSPI is exposed to market prices for fuel and purchased power. █████

████████████████████. Whether these changes lead to incremental fuel costs or incremental fuel savings depends on how the market moved between the time the hedge was purchased and the time it was unwound. We provide some details observed from selected quarters in the Audit Period in the discussion below.

XIII.B.1.c.i. 2024 (First Quarter)

NSPI completed its quarterly rebalance for the first quarter of 2024 in March. NSPI's forecast of EAA Surplus Energy was limited to approximately █████ GWh in 2024, and between █████ and █████ TWh in 2025 and 2026. NSPI explained that its decision was based on experience to date. NSPI noted uncertainty related to outstanding full rating tests (900 MW) and software updates of the LIL among other reasons for the reduction in forecasted EAA Surplus Energy. NSPI stated its intention to continually assess EAA opportunities following the completion of the March full rating tests.

NSPI purchased █████ GWh of Mass Hub power hedges to initiate hedging for 2026, bringing its hedged percentage on █████ exposure to █████ percent for that year. NSPI also applied an updated load forecast that decreased forecasted load by █████ GWh for the February 2024 through 2026 time horizon.

NSPI procured [REDACTED]
[REDACTED]
[REDACTED]. Additionally, NSPI hedged [REDACTED] barrels of HFO
([REDACTED] based on an expected crude delivery in Q4 2024. NSPI noted that economic switching
between gas and HFO had caused consumption to [REDACTED] compared to the fourth quarter of 2023.

We note here that in this first quarter 2024 rebalance forecast, NSPI assumed that PHP would become a FAM customer (with an embedded rate) starting in 2026. Accordingly, NSPI's PLEXOS forecast that was used to determine hedging decisions included PHP load starting in 2026. This is a departure from prior periods, when PHP was modeled as a below-the-line customer on its own tariff, and thus was not included in hedging decisions, per the Fuel Hedging Plan. In its ROA, NSPI asserted that the inclusion of PHP's load in 2026 had no impact on hedge recommendations since the volume of 2026 hedges was [REDACTED]. This appears to be true. The hedges NSPI added in the first quarter of 2024 still left significant individual fuel exposure in 2026; following the rebalancing, NSPI would be just [REDACTED]% hedged for solid fuel, [REDACTED]% for power imports, [REDACTED]% for natural gas ([REDACTED]), and [REDACTED]% hedged for [REDACTED] basis. Still, it should be noted that with PHP's load included in 2026, NSPI's forecasted imports from [REDACTED] [REDACTED] GWh and its expected fuel consumption (in MMBtu) increased by [REDACTED]% for natural gas, [REDACTED]% for HFO, and [REDACTED]% for diesel.

XIII.B.1.c.ii. 2024 (Second Quarter)

In the second quarter of 2024, NSPI engaged in moderate rebalancing for purchased power, solid fuel, and natural gas. NSPI purchased an additional [REDACTED] GWh of [REDACTED] power hedges for 2026, initiating hedging for off peak exposure and bringing its hedged percentage on [REDACTED] exposure to [REDACTED] percent for the year. NSPI procured [REDACTED] GBtu of both [REDACTED] and [REDACTED] basis hedges to reduce exposure during winter 2024/2025, and smaller amounts of [REDACTED] contracts to [REDACTED] its exposure to solid fuel prices and bring the portfolio closer to target ranges.

During the quarter, NSPI also received FST approval to use all of its GHG OBPS Performance Credits generated in 2023 to offset 2023 OBPS obligations. (PHB generated OBPS performance credits during the Audit Period, as did Lingan and Trenton in 2025 only.) NSPI assessed the value of this option against banking the OBPS credits and applying them equally in all years from 2023 to 2030, which is the maximum number of years (seven) that OBPS credits may be applied under the program. The latter option had a net present value that was \$[REDACTED] million [REDACTED] the decision to apply all the OBPS credits in 2023. However, NSPI decided to apply all OBPS credits in 2023 to maximize the immediate decrease on the FAM balance and to account for risks associated with changes to the OBPS program and the assumed resource portfolio. We confirmed with NSPI that although it provides GHG OBPS updates to the FAM Small Working Group in its quarterly meetings, NSPI has never received feedback from stakeholders regarding a strategy for using OBPS credits. We do not include a recommendation here, as we expect NSPI would continue to provide OBPS credit updates and allow for discussion in the FAM Small Working Group meetings.

This quarter's rebalancing again included PHP load in 2026. In its ROA, NSPI again claimed that the inclusion of PHP's load in 2026 had no impact on hedge recommendations since the volume of 2026 hedges was [REDACTED]. This again appeared true. The hedges NSPI added in the second quarter of 2024 still left [REDACTED] in 2026; following the rebalancing, NSPI would be just [REDACTED]% hedged for solid fuel, [REDACTED]% for power imports, [REDACTED]% for natural gas ([REDACTED]), and [REDACTED]% hedged for [REDACTED] basis.

XIII.B.1.c.iii. 2024 (Third Quarter)

Entering the Audit Period, NSPI was in the midst of a two-year sulfur emissions compliance period, which limited NSPI's total SO₂ emissions to 31.6 kt in 2024. In November 2023, NSPI implemented a compliance "buffer" of 3 kt of SO₂ emissions for 2023 and 2024 to better prevent against non-compliance. Compliance with this limit in 2024 was challenging, as NSPI tested and used considerably lower sulfur blends in its solid fuel plants to help meet compliance.

In the third quarter of 2024, NSPI conducted an analysis to determine whether to continue use of a sulfur emissions compliance buffer in 2025 and 2026. NSPI's analysis noted that its most recent load forecast (received in the third quarter) showed a significant increase in 2025 forecasted load (+ 48GWh), while its expected Surplus Energy forecast was cut by [REDACTED] GWh in 2025 and [REDACTED] GWh in 2026. Moreover, the SO₂ annual emissions limits also decrease materially, to 28 kt in 2025 and 23 kt in 2026. In light of these facts and the risks of changes in load and generation from forecast, NSPI determined to apply a buffer and to increase that buffer to 6 kt. This volume was driven by the collective standard deviation of output from the generation and load resources it relies upon for power. NSPI estimated the incremental cost of this compliance buffer to be \$[REDACTED] million in 2025.

NSPI also engaged in material rebalancing in the third quarter of 2024. Updates to two key factors drove the need for portfolio rebalancing. First, NSPI's load forecast update showed an increase in 2025 load of 48 GWh and 100 GWh of increased load over the 2024-2026 period. Second, in light of continued uncertainty regarding LIL maintenance and future deliveries, NSPI reduced its forecast of Surplus Energy to [REDACTED] GWh in 2025 and [REDACTED] GWh in 2026, both down from [REDACTED] GWh. NSPI explained that it made these changes during an ongoing maintenance outage on the LIL after it learned of the expected duration of the outage. The outage was taken to install new software and to complete annual planned maintenance activities.

As a result of these changes, NSPI unwound [REDACTED] GWh of [REDACTED] power hedges for the period of October 2024 through November 2024, crystallizing a mark-to-market loss of approximately USD \$[REDACTED] million. NSPI purchased an additional [REDACTED] GWh of [REDACTED] power hedges for 2026, bringing its hedged percentage on [REDACTED] exposure to [REDACTED] percent for the year and closer to the [REDACTED] percent target. NSPI procured significant amounts of [REDACTED] [REDACTED] ([REDACTED] GBtu), [REDACTED] basis ([REDACTED] GBtu), and [REDACTED] basis ([REDACTED] GBtu) hedges, both to further reduce exposure during the winter 2025 gas procurement season and to bring the portfolio in line with 2026 targets. NSPI also continued to layer on more [REDACTED] to

address increased consumption driven by the usage of cleaner solid fuel blends to accommodate SO₂ requirements.

Starting in the third quarter of 2024 and continuing through the end of the Audit Period, NSPI no longer included 2026 PHP load in its hedging forecast. At that point, NSPI updated its assumptions to no longer expect PHP to be on an embedded rate in 2026. Despite this updated assumption, which reduced expected demand to be hedged in 2026, there were [REDACTED] as a result of this decision, nor did we observe any unreasonable hedge positions for 2026 in the third quarter of 2024.

XIII.B.1.c.iv. 2024 (Fourth Quarter)

Fourth quarter 2024 rebalancing focused most heavily on initiating natural gas hedging in 2027. NSPI procured large amounts of [REDACTED] ([REDACTED] GBtu), [REDACTED] basis ([REDACTED] GBtu), and [REDACTED] basis ([REDACTED] GBtu) hedges, both to begin filling out the open 2027 position as well as to further reduce exposure in 2025 and 2026. NSPI layered on more [REDACTED] hedges for 2026, bringing its hedged percentage on LS exposure to [REDACTED] percent for the year.

Due to further [REDACTED] revisions to the expected Surplus Energy volumes, NSPI unwound [REDACTED] GWh of [REDACTED] power hedges collectively in the months of December 2024 and March 2025, crystallizing a mark-to-market gain of approximately USD \$[REDACTED] million. (We reviewed and verified this gain.) NSPI also noted that the PLEXOS model was updated to more accurately model Maritime Link and New Brunswick imports in appropriate on and off-peak blocks. Specifically, [REDACTED]
[REDACTED]
[REDACTED]. NSPI purchased an additional [REDACTED] GWh of [REDACTED] power hedges for 2026, bringing its hedged percentage on [REDACTED] exposure to [REDACTED] percent for the year.

XIII.B.1.c.v. 2025 (First Quarter)

NSPI completed its quarterly rebalance for the first quarter of 2025 in March. NSPI noted no material changes to expectations regarding the timing of EAA Surplus Energy deliveries and made only modest rebalancing changes to its portfolio. NSPI unwound [REDACTED] GWh of on-peak [REDACTED] power hedges for May 2025, which at the time was [REDACTED] at [REDACTED]%. The unwound hedges crystallized a mark-to-market [REDACTED] of about USD \$[REDACTED] million. NSPI also hedged [REDACTED] barrels of HFO ([REDACTED] [REDACTED] [REDACTED]) [REDACTED] its hedged percentage on marine freight exposure from [REDACTED] to up to [REDACTED] percent for [REDACTED] and added additional [REDACTED] hedges for 2026, [REDACTED] its LSL position up to [REDACTED]% hedged.

Shortly after the Q1 2025 rebalancing, NSPI pursued an interim rebalance due to receipt of the CoV for SO₂ emissions at the end of March. The CoV allowed NSPI to emit up to 45 kt of SO₂ in 2025, up from 28 kt under the prior regime. The CoV also increased the annual emissions limit for both 2026 and 2027 to 45 kt and 40 kt, respectively, from 28 kt, but also required NSPI to average 26 kt per year over the 2026-2029 period. Overall, however, the CoV substantially loosened NSPI's short-term SO₂ constraints, which had the effect of making solid fuel consumption more economic over the period.

In terms of its impact on hedging, receipt of the CoV resulted in NSPI having an [REDACTED] position in natural gas and power imports and an open position in the solid fuel portfolio for the period. Specifically, NSPI's updated PLEXOS forecast showed [REDACTED] in expected expenditures on natural gas ([REDACTED]%), power imports ([REDACTED]%), and diesel ([REDACTED]%), while solid fuel expenditures were expected to [REDACTED]%. Overall, NSPI forecasted FAM cost savings of \$[REDACTED] million related to the CoV, which was calculated as the difference between the Q1 2025 PLEXOS forecast and the Interim Q1 2025 PLEXOS forecast (the latter of which considered the CoV).

To address the hedge imbalances caused by receipt of the CoV, NSPI unwound [REDACTED] hedges for April, May, and June of 2025 and unwound [REDACTED] hedges for May and June of 2025. These unwinds crystallized total mark-to-market [REDACTED] of approximately \$[REDACTED] million. NSPI also added [REDACTED] hedges for 2027 and closed out the marine freight position with [REDACTED] barrels of [REDACTED], superseding the original Q1 2025 recommendation of [REDACTED] barrels. NSPI noted that it did not pursue any additional solid fuel hedges for 2026 to maintain operational flexibility. NSPI's decision to conduct an interim rebalance was reasonable and represented proactive consideration of the impact of significant exogenous events on its exposure to fuel and purchased power prices.

XIII.B.1.c.vi. 2025 (Second Quarter)

In the second quarter of 2025, NSPI's updated PLEXOS forecast required moderate portfolio rebalancing. In its ROA, NSPI noted that the "with PHP" load forecast fell by [REDACTED] GWh for the period June 2025–December 2027. However, we confirmed that NSPI continues to [REDACTED] for the fuel and purchased power that is required to serve PHP, and thus this change in load [REDACTED] to any portfolio hedging changes. Another change in this forecast was the removal of the expectation that Trenton 5 would be placed in cold storage (and thus not available to PLEXOS to commit and dispatch) starting in May 2027. NSPI explained that the cold storage of Trenton 5 is contingent on the addition of new fast acting generation capacity, which is the responsibility of the IESO, and which was behind in NSPI's original schedule for reaching commercial operation.

NSPI added modest ([REDACTED] MWh) [REDACTED] hedges for August and October 2025 and [REDACTED] tonnes of [REDACTED] hedges in 2027. NSPI added [REDACTED] basis hedges for August through October 2025 ([REDACTED] GBtu) and a [REDACTED] new hedge in 2027 for the [REDACTED] basis ([REDACTED] GBtu). NSPI also [REDACTED] part of its [REDACTED] position for [REDACTED] in July–October of 2025 ([REDACTED] GBtu), crystallizing a loss of USD \$[REDACTED] million.

XIII.B.1.c.vii. 2025 (Third Quarter)

In the third quarter of 2025, NSPI's updated load forecast showed a substantial increase for the period September 2025 through the end of 2027, increasing by [REDACTED] GWh (inclusive of PHP demand). NSPI also noted that mercury became its largest binding emission constraint during the quarter, with the forecast expecting NSPI to emit the maximum allowed (45 kg) in 2025. Due to reductions in NLH's 24-month energy delivery forecast confirmed in Q2 2025, NSPI [REDACTED] GWh of [REDACTED] power hedges

collectively in the months of September and October 2025, crystallizing a mark-to-market [REDACTED] of approximately USD \$ [REDACTED] million. NSPI purchased [REDACTED] GWh of [REDACTED] power hedges to initiate hedging for 2027, bringing its hedged percentage on [REDACTED] exposure to [REDACTED] percent for the year.

NSPI procured [REDACTED] volumes of [REDACTED] ([REDACTED] GBtu) hedges, mostly to begin filling out the 2027 position, as well as [REDACTED] amounts of [REDACTED] hedges to close out the October 2025 position. NSPI's 2025 LSL position was [REDACTED] cargoes [REDACTED], NSPI [REDACTED] [REDACTED] tons of [REDACTED] hedges in Q4 2025 and purchased [REDACTED] tons of [REDACTED] hedges in Q1 2026; NSPI also initiated [REDACTED] hedges for 2027, bringing its hedged percentage on LSL exposure up to [REDACTED] percent for the year. Based on expected marine freight requirements for 2026 amounting to [REDACTED] barrels of [REDACTED] NSPI additionally hedged [REDACTED] barrels of HFO ([REDACTED])

XIII.B.1.c.viii. 2025 (Fourth Quarter)

In the fourth quarter of 2025, NSPI made a substantial change to its forecasted Surplus Energy in 2026, [REDACTED] it by [REDACTED] GWh, or [REDACTED]%. Because entering the quarter NSPI was only [REDACTED]% hedged for its [REDACTED] exposure in 2026, this revision [REDACTED] of existing hedges. Instead, NSPI pursued [REDACTED] volume hedges in 2026 for on-peak [REDACTED] exposure ([REDACTED] GWh January, [REDACTED] GWh October-November) and off-peak exposure ([REDACTED] GWh April-June, [REDACTED] GWh August-December), while maintaining [REDACTED] positions for February (on-peak) and July (on-peak) to allow for reassessment. NSPI also added [REDACTED] hedges of [REDACTED] GBtu in January 2026 and [REDACTED] GBtu in 2027, plus [REDACTED] and [REDACTED] basis hedges. NSPI also added [REDACTED] tonnes of [REDACTED] hedges for 2027.

XIII.B.1.c.ix. Portfolio-Level Assessment

We next reviewed NSPI's hedging activities' effectiveness on a portfolio level. We sought to review, using statistical metrics, the effectiveness of NSPI's entire hedging portfolio on its entire actual and forecasted fuel consumption costs and exposure. To do so, we looked at two metrics: (1) portfolio level regressions and (2) portfolio VaR. We address these items below. We conclude this section with (3) a look at the total transaction costs and fees associated with NSPI's hedging transactions and (4) NSPI's hedging procurement process.

XIII.B.1.c.x. Portfolio-Level Regression Analysis

Our first portfolio-level look at the effectiveness of NSPI's hedging activities was to consider how closely changes in the value of NSPI's hedge portfolio—comprised of both physical and financial positions—offset, or hedged, the value of NSPI's forecasted fuel consumption during the Audit Period, where these values are viewed as short positions. A short position in a product is defined as a position for which NSPI does not yet hold the product that it requires. Therefore, if NSPI is short and prices rise, it will be spending more to cover, or fill, its need.⁷⁸⁶ An effective hedge portfolio will rise in value if fuel prices rise, offsetting (moving opposite to) the increasingly larger cost required to meet need. As a result,

⁷⁸⁶ Being long on a product during a rise in price increases the value of your holdings. As a result, these portfolios move in opposite directions.

NSPI and its customers are insulated from rising fuel prices. To demonstrate whether this is true, linear regression analysis is appropriately used by NSPI. We reviewed NSPI's reported portfolio-level regression results and found that NSPI's overall hedge portfolio has been effective during the Audit Period.

The regression analysis measures how closely the day-to-day change in the market value of the hedge portfolio tracks the day-to-day change in the market value of NSPI's fuel consumption forecast costs. The two key outputs of the regression analysis are the slope of the regression line and the "R-squared" of the regression, which is a measure of how closely the regression line fits the data. The Fuel Hedging Plan defines an acceptable range for the former to be between -0.80 and -1.25 , and an acceptable range for the latter to be greater than or equal to 0.80 .⁷⁸⁷

As is shown below in Figure XIII-7, NSPI's portfolio of hedges was effective in all seven quarters of the Audit Period for which R-squared and regression were accessible as measured by the R-squared metric, but not effective in any quarter by the slope metric. For example, in the first quarter of 2024, NSPI's hedge portfolio had a slope of -0.76 , which means that for every dollar NSPI's expected fuel consumption costs increased for the remainder of the Audit Period, NSPI's hedge portfolio increased in value by 76 cents, though it had a sufficient R-squared value of 0.98 (implying an acceptable fit of the regression line to the data). It is notable that this pattern (effective according to R-squared, ineffective according to slope) was also observed across all quarters in the prior audit period.⁷⁸⁸

Figure XIII-7: Portfolio-Level Regression Analysis Output⁷⁸⁹

Quarter	Slope Coefficient	R-Squared
Q1 2024		0.98
Q2 2024		0.89
Q3 2024		0.81
Q4 2024		0.87
Q1 2025		
Q2 2025		0.96
Q3 2025		0.95
Q4 2025		0.87

In response to this, NSPI began calculating portfolio level results by year. For example, in its Q4 2025 analysis, NSPI completed regression analysis for 2025, 2026, and 2027, as well as for the overall portfolio (which includes all three years). That approach has shown NSPI that slope coefficients are better in the early years (in this example, 2025) and less effective in the outer years (in this example, 2027). This is a good process improvement and allows NSPI to better understand where its portfolio of hedges is most effective and where it is less effective. We also note that NSPI did not make any material changes to its

⁷⁸⁷ Fuel Hedging Plan, page 11.

⁷⁸⁸ 2022-2023 Bates White Audit Report, page 385.

⁷⁸⁹ Compiled from NSPI's quarterly hedge effectiveness reports.

hedging products, and the hedging program must be judged holistically across the menu of metrics laid out in the Fuel Hedging Plan. NSPI should continue to monitor this issue going forward to ensure that NSPI's chosen hedging products are effective. NSPI already presents its hedging effectiveness in quarterly updates to SWG, including calculated slope coefficients, so we do not include a recommendation on this point.

To help verify the regression statistics reported by NSPI, we requested that NSPI provide the data supporting the reported slope coefficient and R-squared statistics for Q4 2024. NSPI inadvertently provided data for Q4 2025, which matched the R-squared and slope coefficient for that quarter. NSPI later provided supporting data for Q4 2024, as requested; the supporting data matched the R-squared and slope coefficient for that quarter.

NSPI was unable to produce this analysis for Q1 2025 due to the loss of Allegro following the cyber event. NSPI explained that in order to assess portfolio effectiveness metrics, it must compare daily mark-to-market results over a given quarter. With no access to Allegro in the aftermath of the cyber event, NSPI could not do so. Moreover, once NSPI was able to backfill the pricing and trade data into Allegro, NSPI did so “in bulk,” meaning that the daily analysis needed to calculate mark-to-market changes of the period was not possible.

XIII.B.1.c.xi. Portfolio VaR

The second portfolio-level assessment we did of NSPI's hedging activities during the Audit Period was to consider NSPI's entire hedge portfolio's impact on NSPI's VaR. VaR is an industry standard risk measurement metric that calculates the dollars—or value—at risk given a particular holding period at a particular probability of loss. NSPI uses reasonable parameters in defining VaR, specifying a one-day holding period and a 95 percent confidence interval, while using the historical volatilities and correlations of the individual fuels over the previous 90 days.⁷⁹⁰ A VaR of \$5 million would imply that, assuming the volatilities in the prices of each fuel over the past 90 days, and the correlation between the prices of fuel over the past 90 days, NSPI has a risk of losing a maximum of \$5 million in the next day—subject to a 95% confidence interval. The higher the VaR relative to the value of the unhedged portfolio, the riskier the portfolio.

NSPI's decision to use 90 days of forward pricing in its hedging analysis is driven by the limited number of options offered in its risk management software—Allegro—which offers 32 days, 90 days, and six months of historical price data. This approach balances the competing forces of giving sufficient weight to more recent price volatility without having that volatility roll out of the calculation too quickly while also making sure periods of higher volatility are not included in the calculation too long, thereby artificially inflating the calculation, especially for commodities that exhibit seasonal price differences.

⁷⁹⁰ Fuel Hedging Plan, page 17.

If effective, NSPI's hedge portfolio will reduce NSPI's VaR. We found that NSPI's hedge portfolio was effective in significantly lowering NSPI's VaR. (NSPI was unable to produce this analysis for Q1 2025 due to the loss of Allegro following the cyber event.) For example, data for the first quarter of 2024 indicated that in the absence of hedging, the portfolio exposed customers to approximately \$7.7 million of value at risk for a one-day holding period; the hedged portfolio reduced this amount to approximately \$2.5 million,⁷⁹¹ a reduction in risk of approximately 66%. Results for each quarter of the Audit Period are presented in Figure XIII-8 below.

Figure XIII-8: Portfolio VaR Impact of NSPI's Hedging⁷⁹²

Quarter	Portfolio Effectiveness VaR
Q1 2024	-66%
Q2 2024	-46%
Q3 2024	-46%
Q4 2024	-53%
Q1 2025	Not available due to Cyber Incident
Q2 2025	-50%
Q3 2025	-53%
Q4 2025	-42%

To help verify the VaR calculations reported by NSPI, we requested that NSPI support the VaR reductions for Q4 2024. NSPI inadvertently provided data for Q4 2025, which supported and matches the VaR calculation for Q4 2025.

NSPI coordinates earlier in the process with Emera's ERM to discuss forecast assumptions and forecast scheduling and in recent years has increased communication with ERM to communicate NSPI's scheduled rebalance activities. NSPI also continued using its "what-if" analysis to assess the impact of hedge transactions on portfolio VaR. We reviewed output from the VaR model and found it reasonable.

XIII.B.1.c.xii. Portfolio Hedging Costs

Though effective by the measures noted above, NSPI's hedging activities have direct costs, and it is important to assess those costs and ensure they are not excessive relative to their risk-reducing benefits for NSPI's FAM customers. The Fuel Hedging Plan specifies that NSPI's hedge acquisitions will have costs that are neither "[REDACTED]" nor "[REDACTED]".⁷⁹³ Here, we note that these "costs" are not related to whether a given hedge transaction settles for a gain or loss, but rather the expenses associated with the transactions themselves.

⁷⁹¹ NSPI's 2024 Q1 Hedge Effectiveness Results Report, slide 5.

⁷⁹² Compiled from NSPI's eight quarterly hedge effectiveness reports.

⁷⁹³ Fuel Hedging Plan, page 15.

NSPI tracks hedging execution costs at a portfolio level. The costs include commissions and fees for transaction executions and services provided. These costs, which are recoverable through the FAM, are presented in Figure XIII-9 below. For the entire Audit Period, hedging costs totaled about USD \$ [REDACTED]. In addition, NSPI also incurs interest expenses (and accrues interest) in its margin accounts; such costs are not recoverable through the FAM. We find the FAM hedging costs to be reasonable given the volume of hedge transactions NSPI entered and given the size of the reductions in portfolio VaR (as shown in Figure XIII-8 above).

Figure XIII-9: Portfolio Hedging Costs (FAM recoverable, by Quarter)

Quarter	Hedging Costs (USD)
Q1 2024	[REDACTED]
Q2 2024	[REDACTED]
Q3 2024	[REDACTED]
Q4 2024	[REDACTED]
Q1 2025	[REDACTED]
Q2 2025	[REDACTED]
Q3 2025	[REDACTED]
Q4 2025	[REDACTED]
Total	[REDACTED]

We also note here that even though it is not a measure of hedge effectiveness, when a hedge settles, the realized gain or loss is reflected as an adjustment to the cost of inventory for storable fuels, such as solid fuel and oil, or as an adjustment to the cost of consumption for non-storable commodities such as natural gas and power.⁷⁹⁴ Where a recommended rebalancing will result in locking in a gain (or loss), this is noted in the quarterly portfolio re-balancing reports. NSPI's [REDACTED] on all financial hedge contracts was \$ [REDACTED] million in 2024 and \$ [REDACTED] million in 2025, or \$ [REDACTED] million for the entire Audit Period. Gains and losses on financial hedge contracts are driven by market conditions at the time of purchase and time of expiration (or unwinding). Losses on financial hedges that were procured during periods of higher market prices (such as in the prior audit period) and that expire during lower market prices are to be expected. In the prior audit period, the opposite was often true—note, for example, the second quarter 2022 crystallized [REDACTED] of \$ [REDACTED] million for an [REDACTED] hedge.⁷⁹⁵

When hedges settle, NSPI follows the process laid out in section 3.2 of the FAM Plan of Administration (“Allowable Fuel Costs”), which includes financial instruments used for hedging (including gains, losses, fees, and interest charges). Gains and losses on coal financial contracts (e.g., [REDACTED]) are assigned to “Solid Fuel” costs in FAM reports. Gains and losses on natural gas financial contracts (both [REDACTED] and basis contracts) are assigned to “Natural Gas” costs in FAM reports. Gains and losses on HFO financial contracts are assigned to “Bunker C” and gains and losses on financial

⁷⁹⁴ 2022-2023 Bates White Audit Report, page 387.

⁷⁹⁵ 2022-2023 Bates White Audit Report, page 382.

contracts for power (e.g., [REDACTED]) are assigned to “Import Purchases” in FAM reporting. Coal and HFO hedges are assigned to inventory, and the costs and benefits of those hedges are then realized in fuel costs when the inventory is consumed. Natural gas import power hedges are recognized in fuel costs in the period they are related to upon settlement.

XIII.B.1.c.xiii. NSPI's Hedge Procurement Process

NSPI's process for procuring hedges remains reasonable. NSPI can transact for hedges through a variety of vehicles, depending on the commodity, including the Intercontinental Exchange (“ICE”) platform, through use of a broker, and third-party institutions. These transactions are based on transparent market offers from counterparties and provide comfort that a transaction is made at a reasonable market-based cost. We observed that NSPI maintains master agreements⁷⁹⁶ with [REDACTED] counterparties⁷⁹⁷ that effectuate trading at standardized terms and conditions, limiting counterparty risk and lowering transaction costs. All of the transactions were through its primary broker, [REDACTED]. NSPI's transactions are executed by the traders for the underlying assets being hedged; for example, NSPI's gas hedges are executed by its natural gas traders, and its financial swap coal hedges are executed by its coal procurement experts.

As explained earlier, NSPI's process for procuring hedges includes a review and approval of the planned hedging transactions by FST. Approval of the planned transactions includes a target price for the transaction, which is based on the prior day's forward price activity (the mid-point transaction price on that day is selected). Traders then have authority to execute the transaction if they stay within a clearly-identified range of prices. This approach is a sound one, as it provides some flexibility to the trader to execute the transaction even if the markets have moved between the time of finalizing the target price and the time of the transaction, while also preventing hedge transactions at prices that no longer make sense for FAM customers due to larger shifts in market prices. Moreover, the approach gives the trader a clear brightline range of acceptable prices.

We observed unexecuted hedges in seven out of eight quarters. Reasons for these unexecuted hedges included price movement between the time of FST approval and time of attempted execution and a lack of sufficient liquidity in the respective markets. NSPI reported [REDACTED] in certain products, including summer [REDACTED] basis contracts and [REDACTED] contracts that are multiple years forward. In some cases, NSPI was able to fully execute all unexecuted hedges following its quarterly hedge reports. In all other cases, NSPI reassessed its portfolio exposure in its next quarterly PLEXOS forecast and rebalanced accordingly.

Given the increased number of unexecuted hedges as compared to the prior audit period, we reviewed the timing of NSPI's financial hedge trades relative to the date of the PLEXOS forecast on which the hedge procurement recommendations were based. The table below shows that, on average, [REDACTED] days elapsed between the date of the PLEXOS forecast and FST approval. Once traders had approval from the

⁷⁹⁶ Such agreements are International Swaps and Derivatives Association (“ISDA”) agreements.

⁷⁹⁷ Fuels Contracts, “ISDA.”

FST, they began transacting almost immediately, executing the first transaction one day after FST approval, on average.

Figure XIII-10: Quarterly PLEXOS Forecast, FST Approval, Hedge Transaction Timing

Forecast	Date of Forecast	Date of FST Approval	Date of First Trade	Days Between Forecast, FST Approval	Days Between Forecast, First Trade	Days Between FST Approval, First Trade
Q1 2024						
Q2 2024						
Q3 2024						
Q3 2024 (Interim)						
Q4 2024						
Q1 2025						
Q1 2025 (Interim)						
Q2 2025						
Q3 2025						
Q4 2025						

We recognize that FST approval is an important part of NSPI's process, and we understand that NSPI's subject matter experts take time to review PLEXOS outputs and prepare presentations for FST review. Still, during a ■-day period, a lot can change in energy markets, and prices for financial hedge contracts can increase beyond the range of approved price ranges, increasing the risk of unexecuted hedges. We therefore include a recommendation that NSPI review the timing of its hedging lifecycle—from PLEXOS forecasting, to FST presentation development, to FST approval—in order to find areas for increased efficiency.

XIII.B.1.d. Fuel-Level Hedge Assessment

Our next assessment was to consider NSPI's hedge effectiveness across individual fuels. This would demonstrate if NSPI's overall hedge portfolio results were masking any concerns regarding a particular fuel. To do this, we considered impact on VaR on a fuel-specific basis.

We found that NSPI's hedge portfolio was effective in significantly lowering NSPI's VaR in almost every case. (NSPI was unable to produce this analysis for Q1 2025 due to the loss of Allegro following the cyber event.). The fuel-specific percentage changes in VaR due to NSPI's hedging activities are shown in Figure XIII-11 below. The figure shows that NSPI's hedging significantly lowered VaR for solid fuel, natural gas, and power with consistency. All instances of positive VaR were limited to HFO, which is characterized by “lumpy” delivery volumes from individual cargoes that result in a mismatch on the annual forecast consumption of HFO due to limitations on storage.⁷⁹⁸

⁷⁹⁸ 2022-2023 Bates White Audit Report, page 388.

Figure XIII-11: Reduction in Value at Risk, by Fuel⁷⁹⁹

Quarter	Coal	Fuel Oil	Gas	Power
Q1 2024				
Q2 2024				
Q3 2024				
Q4 2024				
Q1 2025				
Q2 2025				
Q3 2025				
Q4 2025				

XIII.B.2. Bates White's 2022-2023 Audit Recommendations

We had no recommendations regarding Hedging in our prior Audit Report.

XIII.C. Conclusions

Conclusion XII-1: The hedging program as executed during the Audit Period generally conformed with the objectives of the Fuel Hedging Plan.

Conclusion XIII-2: Our review shows that NSPI conducted quarterly rebalancing activities consistent with the requirements of the Fuel Hedging Plan. The quarterly rebalancing used updated fuel consumption forecasts from Plexos that informed the need to enter additional hedges or unwind existing hedges to remain in compliance with the Fuel Hedging Plan.

Conclusion XIII-3: NSPI met the targets of its Fuel Hedging Plan for most fuels. By the end of 2024, NSPI had again hedged between [REDACTED] of all fuels except natural gas at basis price risk for 2025, but was [REDACTED] target on all fuels except for fuel oil in 2026. By the end of the Audit Period, NSPI reached the [REDACTED] target in all fuels for 2026 (including both natural gas at [REDACTED] and natural gas at basis price risk).

Conclusion XIII-4: NSPI's hedging was impacted by lower liquidity for certain products and certain periods, particularly for natural gas basis price risk.

Conclusion XIII-5: NSPI's hedging position was impacted by receipt of the SO₂ CoV in March 2025. NSPI appropriately conducted a special F&PP forecast and rebalanced its portfolio outside the regular quarterly rebalancing process.

Conclusion XII-6: NSPI's hedging decisions – and their success in shielding FAM ratepayers from volatile fuel costs – remain dependent upon the accuracy of NSPI's fuel consumption forecasts. Forecast

⁷⁹⁹ Compiled from NSPI's eight quarterly hedge effectiveness reports.

error could lead to hedged positions that either over- or under-state NSPI's true exposure to a given fuel's price, thereby increasing risks and/or costs faced by FAM customers.

Conclusion XIII-7: NSPI's hedging activities remain impacted by changes in the timing and volume of energy flows from NLH on the Maritime Link. Overall expectations of Maritime Link energy fell modestly during the Audit Period, though less than the declines observed in the prior audit period. For example, in its Q1 2024 forecast, NSPI forecasted [REDACTED] GWh of total Maritime Link imports in 2026; by the final forecast of the Audit Period (Q4 2025), NSPI expected [REDACTED] GWh in 2026, a decrease of [REDACTED] %.

Conclusion XIII-8: NSPI's forecasts of Base Block remained steady across the forecasts, staying at approximately 894 GWh/year in all forecasts. Forecasts for Supplemental Block were similar, but contained an error in all Audit Period forecasts through Q1 2025. The error, in which NSPI erroneously forecasted Supplemental Block deliveries in 2026, had no material impacts on NSPI's hedging decisions and was corrected in the Q2 2025 forecast.

Conclusion XIII-9: Forecasts of Surplus Energy were subject to material reductions during the Audit Period. In its Q1 2024 forecast, NSPI forecasted [REDACTED] GWh of Surplus Energy imports in 2026; by the final forecast of the Audit Period (Q4 2025), NSPI expected [REDACTED] GWh in 2026, a [REDACTED] of [REDACTED] %. Expectations for 2027 Surplus Energy also [REDACTED] albeit by a lesser degree, from an initial estimate of [REDACTED] GWh (in the Q3 2024 forecast) to 849 GWh (in the Q4 2025 forecast), a decrease of [REDACTED] %. These reductions were in part due to NSPI adopting a more conservative approach for estimating Surplus Energy, which resulted in a reduction in expected Surplus Energy based on greater operational experience.

Conclusion XIII-10: The impact of adjustments of Maritime Link energy forecasts on hedging activities can be significant. To the extent NSPI receives less actual Maritime Link energy in a period than was expected (and on which NSPI's hedging decisions were based), NSPI has to make up for those missing MWhs from other sources, including consumption of additional fuel at its power plants or through other imported energy, and in doing so, NSPI is exposed to market prices for fuel and purchased power. A further impact related specifically to changes in expected Surplus Energy volumes is a need to unwind financial hedges tied to the [REDACTED]. Whether these changes lead to incremental fuel costs or incremental fuel savings depends on how the market moved between the time the hedge was purchased and the time it was unwound.

Conclusion XIII-11: In the early F&PP forecasts conducted in the Audit Period to support hedging, NSPI assumed that PHP would become a FAM customer (with an embedded rate) starting in 2026. Accordingly, NSPI's PLEXOS forecast that was used to determine hedging decisions included PHP load starting in 2026. This is a departure from prior periods, when PHP was modeled as a below-the-line customer on its own tariff, and thus was not included in hedging decisions. With PHP's load included, the F&PP forecast results materially change. However, we observed [REDACTED] of this approach on hedging decisions during the Audit Period. Starting in the third quarter of 2024 and continuing through the end of

the Audit Period, NSPI no longer included 2026 PHP load in its hedging forecast. No hedges were unwound as a result of this decision, nor did we observe any unreasonable hedge positions for 2026 in the third quarter of 2024.

Conclusion XIII-12: In the Q2 2025 F&PP forecast, NSPI removed the expectation that Trenton 5 would be placed in cold storage (and thus not available to PLEXOS to commit and dispatch) starting in May 2027. NSPI explained that the cold storage of Trenton 5 is contingent on the addition of new fast acting generation capacity, which is the responsibility of the IESO, and which was behind in NSPI's original schedule for reaching commercial operation.

Conclusion XIII-13: NSPI employed an SO₂ emissions compliance buffer of 3 kt in 2024 and 6 kt 2025 due to tight SO₂ emissions limits. Those limits were relaxed in the near term when NSPI received its CoV.

Conclusion XIII-14: The hedging program has resulted in a significant decrease in the value at risk at the portfolio level. This has been achieved at a low cost.

Conclusion XIII-15: NSPI's portfolio of hedges was effective in all seven quarters of the Audit Period for which R-squared and regression were accessible as measured by the R-squared metric, but not effective in any quarter by the slope metric. In response to this, NSPI began calculating portfolio level results by year, which has shown NSPI that slope coefficients indicate higher effectiveness in for nearer-term hedge products. This is a good process improvement and allows NSPI to better understand where its portfolio of hedges is most effective and where it is less effective. NSPI should continue to monitor this issue going forward to ensure that NSPI's chosen hedging products are effective. NSPI already presents its hedging effectiveness in quarterly updates to SWG, including calculated slope coefficients, so we do not include a recommendation on this point.

Conclusion XIII-16: NSPI conducted appropriate rebalancing activities during the Audit Period, including interim rebalances such as that in response to the CoV.

Conclusion XIII-17: NSPI's process for developing a hedge transaction plan, receiving FST approval, and executing the transactions as contemplated by the plan is an effective process that provides NSPI's traders with clear guidelines on the transactions to be executed.

Conclusion XIII-18: Notwithstanding Conclusion XIII-20, we observed unexecuted hedges in seven out of eight quarters. On average, ■ days elapsed between the date of the PLEXOS forecast and FST approval. Once traders had approval from the FST, they began transacting almost immediately, executing the first transaction one day after FST approval, on average. Energy markets can change substantially during a ■-day period, and prices for financial hedge contracts can increase beyond the range of approved price ranges, increasing the risk of unexecuted hedges. We therefore include a recommendation that NSPI review the timing of its hedging lifecycle – from PLEXOS forecasting, to FST presentation development, to FST approval – to find areas for increased efficiency. **(Recommendation XIII-1)**

Conclusion XIII-19: The cyber event impacted some aspects of NSPI's hedging program performance tracking. NSPI was unable to produce a portfolio-level regression analysis for Q1 2025 due to the loss of access to Allegro in the aftermath of the cyber event. NSPI could also not produce its VaR analyses for Q1 2025 for the same reason.

Conclusion XIII-20: NSPI has access to [REDACTED] possible counterparties through ISDA Master Agreements, though all of its Audit Period financial hedging was done through its broker ([REDACTED]).

Conclusion XIII-21: Analysis of VaR at the individual fuel level indicates significant reductions in risk.

XIII.D. Recommendations

Recommendation XIII-1: NSPI should review the timing of its hedging lifecycle – from PLEXOS forecasting, to FST presentation development, to FST approval – to find areas for increased efficiency.

XIV. FAM Accounting⁸⁰⁰

XIV.A. Background

A 2009 NSEB order approved the implementation of NSPI's Fuel Adjustment Mechanism ("FAM"). The FAM provides for an annual adjustment to recover fuel and purchased power costs on a more current basis, in order to address the effects of volatile fuel and energy costs. The FAM reconciles the differences between actual fuel and energy costs and the corresponding base fuel and energy costs. Two deferral accounts drive annual changes in the costs recovered from customers through the FAM:

- AA (the Actual Adjustment): Tracks the difference in current fuel and energy costs from those reflected in the base cost of fuel or actual adjustment; and
- BA (the Balancing Adjustment): Compares costs actually recovered through AA to those intended to be recovered.

The difference between current costs and recoveries accrues carrying charges, which form part of the reconciliation of actual and base costs.

The scope of BDO's FAM accounting review for 2024 and 2025 ("Audit Period") included:

- Review of FAM accounting policy and procedures;
- Review and testing, on a sample basis, actual fuel and purchased power costs recorded in general ledger accounts, as provided for under the approved Plan of Administration ("POA");
- Review and testing, on a sample basis, differences between actual fuel and purchased power costs and those recovered under base rates;
- Verification of the weighted average costs of capital and interest rates in connection with over (under) recoveries of actual fuel and purchased power costs.

On April 25, 2025, Nova Scotia Power Inc. identified a cybersecurity incident involving unauthorized access to portions of its information technology network and servers supporting business applications. While the incident did not disrupt NSPI's physical operations, it had a significant impact on financial reporting systems and underlying accounting data. As a result of the incident, NSPI lost access to its primary enterprise resource planning system, Oracle EBS, and the underlying transaction data lost and substantially recovered through saved files on NSPI's local files or files previously provided to NSPI's external auditor, Ernst & Young, LLP, during their 2024 and 2025 financial audit. In response to the

⁸⁰⁰ This chapter was primarily authored by BDO and reviewed by Bates White.

cybersecurity incident, management implemented business continuity procedures and alternative processes to allow for continued financial reporting, including the use of manually maintained records. NSPI transitioned to a new ERP system, Oracle Fusion, beginning in September 2025; however, this system currently does not have any historical general ledger details other than ending balances and does not fully integrate with subledger systems. Considering the cybersecurity incident, BDO's procedures emphasized substantive testing, expanded sample sizes when compared to the prior year engagement, and increased corroboration of financial data. Accordingly, we substantially increased our overall planned sample sizes and broadened the nature of transactions selected for detailed testing to address the heightened risk arising from the incident, including Carbon Tax credits, Hydro Royalties, IPP Wind, and COMFIT purchased power selections. In addition, samples selected for purchased power credits, which were already included within the planned scope of testing, were increased as part of our enhanced substantive procedures. Although the incident significantly increased complexity and risk, sufficient appropriate audit evidence was obtained through enhanced procedures, and the financial statements can still be assessed as fairly presented when properly supported.

XIV.B. Findings

XIV.B.1. FAM Accounting – Fuel and Purchased Power Cost

BDO reviewed NSPI's financial accounting process and inspected detailed financial accounting records that support the actual cost of fuel and purchased power claimed. BDO conducted a remote review to examine documents and supporting work papers, and to discuss processes, procedures, systems, documentation, and FAM reporting with NSPI personnel.

BDO sampled over 200 accounting transactions from January 2024 through December 2025 and performed test procedures on selected entries that included related supporting accounting documents. BDO tested four months of the FAM model calculations by verifying the weighted average cost of capital and interest rates in connection with over (under) recoveries of actual fuel and purchased power cost. BDO obtained supporting schedules to understand the inputs of the underlying FAM model. BDO also reviewed organization charts, chart of accounts, cost-center and project activity codes, general policies, and procedures. We examined accounting process flowcharts related to fuel and purchased power procurement, energy marketing documents, and supporting accounting information pertaining to the FAM's cost components. BDO held discussions with NSPI team members responsible for creation and maintenance of accounting records and for preparation of monthly, quarterly, and annual FAM reports, statements, and supporting documents.

BDO sought to determine whether NSPI maintains its FAM accounting and reporting information in a manner that facilitates a level of verification and audit procedures customarily associated with fuel adjustment mechanisms overseen by regulators.

XIV.B.2. Accounting Resources for FAM Administration

The Plan of Administration (“POA”) serves as the principal governing document for FAM accounting. This plan sets forth the policies and procedures guiding FAM calculation and determining allowed costs. NSPI also employs other accounting policies and procedures that have relevance to fuel and purchased power costs. They provide the administrative and accounting procedures that ensure that costs have been reasonably and accurately reported. BDO found NSPI’s accounting personnel to be knowledgeable of the FAM accounting and reporting processes, and familiar with the detailed, supporting work papers.

NSPI continued to maintain a formal accounting flow chart and operates under a clear chain of reporting in those organizations responsible for FAM-related accounting activities. These organizations include the Controller, Senior Manager of Fuels Planning & Performance, and Manager of Fuels Accounting & Reporting.

A formal POA continues to contain the necessary supporting procedures and accounting and reporting checklists. NSPI also maintains appropriate accounting policies and procedures. They adequately address accounting for fuel and purchased power expense.

The systems and tools that NSPI uses for fuel and energy accounting and reporting include an appropriate overall accounting system and an appropriate chart of accounts, which have numbers and definitions sufficient to define adequately the accounts, activities, cost centers, and project codes necessary for FAM operation and calculations. Prior to April 2025, NSPI used an Oracle Accounting System to maintain its general ledger. Align and Horizon (formerly known as Allegro) serve as subledgers supporting fuel inventory, purchased power, hedging, and natural gas accounting. Prior to the system upgrade to Horizon in July 2024, these systems interfaced with Oracle; however, the interfaces are no longer operational, requiring NSPI to manually record journal entries in the Oracle Fusion general ledger. As mentioned above, NSPI implemented Oracle Fusion which continued to not have the ability to interface with any other systems/subledgers from July 2024 through year-end 2025; however, NSPI confirmed Align interfaces with Oracle Fusion as of June 2026. From April 2025 through December 2025, NSPI maintained manual Microsoft Excel worksheets for valuation of inventory and purchased power, which was created from underlying support such as invoices, consumption calculation, meter reports, etc. Additionally, NSPI performed variance reporting in key areas of sales information, foreign exchange, and other related fuel and purchased power activity in order to understand significant or unusual activity.

BDO found NSPI’s accounting and reporting organizational structure and staff suitable for FAM accounting and administration purposes. Further, BDO found that the accounting department exercised reasonable oversight and direction of its staff.

XIV.B.3. FAM Reports to the Board

The general context of the accounting resources, including the FAM tools and administration described above, provide the backbone information used to compile the monthly/quarterly/annual FAM reports submitted to the Board. NSPI prepares these reports under process checklists to which its personnel adhere. NSPI continues to maintain a formal FAM in-house review and approval process. The process provides for a stepped level of review by key personnel, who review and comment on the draft monthly/quarterly/annual FAM filings to be submitted to the Board.

XIV.B.4. FAM Accounting Policies and Procedures Verification

BDO tested and verified NSPI's FAM accounting policies and procedures that underline fuel and purchased power costs reported for the Audit Period. This portion of BDO's work included testing of transactions in various months of the Audit Period.

BDO requested and received copies of NSPI's general accounting policies and procedures and process flowcharts for fuel and purchased power procurement and inventory, as well as energy marketing.

NSPI's updated documents indicated an effective date as of the first quarter of 2026.

XIV.B.5. Fuel and Purchased Power Accounting Verification

As it has done before, NSPI continued to maintain vendor master files and adheres to organization and authority approval levels for fuel and purchased power procurement. Data from purchase requisitions, purchase orders, and contracts effectively flowed through Align, Horizon and Oracle as required. The data included contract change authorizations. Monitoring includes cross checks, and provides for reconciliations and any necessary adjustments.

BDO's review and testing of fuel procurement, invoicing, and verification process demonstrated conformity between costs contracted and costs paid.

BDO's review of the Chart of Accounts and definitions identified account designation, activity, cost center, and project codes related to FAM fuel and purchased power costs. BDO obtained detailed general ledger activity for each FAM account listed in the POA, and for other accounts affecting the FAM. BDO tested a sample of January 2024 through December 2025 activity by tracing activity to the sub ledger, original and adjusting journal entries, and accrual entries to supporting work papers, such as invoices, agreements, purchase orders, calculations, etc. BDO found no exceptions with the costs reported.

Due to the cyber security incident, BDO obtained the Company's manual schedules mainly related to fuel inventories and purchased power activity in order to trace amount recorded as fuel and purchased power costs to the general ledger and agree the manual schedules to underlying support. We traced, cross checked and reconciled information on a sample basis. These procedures disclosed no findings.

XIV.B.6. Fuel Master Agreements and Purchase Order Controls Verification

BDO's review and testing of fuel procurement, invoicing, and verification processes did not disclose any instances where costs paid for fuels procured exceed contractually agreed upon prices. BDO tracked and compared master agreement information maintained within the Fuel Energy & Risk Management department with data from Fuel Accounting. We encountered no difficulties in obtaining clear and concise information on master agreements.

The purchase order numbers assigned to agreements change annually. However, some agreements remain in effect for periods greater than a year. Moreover, some vendors have multiple agreements with NSPI. Invoices accurately reflect the annually assigned purchase orders. BDO was able to identify purchase orders were properly approved based on the relevant support provided. The approval documentation from Oracle displays the purchase order number in which proper approval was obtained.

Due to a cyber security incident that compromised data in April 2025, payment support related to certain testing samples was either unavailable or not readily obtainable because NSPI was unable to easily drill down by invoice number into the system to evidence payment support. In order to maintain consistency in our testing methodology for both fiscal years ended 12/31/2024 and 12/31/2025, BDO opted to obtain an Align cost allocation screenshot as alternative audit evidence to support that the costs were incurred and paid, and inspected each, agreeing invoice numbers and invoiced amounts to other supporting documentation as referenced in each testing selection above. The Align screenshot reflects the allocated expenses and includes evidence of payment and appropriate approval. No exceptions were noted (see recommendation below).

Additionally, for hedge settlement testing, BDO was unable to obtain credit exposure reports for any samples prior to July 2024 due to the Horizon system upgrade as mentioned above. BDO noted this as an exception in our testing as we were unable to review the day's selected credit report to ensure that open positions were available that day and thus the sampled hedge transaction was executed appropriately. However, BDO obtained the counterparty settlement confirmation of the trade and agreed to the Horizon subledger noting no exceptions for our samples tested.

XIV.B.7. FAM Process Accounting and Controls Verification

NSPI's accounting department generally has continued since the last Audit Period to rely on the same activities and reporting checklists when preparing monthly FAM accounting support for FAM filings. BDO reviewed and tested the overall accounting controls to verify that they support thorough and accurate FAM cost reporting. BDO found the senior and manager level accounting staff to be appropriately engaged in the review and oversight process. Their activities include documented sign offs of necessary accounting documents.

BDO selected a sample of fuel transactions, including solid fuel, purchased power, liquid fuels and MTM transactions from the audit period January 1, 2024, to December 31, 2025, for testing of FAM

related accounting controls related to the purchase and recording of fuel costs. BDO obtained supporting documentation related to the transactions and ensured controls were operating effectively during the period. These procedures disclosed no findings.

XIV.B.8. Accounting System Flexfield Codes

NSPI's Chart of Accounts includes information that describes its fourteen-digit "Accounting Flexfiled" code system. This five-segment system allows for unique identification by company, account, activity, cost centers, and project. BDO reviewed the consistency of cost classification through review of detailed general ledger account activity information, transaction testing on a number of the major cost elements, testing of related adjusting entries and supporting data, and review of additional supporting details.

Our examination disclosed no reason for concern about the consistency of the classification of costs within the appropriate accounts, nor did it disclose any material differences between underlying FAM cost recorded and those reported. NSPI's accounting system, including supporting work papers, provided sufficient and reasonable transparency for analyzing costs associated with the various FAM cost elements. NSPI's work papers and supporting documents supported the ability to query and extract information from systems.

XIV.B.9. FAM Model Calculation – Weighted Average Cost of Capital and Interest Rates related to recoveries of Actual Fuel and Purchase Power Costs

BDO's review and testing of the FAM model calculation for 4 months during the audit period included inquiring of management in order to gain an understanding of the FAM model calculation, verifying the inputs used to calculate the weighted average cost of capital and interest costs in connection to over (under) recoveries of actual fuel and purchased power costs by obtaining and inspecting supporting schedules and NSEB Board Orders meetings minutes, and clerically testing FAM model calculation in order to agree the inputs to underlying data. During these testing procedures, BDO did not identify any errors or inconsistencies related to the inputs of the calculation. BDO concluded the FAM model accurately applies the weighted average cost of capital and interest rates in connection to over (under) recoveries of actual fuel and purchased power costs.

XIV.B.10. Bates White's 2022-2023 Audit Recommendations

In our prior audit report, BDO provided one recommendation regarding FAM Accounting. The recommendation was:

Recommendation XIV-1: NSPI should include contract numbers and purchase order numbers on all purchase order documents to easily identify and agree the approvals of the purchase order displayed in the system to the purchase order document.

NSPI accepted this recommendation and stated that it would “amend the process to update documents once a related automated purchase order number has been generated.” We noted in our Rebuttal Evidence that we considered NSPI’s response to be “positive and satisfactory.”⁸⁰¹ NSPI stated in its February 2026 2022-2023 FAM Audit Action Plan Update that it “has completed including contract numbers and purchase order numbers on both new purchases and prior documents.” BDO’s review confirmed that this recommendation has been fully addressed.

XIV.C. Conclusions

Conclusion XIV-1: While the April 2025 cybersecurity incident increased the complexity and risk associated with the audit, it did not materially impair BDO’s ability to perform the planned audit procedures or reach its conclusions. Through the use of enhanced substantive testing, expanded sample selections, alternative supporting documentation, and additional corroborative procedures, BDO obtained sufficient appropriate audit evidence to support the fuel and purchased power costs included in the FAM. Other than the specific observations and recommendations noted in this report regarding documentation and audit trail enhancements, the cybersecurity incident did not result in any significant limitations to the audit procedures performed or affect BDO’s overall conclusions regarding FAM administration, accounting, reporting, and cost recovery.

Conclusion XIV-2: NSPI applies suitable accounting resources, systems, tools, and methods to FAM administration. NSPI provides reasonable oversight and direction of accounting for fuel and energy transactions affecting FAM operations. Personnel in the fuel procurement and accounting departments exercised reasonable oversight and direction of staff in performing activities related to the FAM administration.

Conclusion XIV-3: Fuel and purchased power accounting are sufficient. NSPI’s accounting system for solid and liquid fuels and for natural gas employs Aligné, Horizon, and Oracle, along with stand-alone Microsoft Excel spreadsheets used for supporting calculations and analysis. Supply contracts are set up and maintained in the inventory master file in Aligné and data from the Process Information (PI) system feeds Aligné. This system automatically calculates the weighted-average unit cost of inventory used to record consumption. The spreadsheet processes gas and power revenue, purchases, receivables, and payables.

Conclusion XIV-4: All related fuel and purchased power costs (solid and liquid fuels, gas and purchased power and MTM, for example) included in the FAM are supported by detailed documents and a review process that includes controlled accrual and adjusting entries. BDO’s review indicated that these controls and procedures were applied consistently and appropriately throughout the audit period.

⁸⁰¹ Bates White Rebuttal Evidence, M11533, February 21, 2025, page 7 line 16.

Conclusion XIV-5: BDO's review of fuel purchase accounting also included proper approval of payments related to fuel purchases. The process for approving payments is summarized in the Fuel Manual and includes a monetary threshold hierarchy for approval. BDO's review and testing found NSPI is appropriately following the Fuel Manual policy and procedures.

Conclusion XIV-6: Based on review of NSPI's FAM model, BDO concludes the FAM model accurately applies the weighted average cost of capital and interest costs in connection with over (under) recoveries of actual fuel and purchased power costs based on inputs supported by rates approved by the NSEB and underlying supporting schedules, such as forecast vs. actual monthly reports, and sales and costs reports.

Conclusion XIV-7: NSPI should maintain a detailed listing of invoices included in each payment batch to enhance the audit trail of cash disbursements. The listing should identify the invoices processed, related vendors, payment amounts, payment dates, and batch references to provide a complete audit trail and support management's review of cash disbursements. Maintaining this documentation would strengthen internal controls, improve payment tracking, and reduce the risk of duplicate or unauthorized payments.
(Recommendation XIV-1)

Conclusion XIV-8: NSPI fully addressed the one recommendation related to FAM Accounting from the prior audit period.

XIV.D. Recommendations

Recommendation XIV-1: NSPI should maintain a detailed listing of invoices included in each payment batch to enhance the audit trail of cash disbursements. The listing should identify the invoices processed, related vendors, payment amounts, payment dates, and batch references to provide a complete audit trail and support management's review of cash disbursements.

XV. ELIADC

XV.A. Background

Port Hawkesbury Paper (“PHP”) has been taking service under the Extra Large Industrial Active Demand Control Tariff (“ELIADC”) since January 1, 2020. The Tariff was approved for an initial term of three years, 2020-2023.⁸⁰² On August 24, 2023, NSPI applied to the Board to extend the ELIADC tariff for two years starting January 1, 2024 through December 31, 2025 stating that the extension would allow PHP and NSPI to develop the terms of a new rate structure that could work in conjunction with the Goose Harbour Lake Wind Farm (“Goose Harbour”) in development by PHP and expected to begin commercial operations in late 2025.⁸⁰³ The Board approved the requested ELIADC tariff extension on December 20, 2023.⁸⁰⁴ On March 31, 2025, NSPI applied to the Board for a second extension starting January 1, 2026 through December 31, 2026.⁸⁰⁵ The Board approved the second extension request on December 8, 2025.

The ELIADC’s essential features are:

- The ELIADC Tariff is a specialized tariff applicable only to PHP’s operations at the Point Tupper mill site.⁸⁰⁶
- The ELIADC requires that PHP pay for all variable incremental costs incurred by NSPI to serve PHP’s load including variable energy and variable capital costs, plus a contribution to fixed cost of at least \$4.00/MWh.⁸⁰⁷
- The ELIADC is designed to promote economically efficient scheduling and use of electric power by allowing NSPI to co-optimize PHP’s demand as part of the full NSPI portfolio and to adjust PHP load in real time to optimize generation and respond to system events.

The ELIADC was conceived as an innovative tariff to allow for improved efficiency of serving PHP’s load and increased benefits to other NSPI customers. Over the period that the Tariff has been in place, we have learned that cost savings from co-optimized schedules cannot be accurately determined using the methodology proposed by NSPI and approved by the Board due to fuel prices that vary from forecast and changes in PHP’s load. Also, cost savings from real-time active demand control cannot even be measured.

⁸⁰² NSUARB, “Decision,” M09420, March 26, 2020, (“2020 ELIADC Tariff Decision”).

⁸⁰³ Nova Scotia Power Application for Approval of a Subsequent Term For the Extra Large Industrial Active Demand Control Tariff, M11301, August 24, 2023, M11301. Available at: <https://uarb.novascotia.ca/fmi/webd/UARB15>.

⁸⁰⁴ “Decision and Order”, Nova Scotia Utility and Review Board, 2023 NSUARB 226, M11301, December 20, 2023.

⁸⁰⁵ Nova Scotia Power Application for Approval of a Third Term for the Extra Large Industrial Active Demand Control Tariff, M12184, March 31, 2025. Available at: <https://uarb.novascotia.ca/fmi/webd/UARB15>.

⁸⁰⁶ 2024-2025 ELIADC Tariff, p. 1.

⁸⁰⁷ 2024-2025 ELIADC Tariff, p. 1-2.

However, using NSPI's metrics stipulated in the ELIADC tariff, the recorded benefit to FAM customers in 2024 was the mandatory contribution to fixed costs of \$4.00/MWh or \$3.06 million. In 2025, the benefit was determined to be \$6.42/MWh or \$4.43 million. These measured benefits, largely composed of the mandatory contribution to fixed costs,⁸⁰⁸ are much smaller than those anticipated when the ELIADC tariff was put in place.⁸⁰⁹ (**Recommendation XV-1**)

XV.B. Findings

XV.B.1. Implementation of the ELIADC

There are several important features of the ELIADC that relate to active demand control and pricing:

- PHP's load is incorporated within PortOps during the Day Ahead and Intra Day schedule creation and optimized to determine the least cost constrained dispatch, with PHP load essentially represented as a negative generator. PHP's load as represented in PortOps is not fully dispatchable in every hour – i.e., from zero to maximum load – but is subject to various constraints based on defined operating modes (“OMs”) for the PHP facility, including consideration of available pulp storage over time.
- For a given calendar year, PHP pays a fixed rate for energy that is determined in advance of the year based on a forecast of the incremental cost to serve PHP at an assumed level baseline load level. Several adders and adjustments apply to provide a contribution to system costs and to share in benefits from active demand control.⁸¹⁰
- PHP is obligated to pay the full actual cost to serve its load, including any costs arising from PHP deviating from dispatch schedules issued by NSPI. The ELIADC requires a minimum annual payment of the actual total incremental cost plus \$4.00/MWh. Any additional amounts required to achieve this minimum are determined and charged to PHP after year end.⁸¹¹
- As a result of the 2025 cyber incident, the PortOps model that is used to co-optimize PHP load with system resources to serve FAM load, was not available from April 25, 2025 through the end of the Audit Period.⁸¹² For the period April 25, 2025 through May 25, 2025 no Day Ahead Schedules for PHP were produced. Day Ahead Schedules for PHP resumed on May 26, 2025.⁸¹³ During the remainder of the year, NSPI used PLEXOS to determine Day

⁸⁰⁸ The mandatory contribution to fixed costs is to ensure that PHP contributes to the fixed costs of the system. See 2024-2025 ELIADC Tariff, p. 2.

⁸⁰⁹ 2020 ELIADC Tariff Decision, p. 4.

⁸¹⁰ 2024-2025 ELIADC Tariff, p. 1

⁸¹¹ 2024-2025 ELIADC Tariff, p. 1-2.

⁸¹² PortOps was restored in Q1 2026.

⁸¹³ ELIADC Tariff 2025 Annual Report (NSEB M12768).

Ahead schedules. PLEXOS was not run every day, but about every three days or so and on a more frequent basis if needed to verify unit commitment. Thus, on many days, the Day Ahead Schedule was constructed manually based on PLEXOS runs that were more than one day old. For the period April 25, 2025 to August 5, 2025, no intra-day (a.k.a. real-time) schedules were produced. During this period the marketing desk and the NSPSO worked with PHP to determine PHP's hourly load. Starting on August 5, 2025, real-time schedules were constructed manually using information provided by PLEXOS runs.

XV.B.1.a. ELIADC Price Components

There are four main charge elements under the ELIADC:

1. Customer Baseline Energy Charge ("CBL Energy Charge")
2. Customer Baseline Adder ("CBLA")
3. Variable Capital Charge ("VCC")
4. Active Demand Control Credit ("ADC Credit")⁸¹⁴

In addition, PHP is subject to additional adjustments to capture (1) costs associated with deviating from dispatch instructions, (2) any additional amount required to meet the minimum payment equal to all incremental cost of service plus \$4.00/MWh, and (3) any ADC benefits equal to 25 percent of the cost differential between the CBL Energy Charge and the actual cost to serve PHP.⁸¹⁵

CBL Energy Charge

The CBL Energy Charge includes all incremental, non-capital costs to serve PHP load.⁸¹⁶ Prior to each tariff year, PHP is required to provide NSPI a forecast of annual and monthly energy requirements, including anticipated scheduled maintenance.⁸¹⁷ On the basis of this forecast information, NSPI projects the cost to serve PHP at a constant hourly baseline load using forecast incremental costs, which results in a single flat energy rate, the CBL Energy Charge, in \$/MWh.⁸¹⁸ Figure XV-1 shows the approved CBL Energy Charges in the 2020-2025 period. Note that CBL Energy Charge is a monthly charge and therefore more than one CBL Energy Charge can be in effect during any calendar year.

⁸¹⁴ 2024-2025 ELIADC Tariff, p. 1.

⁸¹⁵ 2024-2025 ELIADC Tariff, p. 2, 4.

⁸¹⁶ 2024-2025 ELIADC Tariff, p. 2.

⁸¹⁷ 2024-2025 ELIADC Tariff, p. 2.

⁸¹⁸ 2024-2025 ELIADC Tariff, p. 2.

Figure XV-1: CBL Energy Charge, \$/MWh⁸¹⁹

Tariff	Period	CBL Energy Charge
ELIADC	2020	\$59.99
	2021	\$53.02
	2022	\$57.99
	January 1 2023 - February 29 2024	\$57.99
	March 1 2024 - January 31 2025	\$101.65
	February 1 2025 - December 31 2025	\$96.00

On July 5, 2023, the Board approved a change in the method to calculate the actual total incremental cost to serve. The original method, based on forecast replacement costs for fuel, was replaced with one based on historical weighted average fuel costs.⁸²⁰ The methodology change to calculate the actual cost to serve PHP did not affect the calculation of the CBL Energy Charge which is based on an estimate of *future* incremental costs to serve PHP at a constant hourly baseline load.

CBLA

The Customer Baseline Adder is a charge to PHP “to contribute to the reduction of the cost of service to other NS Power customers.”⁸²¹ It is determined relative to a reference rate specified in the tariff, which has been \$61.75/MWh in every year since the tariff was implemented.⁸²² When the CBL Energy Charge is less than \$61.75/MWh, the CBLA is calculated as 75 percent of the positive difference between \$61.75/MWh and the CBL Energy Charge plus \$1/MWh. If the CBL Energy Charge is greater than \$61.75/MWh, the CBLA is assigned a value of \$1/MWh.⁸²³ A consequence of this formulation is that the CBLA decreases as the CBL Energy Charge increases and has a minimum value of \$1/MWh.

Starting in March of 2024, CBL Energy Charge was greater than the \$61.75/MWh reference rate, thus the CBLA had a value of \$1 for the months of March through December in 2024 and in all months of 2025. For January and February, it was calculated in accordance with the above formula similar to the years 2020 through 2023.

For 2020-2023, and the first two months of 2024, the CBLA was calculated as follows:

$$\text{January 1, 2022 – February 29, 2024 CBLA} = 75\% \times (\$61.75 - \$57.99) + \$1 = \$3.82/\text{MWh}$$

$$\text{2021 CBLA} = 75\% \times (\$61.75 - \$53.02) + \$1 = \$7.55/\text{MWh}$$

⁸¹⁹ 2022-2023 Bates White Audit Report, page 402.

⁸²⁰ The new methodology uses the weighted average cost of fuel inventories removing any financial impact of hedge transactions. See NSUARB, “Board Decision Letter”, M11021, July 5 2023, p. 2.

⁸²¹ 2024-2025 ELIADC Tariff, p. 1.

⁸²² 2024-2025 ELIADC Tariff, p. 2.

⁸²³ 2024-2025 ELIADC Tariff, p. 2.

$$2020 \text{ CBLA} = 75\% \times (\$61.75 - \$59.99) + \$1 = \$2.32/\text{MWh}$$

The CBLA is an adder that provides recovery above the CBL Energy Charge. As such, the CBLA makes up a portion of the minimum required \$4/MWh contribution to fixed costs.

VCC

NSPI forecasts the Variable Capital Charge annually by comparing NSPI's generation fleet dispatch with and without PHP on the system, and determining the change in required sustaining capital. The comparison and calculations are done prior to the Audit Period and are not updated after the fact. The comparison uses a utilization factor that considers a unit's capacity factor, service hours, cycles, and asset health. The VCCs for 2020 through 2025 are shown in Figure XV-2. Note that for 2023, the VCC was increased to \$3.00/MWh on June 7, 2023.

Figure XV-2: Variable Capital Charge, \$/MWh⁸²⁴

Tariff	Period	VCC
ELIADC	2020	\$1.13
	2021	\$1.79
	January 1 2022 - June 6 2023	\$1.81
	June 7 2023 - February 29 2024	\$3.00
	March 1 2024 - January 31 2025	\$4.64
	February 1 2025 - December 31 2025	\$3.34

In 2024, there was an estimated increase in sustaining capital costs for Lingan 1, Lingan 3, and Lingan 4 to serve PHP load of \$953,667 each. There was also an estimated increase for Trenton 6 of \$999,297 and for Tufts Cove 1 of \$865,086. In total, the estimated increase in sustaining capital costs was \$4,725,384. PHP's estimated load for 2024 was 813.24 GWh resulting in a cost per MWh of \$5.81. This cost was later revised to \$4.64/MWh and implemented in March 2024, resulting in total VOC costs of \$3,380,089.⁸²⁵ The 2024 VCC increased by 14% as compared to 2023, from \$2,954,941 to \$3,380,089.

In 2025, sustaining capital costs to serve PHP load accrued to Lingan 4 in the amount of \$1,055,709, Tufts Cove 2 in the amount of \$882,928 and Tufts Cove 3 in the amount of \$769,052 for a total estimated increase in sustaining capital costs of \$2,707,689. PHP's estimated load for 2025 was 810.55 GWh resulting in a cost per MWh of \$3.34. The VCC was implemented in February 2025, resulting in total VOC costs of \$2,373,719.⁸²⁶ The 2025 VOC decreased by 30% as compared to 2023, from \$3,380,089 to \$2,373,719.

ELIADC Energy Charge

⁸²⁴ 2022-2023 Bates White Audit Report, page 403.

⁸²⁵ ELIADC 2024 Annual Report, data appendix.

⁸²⁶ ELIADC 2025 Annual Report, data appendix.

The charges above combine to give the ELIADC Energy Charge:

$$ELIADC \text{ Energy Charge} = CBL \text{ Energy Charge} + CBLA + VCC^{827}$$

Figure XV-3 shows the ELIADC Energy Charge for the 2020-2025 period.

Figure XV-3: ELIADC Energy Charge, \$/MWh⁸²⁸

Tariff	Period	Energy Charge
ELIADC	2020	\$63.44
	2021	\$62.36
	January 1 2022 - June 6 2023	\$63.62
	June 7 2023 - February 29 2024	\$64.81
	March 1 2024 - January 31 2025	\$107.29
	February 1 2025 - December 31 2025	\$100.34

ADC Credit

The ADC Credit is an adjustment calculated at the conclusion of the tariff year to share the system savings benefit of active demand control between FAM customers and PHP. PHP is entitled to 25% of the calculated benefit. When the CBL Energy Charge payments made by PHP are greater than the actual cost to serve PHP, the ADC benefit is calculated as the difference between the fuel and purchased power (“F&PP”) and variable operating and maintenance costs (“VOM”) in the CBL Energy Charge, and the actual annual F&PP and VOM costs to serve PHP.⁸²⁹ When CBL Energy Charge payments are less than the actual annual cost to serve PHP, there are no defined ADC Credits.⁸³⁰

Under the ELIADC Tariff, PHP must make a minimum annual payment not less than the sum of:

- a. NS Power’s actual total incremental cost⁸³¹ of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power’s incremental generation and delivery of electricity to the customer), plus

⁸²⁷ 2024-2025 ELIADC Tariff, p.3.

⁸²⁸ ELIADC tariff, NSPI Tariffs effective April 1, 2020, page 69 of 122; ELIADC tariff, NSPI Tariffs effective February 1, 2021, page 71 of 117; 2022-2023 Bates White Audit Report, page 404.

⁸²⁹ 2024-2025 ELIADC Tariff, p. 4.

⁸³⁰ In addition to the F&PP and VOM costs, the CBL Energy Charge contains a fixed cost component which is equal to the actual amount collected and thus does not impact the ADC Credit. *See* 2024-2025 ELIADC Tariff, p. 2.

⁸³¹ Although technically incorrect, the phrase “incremental cost” has not been modified in the tariff. PHP does not pay incremental F&PP costs but rather the weighted average costs of fuel inventories. *See* NSUARB, “Board Decision Letter”, M11021, July 5 2023, p. 2.

b. \$4.00 multiplied by the total number of MWh supplied in the year.⁸³²

In 2024, actual costs to serve PHP load were greater than the CBL Energy Charge payments resulting in zero defined ADC benefits and requiring an additional payment from PHP of \$793,171 after the end of the year as shown in Figure XV-4.

In 2025, the actual cost to serve PHP was less than the CBL Energy Charge payments resulting in a defined ADC benefit of \$1,522,611. As required under the tariff, the benefit is split between FAM customers and PHP 75%/25% respectively resulting in an allocation to FAM customers of \$1,141,958 and an allocation to PHP of \$380,653.

The ELIADC tariff also requires payment for costs associated with PHP unilateral deviations from real-time schedules (“Off Schedule Charge”). The total Off-Schedule Charge associated with PHP unilateral deviations in 2025 was \$706,609. NSPI reduced this amount by 25% (a reduction of \$176,652) to \$529,957 and netted it with the CBL Credit resulting in an assessment of net costs to PHP of \$149,304. This is shown in Figure XV-4.

Figure XV-4: PHP Costs and Payments⁸³³

Year	Total Delivered Energy (MWh)	Total Billed Charge	Total Cost to Serve PHP Load	ADC Benefit	Off Schedule Charge	Additional PHP Payment
2020		\$55,507,679	\$45,864,745	\$6,624,312	\$276,000	N/A
2021		\$60,229,668	\$67,872,401	\$0	*	\$7,642,733
2022		\$60,872,160	\$109,750,513	\$0	*	\$48,878,353
2023		\$43,125,988	\$76,766,605	\$0	*	\$33,640,617
2024		\$77,678,733	\$78,471,904	\$0	*	\$793,171
2025		\$69,664,627	\$68,142,015	\$1,522,611	\$529,957	\$149,304

*Included in Total Cost to Serve PHP Load.

NSPI reduced the Off Schedule Charge by 31.6% in the 2020 ELIADC annual report and set the Off Schedule Charge to zero in every other year through 2024.⁸³⁴ As we explain in more detail in our evaluation of NSPI’s response to 2022-2023 Recommendation XV-1 discussed further below, we find no basis for a reduction in the Off Schedule Charge by 25% in 2025. We note that the 2024-2025 ELIADC tariff states that,

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, *taking account of the impacts of any variances by PHP from the*

⁸³² 2023 ELIADC Tariff, pages 1-2.

⁸³³ 2020-2021 Bates White Audit Report, page 381; 2022-2023 Bates White Audit Report, page 406.

⁸³⁴ 2024-2025 ELIADC Tariff, p. 4.

dispatch schedules (italics added) issued to it by NS Power and any adjustments arising from schedule variances if required.

NSPI has not calculated any “impacts of variances by PHP” or in fact impacts of any “adjustments arising from schedule variances.” NSPI has calculated an Off Schedule Charge, or “penalty” for PHP deviations that is not based on cost impacts of the actual deviation. We include a recommendation regarding amounts owed by PHP for deviations from schedule (also referred to as Cause Code 5 or PDN deviations). (**Recommendation XV-2**)

As described above, the CBL Energy Charge is a fixed rate for each tariff year and is based on the forecasted incremental cost to serve a constant PHP load each hour. In practice, NSPI co-optimizes PHP load in the dispatch process, and so, actual costs are expected to be lower than forecasted because PHP load will be reduced in high-cost hours and increased in low-cost hours. This is the underlying rationale of the ADC benefit. However, as we noted previously, in order to accurately measure ADC benefits, forecasted F&PP costs (\$/MWh) and forecast loads must be reasonably accurate. If they are not, the difference between the CBL Energy Charge (based on forecasted F&PP costs and loads) and the actual cost to serve PHP (based on actual F&PP costs and loads) will not measure ADC benefits, but simply reflect the difference between forecast and actual F&PP costs (\$/MWh) and load. Thus, the measured ADC benefits in 2024 and 2025 must be viewed with skepticism since they were not corrected for this forecast error. We find that the design of the ELIADC tariff is deficient. We include a recommendation for the calculation of ADC benefits. (**Recommendation XV-3**)

XV.B.2. Active Demand Control Provisions

Under the ELIADC, NSPI can control PHP’s load within limits established under the tariff and associated protocols. Prior to the beginning of each tariff year, PHP provides NSPI a forecast of annual and monthly energy requirements. As described above, this annual forecast is used by NSPI to determine the CBL Energy Charge paid by PHP for energy consumed during the tariff year.⁸³⁵

At the beginning of each month, NSPI updates the monthly energy target and breaks it into weekly MWh targets, which are used as inputs to PortOps. PHP’s load is co-optimized as part of the overall system to solve for the least-cost constrained dispatch, which determines both Day Ahead and Intra Day schedules for PHP.

PHP load is treated like a source of ‘negative generation’ with nine distinct loading ranges based on operating modes (“OMs”) that correspond to particular mill equipment configurations. Each OM has specific operational characteristics including max/min run time, max/min downtime, pulp creation and consumption, and energy demand. Periodically, PHP provides NSPI an update to the availability of the OMs, which is then updated in PortOps. The load ranges for each of the OMs are shown in Figure XV-5.

⁸³⁵ 2024-2025 ELIADC Tariff, p. 2.

Figure XV-5: PHP Operating Modes



The Day Ahead and Intra-Day load schedules established by NSPI indicate a single load (MW) per hour, but PHP is not required to meet that schedule exactly. Rather, PHP is required to operate within the corresponding OM range. Thus PHP has the substantial flexibility to modify its load without triggering a “deviation.” Figure XV-6 shows a plot of PHP loading levels within OM 4 during the audit period. This high level of load variation is found within all OM levels except OM1.

Figure XV-6: OM 4 Actual Load, 2024-2025



Figure XV-7 below shows the number of hours of actual and scheduled PHP load in each OM level during 2024. For actual load, [REDACTED] was the most common, accounting for [REDACTED]% of the hours during 2024. [REDACTED] was next most common accounting for [REDACTED]% of hours. For scheduled load, [REDACTED] was the most common, accounting for [REDACTED]% of hours. [REDACTED] was the next most common, accounting for [REDACTED]% of hours. In 2024, scheduled load in [REDACTED] and in [REDACTED] were much higher than actual load levels, while [REDACTED] and [REDACTED] had higher actual load levels than scheduled.

Figure XV-7: Frequency of PHP Operating Modes, 2024



Figure XV-8 below shows the number of hours of actual and scheduled PHP load in each OM level during 2025. In 2025, no final intra-day schedules exist for the period from April 25 to August 5 so all data in this period has been excluded from the figure. Scheduled and actual loads are concentrated at the same OM levels. Actual load was in [REDACTED] during [REDACTED]% of total hours in 2025 and in [REDACTED] during [REDACTED]% of total hours. Scheduled load was in [REDACTED] during [REDACTED]% of total hours in 2025, in [REDACTED] during [REDACTED]% of total hours and in [REDACTED] during [REDACTED]% of total hours.

Figure XV-8: Frequency of PHP Operating Modes, 2025



The status of pulp storage at the mill is an important factor in the modelling and dispatch of PHP load. If the silo is close to full, PHP cannot be run at high load as there is no storage available for the pulp. If the silo runs dry, PHP cannot make paper. NSPI describes this as follows:

Since there is a finite amount of storage space on site at PHP this needs to be tracked and modelled. The actual storage level on the PHP site is tracked via PI data and automatically imported into PortOps. When the model dispatches PHP it considers the build/draw of pulp from the unique operating modes and its impact on the pulp storage position.⁸³⁶

Under normal operations, the Day Ahead Marketer determines the hourly schedule for PHP load on a daily basis, which is provided to PHP and to the NSPSO. Intraday adjustments to NSPI supply or PHP demand are reviewed and updated in PortOps on a continual basis. An updated hourly schedule is produced by the Real Time Marketer and also provided to PHP and to the NSPSO.⁸³⁷ Once the final hourly schedule is set, the NSPSO has the discretion to re-dispatch PHP to manage system conditions in real time. PHP has the flexibility to increase or decrease load within the OM level without triggering a cause code deviation.

⁸³⁶ 2022-2023 Bates White Audit Report, page 409.

⁸³⁷ 2022-2023 Bates White Audit Report, page 409.

Due to the cyber event, PortOps was not available for most of 2025 (April 25 through the end of the year). During the period April 25, 2025 to May 26, 2025 no Day-Ahead schedules were created. During the period from April 25, 2025 to August 5, 2025 no Intra-day schedules were created. During this time, PHP agreed to be dispatched in real-time by NSPSO. Starting May 26, 2025, Plexos was used to create or to assist in the creation of manually constructed schedules.⁸³⁸ PI data was also not available starting April 25, 2025 as PortOps was not functioning, so pulp storage levels - a critical component in the scheduling and dispatch of PHP – needed to be tracked and communicated to the marketing desk and NSPSO manually.

XV.B.3. Scheduling and ADC Benefits

Over the audit period, PHP's load (MWh) corresponded reasonably closely to the target energy (MWh) as adjusted for each month although there were several monthly outliers.⁸³⁹ Figure XV-9 compares PHP monthly adjusted target energy to actual delivered energy by month for 2024. On the whole, PHP load was approximately █% below the monthly energy targets. This result is driven by the months of August and October, where PHP load was substantially below target.

⁸³⁸ ELIADC Tariff 2025 Annual Report (NSEB M12768).

⁸³⁹ Target energy can be adjusted throughout the year. The comparison of target levels to delivered energy in this section is based on final adjusted target levels.

Figure XV-9: PHP Target Energy and Actual Load, 2024



In Figure XV-10 we compare monthly adjusted target energy and the actual delivered energy by month in 2025 as we did above for 2024, however, we add a third component – PHP target energy as determined at the beginning of the year when the CBL Energy Charge is set.⁸⁴⁰ In 2025, PHP's actual load is [REDACTED] the CBL annual [REDACTED]. One factor that played a role in [REDACTED] PHP load in 2025 was a [REDACTED] for paper products caused by [REDACTED]. There are [REDACTED] months when the annual CBL annual target was equal to the monthly adjusted target: [REDACTED]. For 2025 as a whole, PHP load was approximately [REDACTED]% [REDACTED] the monthly adjusted targets and [REDACTED]% [REDACTED] the annual CBL annual target.

⁸⁴⁰ We note that PHP's initial 2025 forecast totaled approximately [REDACTED] GWh, but the monthly requirements were regularly adjusted downward throughout the year resulting in target energy of [REDACTED] GWh. See ELIADC Tariff 2025 Annual Report (NSEB M12768).

Figure XV-10: PHP Target Energy and Actual Load, 2025⁸⁴¹

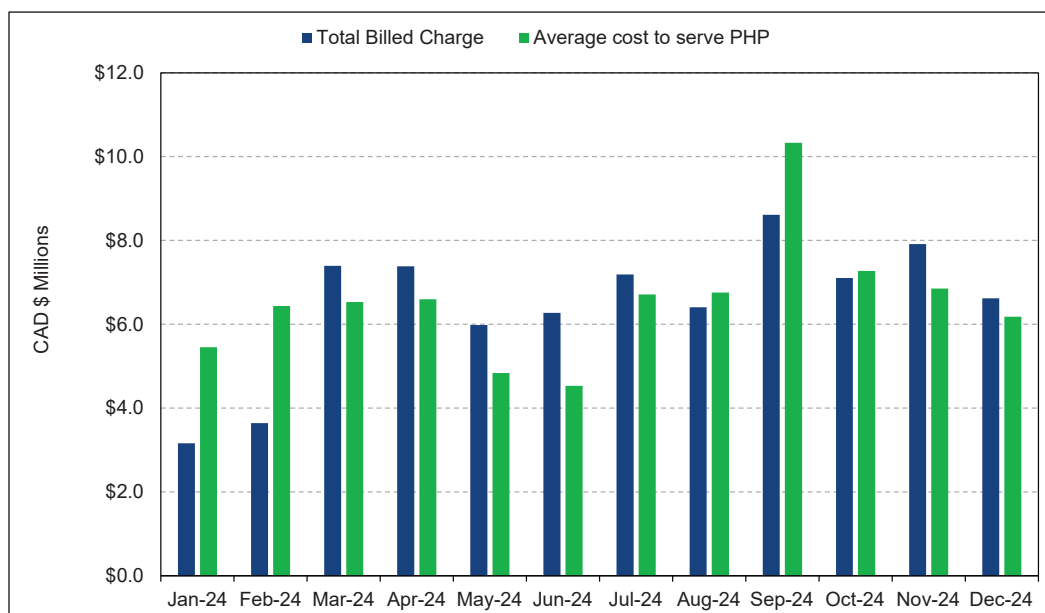


The next two figures show the difference between billed charges and actual costs in 2024 and 2025. There is a lot of variability in the monthly differences between billed and actual charges due to differences in fuel prices, monthly loads, and the hourly distribution of loads within the month. (The difference between the hourly distribution of loads within the month gives rise to ADC benefits.)

Figure XV-11 compares total charges billed to PHP each month in 2024 to the actual average cost to serve PHP load. In aggregate for 2024, billed charges to PHP totaled approximately \$77.7 million, while the actual average cost to serve load was \$78.5 million, a difference of -\$0.8 million (actual cost to serve was greater than the billed amount). This compares to a difference of -\$2.8 million in the month of February illustrating that there is a lot of monthly variance that nets out over the year.

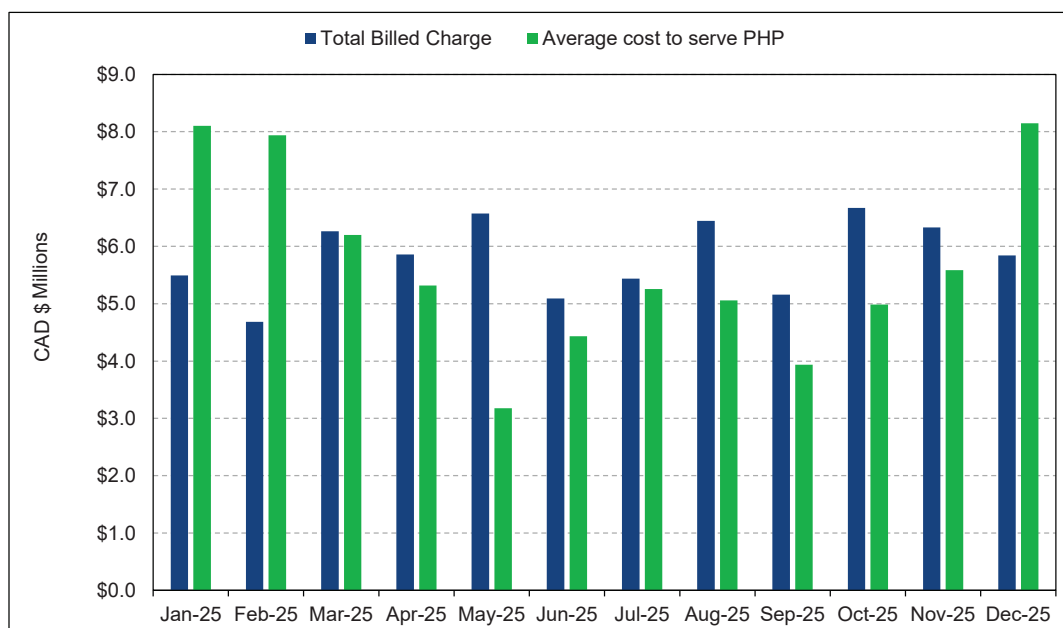
⁸⁴¹ ELIADC Tariff 2025 Annual Report (NSEB M12768).

Figure XV-11: PHP Billed Charge and Actual Average Cost to Serve, 2024



As shown in Figure XV-12 below, in 2025 billed charges to PHP totaled approximately \$69.7 million, while the actual average cost to serve load was \$68.1 million, a difference of \$1.6 million. This compares to a difference of -\$3.3 million in February and a difference of \$3.4 in May, again illustrating monthly variability.

Figure XV-12: PHP Billed Charge and Actual Average Cost to Serve, 2025



In 2025, the ADC Benefit was positive and totaled \$1,522,611. However, changes in fuel costs (\$/MWh) and monthly load can also cause positive ADC Benefits under the current calculation. Adjusting for these factors could reduce or eliminate the ADC Benefit so it must be interpreted in this light.

(Recommendation XV-3)

XV.B.4. PHP Deviations from Schedule During the Audit Period

PHP deviations from scheduled load in real time occur when PHP's actual load does not match the schedule and when actual load and scheduled loads are in different OM levels. (Changes in PHP load within an OM level are allowed.) Deviations are identified with a cause code for one of the following circumstances:

Cause Code 1: NUP – System Operator initiated ramp Up

Cause Code 2: NDN – System Operator initiated ramp Down

Cause Code 3: PFL – PHP Failure to Load due to equipment or process constraints

Cause Code 4: PNA – PHP and NSP Agreement to new dispatch

Cause Code 5: PDN – PHP Decision to vary from schedule.⁸⁴²

It takes time for PHP to respond to schedule changes. In many cases, it can take more than an hour and up to multiple hours for PHP to move between OM levels. NSPI identifies deviations as a multi-hour event, not an hourly event. So even if actual load and scheduled load are at different OM levels for multiple hours as PHP adjusts to a new schedule, NSPI identifies only one deviation and assigns it to one hour in the ramping period. To get a full picture of deviations, under NSPI's definition, actual and scheduled load must be examined on a 5-minute interval basis over multiple hours in order to identify the starting and ending points of the actual change in PHP load. An examination of deviations between scheduled and actual load on an hourly basis will show many more deviations than identified by NSPI.

XV.B.4.a. Single Week Example of ELIADC Scheduling

NSPI provided a specific example of scheduling and loads under the ELIADC for the week beginning Monday, February 3, 2025. The original monthly load target for February 2025 was █████ MWh. The weekly target set by NSPI was █████ MWh (or one quarter of the monthly adjusted target). The actual weekly load was █████ MWh. The hourly schedule, co-optimized subject to available operating modes, is shown in Figure XV-13 along with actual PHP load. The vertical lines show hours flagged by NSPI as having a load deviation. Also shown are hours that we flag as having a load deviation, that NSPI did not because NSPI does not identify deviations in ramping hours. Most deviations occurred when PHP was scheduled at level OM-8 but operated at level OM-5 or when PHP was scheduled at level OM-5 but

⁸⁴² PDN was known as PDC in 2020.

operated at level OM-2. Figure XV-13 illustrates the variability of PHP load, the frequency of deviations from schedule, and the identification of more deviations when identified at the hourly level.

Figure XV-13: Schedule and PHP Actual Load, Week of February 3, 2025



There were 76 hours with deviations as identified by NSPI during this week (45% of all hours). We identified an additional 16 deviations raising the weekly percentage to 54%. Regarding NSPI-identified deviations, over half (42 of 76) of the hours with deviations were Cause Code 3: PFL – PHP failure to load due to equipment or process constraints. Nineteen deviations were the result of redispatch agreed between PHP and NSPI (Cause Code 4: PNA) and the remaining fifteen off-schedule hours resulted from NSPSO instructions to ramp down, Cause Code 2: NDN. All of the deviations during this week in February were in the downward direction from scheduled amounts and most were related to PHP operational constraints. PHP deviations from schedule over the full audit period are discussed in more detail below.

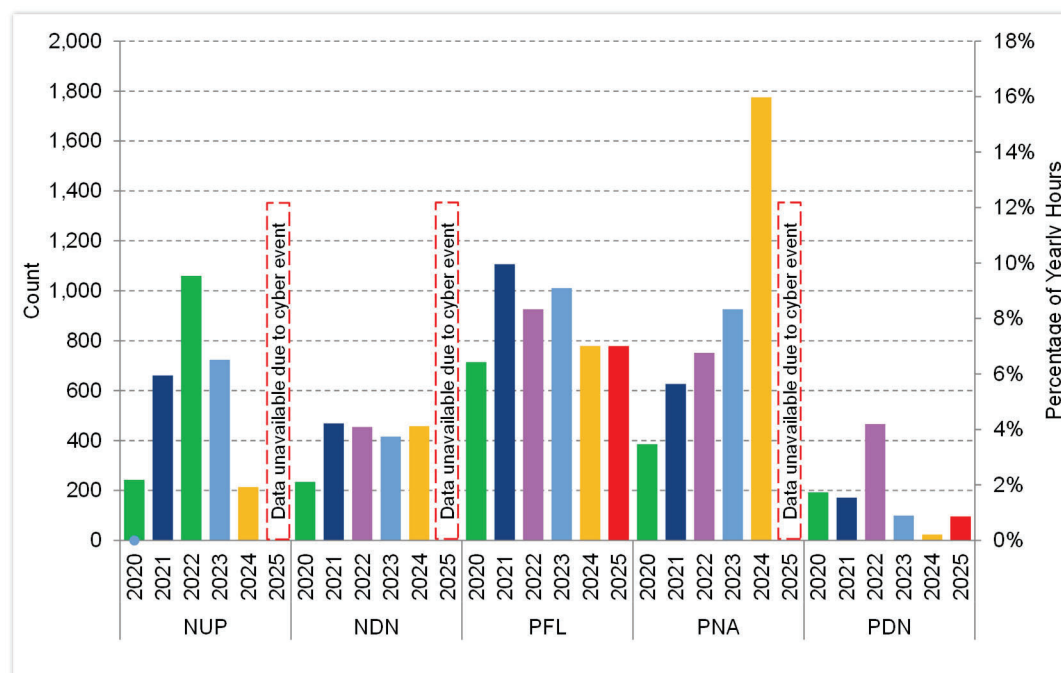
XV.B.4.b. The Number of PHP Deviations from Schedule

During the audit period, we identified [REDACTED] hours with a deviation from schedule when in the same hour NSPI did not. Also, we identified [REDACTED] hours in which we found no deviation but NSPI did find one. In total, we found deviations in [REDACTED] hours and NSPI found deviations in [REDACTED] hours. These discrepancies are due to the “ramping” issue identified above and to measurement issues. We find that

identification of PHP real-time deviations from schedule should be done on an hourly basis for accuracy and consistency with the methods used by independent system operators. **(Recommendation XV-4)**

Figure XV-14 summarizes NSPI's count of hours with a real-time deviation by cause code. Cause Code 3: PFL deviations (PHP failure to load) occurred on average over the 2020-2025 period in █ % hours per year, while Cause Code 5: PDN deviations (PHP decision to deviate from schedule) occurred on average in █ of hours per year over the same period. Cause Code 4: PNA deviations (PHP and NSP agreement to new dispatch) doubled between 2023 and 2024.

Figure XV-14: PHP Off-Schedule Deviations, Hourly Count by Cause Code 2020-2025⁸⁴³



In 2024, there was a significant reduction in NSPSO initiated deviations in the up direction (NUP) and a slight increase in NSPSO initiated deviations in the down direction (NDN). For 2025, we report no deviations in these categories, nor the PNA category, because during the cyber event these deviations were not tracked so we do not have comparable data.

XV.B.4.c. The Identification of PHP Deviations from Schedule

Under the ELIADC tariff, NS Power/NSPSO is required to track the timing, magnitude, and reason for deviations,⁸⁴⁴

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

⁸⁴³ 2022-2023 Bates White Audit Report, page 415.

⁸⁴⁴ 2024-2025 ELIADC Tariff—Schedule 1, p.5 at 11.

[Circumstances in which Variances from Scheduled Dispatch Will Be Tracked], the timing, magnitude, and reason for the deviation will be tracked and noted by NS Power/NSPSO.

During the audit period PHP – not NS Power/NSPSO – tracked deviations. While both NS Power Energy Marketing and NSPSO were aware of PHP's load relative to schedule, neither formally tracked the deviation from the hourly schedule. PHP used 5-minute demand and internal process data to identify and record deviations. On a quarterly basis, NS Power and PHP discussed the deviations. After these discussions, PHP provided their detailed deviation identification worksheet to NS Power for review.

Entrusting PHP with the responsibility of recording deviations creates a conflict of interest and is a violation of the ELIADC tariff. It is particularly problematic with respect to Cause Code 5 (PDN) - PHP Decision to vary from schedule. Deviations under Cause Code 5 result in penalties to PHP. To allow PHP to determine its own penalty hours because as NSPI has explained, "NS Power does not have access to PHP process data, or have as thorough an understanding of PHP's pulp and paper production process as PHP, both of which are required to accurately identify and code deviations from schedule" is of no avail and throws into question the validity of the identified deviations. We find that PHP should not be allowed to determine and record off-schedule deviations. We provide a recommendation regarding the recording of deviations. (**Recommendation XV-5.**)

XV.B.4.d. The Magnitude of PHP Deviations from Schedule

In prior audit reports, we reported the magnitude of deviations.⁸⁴⁵ We determined the magnitude by calculating the difference between the final intra-day (aka real-time) schedule (MW) and the actual PHP hourly load (MWh per hour). That approach, however, did not line up with the size of deviations as calculated by NSPI for two primary reasons – ramping and measurement.

Ramping: In many cases, it takes PHP more than one hour to implement a schedule change. For example, to move from OM-2 to any higher OM level (3, 4, 5, 6, 7, 8, or 9) it can take PHP up to 3 hours or more. To move from OM-3 to OM levels 4, 5, and 6 it can take 1.5 hours or more and to move from OM-3 to OM levels 7, 8, or 9 it take up to 2 hours or more. To move from OM-6 to OM levels 7, 8, or 9 it can take 1.5 hour or more. It can also take 1.5 or 2 hours for PHP to move from a current operating level to lower levels depending upon the starting and ending OM level. Cause Code deviations that occur over multiple hours are reported by NSPI to have occurred in only one hour. Thus the measurement of a deviation in over that one hour captures only part of a multi-hour deviation.

⁸⁴⁵ We asked NSPI to provide the magnitude of real-time deviations in the current and previous audit periods, but NSPI did not do so, so we calculated the magnitudes ourselves.

Measurement

- (a) PHP's final intra-day schedule is indicative of the OM level, but does not necessarily represent the actual load level at which PHP is operating. For example, the final intra-day schedule may be █ MW placing PHP in OM-8, but review of the 5-minute real-time operating data may show an operating level of █ MW (also in OM-8). A deviation will be measured by PHP with a starting point of █ MW, not the █ MW reported in the final intra-day schedule. Thus the use of the final intra-day schedule will result in measured magnitude of a deviation that is different than measured by NSPI.
- (b) Measurement misalignments also occur because PHP loading levels change within an hour, potentially every 5 minutes. Scheduled and actual PHP loads, reported on an hourly basis, are an average of the 5-minute interval load levels. Comparing averages between hourly intervals instead of comparing different load levels on a 5-minute basis as done by NSPI results in different measurements.
- (c) NSPI allows for a SCADA metering accuracy tolerance of up to 5% of actual load. This widens the band for allowable differences between actual and scheduled load that we did not incorporate into our analysis.

To be clear, PHP operating points within OM levels are highly variable and can span █ MWs or more as shown above in Figure XV-6: OM 4 Actual Load, 2024-2025. This introduces a variance between the final intra-day schedule and the operating point at which NSPI starts to measure a deviation.

We find that the size of PHP real-time deviations from schedule should be measured on an hourly basis for accuracy and consistency with the methods used by independent system operators. We provide a recommendation regarding NSPI's role in reporting off-schedule deviations. (**Recommendation XV-5**)

XV.B.4.e. Cause Code 5: PDN Deviations – PHP Decision to Vary From Schedule

NSPI identifies in its ELIADC annual reports the hours in which Cause Code 5: PDN deviations occur and the magnitude of those deviations. The cost or "penalty" for each deviation is calculated as the difference between two prices (1) the PortOps modelled forward replacement cost for PHP's actual load (\$/MWh) and (2) the CBL Energy Charge (\$/MWh) which is then multiplied by PHP's actual load.⁸⁴⁶ This calculation does not consider the size of the deviation, nor is it intended to represent the impact of the deviation on system costs. It is simply a construct used to provide an incentive for PHP to follow the scheduled dispatch, nothing more.⁸⁴⁷

⁸⁴⁶ ELIADC Tariff 2025 Annual Report (NSEB M12768).

⁸⁴⁷ ELIADC Tariff 2025 Annual Report (NSEB M12768).

In 2025, the calculated total reported penalty is \$ [REDACTED] NSPI reduced this amount by [REDACTED] % and charged PHP \$ [REDACTED] In 2024, NSPI did not charge any penalty to PHP for Cause Code 5 deviations because NSPI charges a penalty only if there is a calculated ADC benefit.

There is a small error in the calculation of the total reported penalty in 2025. In [REDACTED] hours the penalty is positive, meaning that PHP receives a credit for unilaterally deviating from schedule. In prior audit periods, positive amounts were set to zero in the Off Schedule calculations. We agree that positive amounts should be set to zero as it would not be appropriate to allow PHP to benefit from disregarding a load schedule. Setting positive amounts to zero increases the total penalty by \$ [REDACTED] to \$ [REDACTED] We recommend that this correction be made. (**Recommendation XV-6**)

In the 2025 ELIADC Annual Report, NSPI states,

In 2025 there were [REDACTED] hours in which PHP chose to deviate from the submitted schedule (Code 5, “PDN”) spread across [REDACTED] unique events (where a single event can span multiple hours). These PDN hours comprised [REDACTED] percent of PHP’s hours in 2025. *The impact on system costs of these off-schedule hours has been calculated to be \$ [REDACTED]* (italics added), of which [REDACTED] percent would have been to the benefit of NS Power’s other customers. In accordance with the ELIADC Tariff, the ADC credit payment to PHP has been reduced by this amount of \$ [REDACTED] which is shown as the “Off Schedule Charge” to PHP in the Benefit Breakdown tab of the attached Partially Confidential Annual Report.

NSPI’s statement that the penalty of \$ [REDACTED] reflects the “impact on system costs” directly contradicts NSPI’s representation in the ELIADC annual report proceeding NSEB M12768 where NSPI states,

The Off-Schedule Charge is neither a cost to customers nor a true foregone benefit. Similar to the ADC Load Shifting Differential, it is a construct of the ELIADC Tariff, where the Off-Schedule Charge was designed as an incentive for PHP to follow dispatch.

Also, the calculation of the penalty itself is not based on a change in output (i.e., a deviation) but on a price change at actual metered load.⁸⁴⁸ As we explain in Section XV.B.7, individual hours or transactions do not have costs or benefits in the context of ADC benefits.

NSPI has reduced the deviation penalty charged to PHP by [REDACTED] %. This is not supported by the ELIADC tariff nor that we are aware, any other governing document. The reduction in penalty is not reasonable since it weakens the incentive for PHP to maintain its schedule and has nothing to do with the ADC benefits calculation. Although the system impact of PHP unilateral schedule deviations are not known, unilateral deviations can decrease system reliability and create balancing costs. Also, the [REDACTED] % reduction equal to [REDACTED] % of \$ [REDACTED] or \$ [REDACTED] deprives FAM customers of revenues that it would

⁸⁴⁸ ELIADC Tariff 2025 Annual Report (NSEB M12768).

otherwise receive. We find that a ■% reduction in the Cause Code 5 penalty is not warranted. We include a recommendation on Cause Code 5 penalties. (**Recommendation XV-2**)

XV.B.5. Co-optimization Benefits of ADC

The core of ADC benefits arises from the ability of NSP to schedule and dispatch PHP load across the year, both on a daily and seasonal basis, to reduce demand in high-cost periods and increase demand in low-cost periods. Similarly, PHP load can also be used on the supply side. PHP load can be scheduled and dispatched at increased levels during periods of high wind output when costs are typically low, and at reduced levels in periods of low wind output when costs are typically higher. In the next sections we examine the dispatch of PHP during periods of high and low FAM load and wind output to evaluate the co-optimization benefits of ADC.

XV.B.5.a. Comparison of FAM and PHP Load

Co-optimization of PHP load and NSPI generation should allow for PHP load to be reduced when FAM load is high and system conditions are relatively tight, and to increase PHP load when FAM load is low, while still meeting load targets for PHP in aggregate. Figure XV-15 compares the 14-day average hourly load for FAM customers (on the left axis) and of PHP load (on the right axis). The visual comparison provided by the figure suggests that this was achieved on a modest basis – e.g., PHP load was relatively low during the 2024-2025 winter peak for FAM load.

Figure XV-15: FAM Load and PHP Load, 14-day Hourly Rolling Average, 2024-2025



This modest inverse relationship shown in Figure XV-15 is confirmed statistically, as the two data series have a correlation of -0.28 over the audit period. As a statistical measure, correlation coefficient ranges from a high of positive one, indicating data series that move proportionately exactly in step, to a low of negative 1, indicating a perfect inverse relationship. A correlation of -0.28 indicates a modest inverse relationship between FAM load and PHP load. However, if we limit our comparison to the winter months of December through March, we find a strong inverse correlation of -0.74 indicating that co-optimization of PHP in this period is beneficial. For the remaining months of April through November, the correlation is 0.21, meaning no finding of benefits can be made for this period using this methodology. In summary, we find that there is evidence of seasonal benefits of ADC in the winter months.

Figure XV-16 shows average hourly load for FAM and PHP by month for on-peak and off-peak periods in 2024.⁸⁴⁹ It indicates that PHP load was smaller relative to FAM load in peak periods than in off-peak periods. In on-peak periods PHP load averaged around [REDACTED] of system whereas in off-peak periods, PHP load was significantly higher averaging approximately [REDACTED] of system average load.

⁸⁴⁹ Peak load is defined as the monthly average load of the 16 hours from HR 7 to HR 22, seven days a week. Off-peak load is defined as the average of all remaining hours in the month.

Figure XV-16: FAM and PHP Average On-Peak and Off-Peak Load by Month, 2024



Figure XV-17 shows average hourly load for FAM and PHP by month for on-peak and off-peak periods in 2025.⁸⁵⁰ The results are similar to 2024, with the average PHP on-peak load at ■ MW and off-peak load at ■ MW. In peak periods, PHP load is a smaller portion of FAM load (averaging ■%) relative to off-peak periods where PHP is a larger portion of FAM load (averaging ■%).

⁸⁵⁰ Peak load is defined as the monthly average load of the 16 hours from HR 7 to HR 22, seven days a week. Off-peak load is defined as the average of all remaining hours in the month.

Figure XV-17: FAM and PHP Average Off-Peak Load by Month, 2025



We find that on-peak and off-peak PHP load patterns are consistent with daily co-optimization under the ELIADC, where PHP load would be backed down during high demand hours and shifted to hours of low demand when system costs are lower.

XV.B.5.b. Comparison of Wind Generation and PHP Load

Figure XV-18 provides a comparison over the audit period of 14-day average hourly PHP load and system wind generation. Under ELIADC co-optimization, the expected relationship between these series would be positive: there should be beneficial opportunities to dispatch PHP load up during high wind conditions, both to take advantage of low cost wind resources for PHP's benefit, and potentially to reduce curtailment of wind generation. In the 2022-2023 Audit Period we found no discernable relationship. In the current audit period, PHP load had a very small positive correlation with wind generation of 0.14 in the period from April 25, 2025 to the end of the audit period.⁸⁵¹ Similar to our findings in the prior audit period, we do not find ADC benefits attributable to scheduling and dispatching PHP up in times of high wind and down in periods of low wind.

⁸⁵¹ Due to data lost in the cyber event, wind generation data is available only for this limited period.

Figure XV-18: PHP Load and System Wind Generation, 14-day Hourly Rolling Average, 2024-2025



XV.B.6. Interruption

PHP was not interrupted under the ELIADC tariff during the Audit Period. During capacity scarcity events, the order of interruption for NSPI's non-firm customers is specified in the ELIADC tariff:⁸⁵²

1. Generation Replacement and Load Following (GRLF) Tariff
2. Extra Large Industrial Active Demand Control (ELIADC) Tariff
3. Shore Power Tariff
4. Interruptible Rider to the Large Industrial (LIIR)Tariff

As PHP load is dispatched based on co-optimization of the NSPI system, PHP is typically dispatched down to minimum load during tight supply events. During the audit period, no load was subscribed under the GRLF Tariff and no Shore Power or LLIR – Telemetry & Control load was interrupted. LLIR – *Non*-Telemetry & Control customers were interrupted on 10 occasions during the audit period. The lack of interruptions under the ELIADC tariff is due to the ADC and cooperative nature of that tariff.

⁸⁵² 2024-2025 ELIADC Tariff, p. 6.

XV.B.7. Bates White's 2022-2023 Audit Recommendations

In our report for the prior audit period, we made three recommendations related to the ELIADC benefits calculation, the CBL Energy Charge, and annual reporting.

Recommendation XV-1: 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.

Core ADC benefits arise from scheduling and dispatch of PHP load in lower cost hours during the year as compared to a flat baseline load. ADC benefits are calculated as the difference between the actual cost (\$/MWh) and a fixed rate for all hours – where the differences between actual costs and the fixed rate are multiplied by the hourly quantities (which results in both positive and negative amounts) and netted over the year. Individual hours or transactions do not have costs or benefits in this context. For example, it would not be correct to conclude that there is a dis-benefit in an hour where actual costs are greater than the fixed rate.

A potential secondary benefit of active demand control arises from real-time load shifting. However, the costs and benefits of real-time load shifting are hard to measure. First, real time load shifting can be done for reliability, not economic reasons. For example, the System Operator may initiate a decrease in PHP load to increase the operating reserve margin. In this case, calculating the impact on system costs would not be appropriate. Second, deviations under Cause Code 3: PFL (PHP failure to load) or Cause Code 5 PDN (PHP decision to deviate from schedule) would decrease marginal costs but should not be considered a “benefit” of ADC. PHP not operating when scheduled could result in an inefficient commitment and deviations from schedule can reduce system reliability – these costs are hard to measure. Other types of deviations are amenable to measurement. A price could be determined for a System Operator initiated ramp up (Cause Code 1 NUP) and ramp down (Cause Code 2 NDN), for example.

Regardless of the type of deviation, NSPI states that it does not have the tools to measure deviations. NSPI states that the PortOps software is unable to quantify hourly costs and benefits associated with individual cause codes deviations for numerous reasons:

- i. Load levels associated with each deviation would be too low for PortOp's precision tolerance,
- ii. Implementation of but-for scenarios may not be possible due to the inability of the PortOps model to converge,
- iii. Calculation of costs/benefits would be highly dependent on assumptions, if load rebalancing post deviation is required for the analysis,
- iv. Costs associated with the initial dispatch up cannot be reliably isolated, as the specific drivers of the NSPSO decision are not fully observable after-the-fact,

- v. Cases where dispatch down avoids customer interruptions, no comparable counterfactual solution exists, as PortOps may not converge under conditions representing unserved energy and,
- vi. Since PortOps uses forward replacement costs, while PHP is billed on actual accounting costs, the associated costs and benefits by cause code are impossible to compare directly.⁸⁵³

Regarding (vi) we disagree that a comparison to actual accounting costs is necessary because the cost and benefits of deviations are separate and distinct from the core ADC benefit calculation. Regarding the capability of PortOps to calculate the costs and benefits of real-time deviations after-the-fact, we take no position. However, we find that the source of the problem is not PortOp's limitations, but the failure of the NSPSO to log deviations, both the type and reason, in the first instance. Were this information available, together with contemporaneous real-time information such as changes in system lambda, costs and benefits might be determined by the SO without the need to run PortOps after-the-fact. We find that NSPI has attempted to satisfy 2022-2023 Audit Recommendation XV-1, but has determined it cannot. We accept NSPI's explanation that it has been unable to develop a reliable methodology to quantify the costs and benefits associated with individual cause code deviations. Due to the lack of quantification, we find that no load shifting benefits have been established for real-time ADC and that real time load deviations could have resulted in net costs. We include a recommendation regarding these findings.

(Recommendation XV-8)

Recommendation XV-2: The calculation of the CBL Energy Charge, which includes fixed costs, appears to conflict with the language of the ELIADC tariff. NSPI should either revise the calculation of the CBL Energy charge to remove the fixed cost component or revise the definition of the CBL Energy Charge in the ELIADC tariff to allow the inclusion of a fixed component.

NSPI has complied with this recommendation. The revised ELIADC tariff, approved on December 8, 2025, transfers the fixed cost recovery in the CBL Energy Charge to the CBLA. We find that NSPI has complied with this recommendation.

Recommendation XV-3: We recommend that NSPI further improve its annual reporting by including more detailed quantification of actual load shifting benefits (and costs), an identification and discussion of the types of deviations that provide the most benefits and why, ways to improve the tariff or tariff administration, and a comparison of current year outcomes to prior years to help evaluate ELIADC performance over time.

The following Figure XV-19 lists types of information that we have recommended be included in NSPI's ELIADC annual reports in prior audits and NSPI's compliance with those recommendations.

⁸⁵³ 2025 ELIADC Annual Report, p. 7-8; ELIADC Tariff 2025 Annual Report.

Figure XV-19: Deficiencies in NSPI's Reported Information

Requested Information	Provided in 2024 ELIADC Annual Report	Provided in 2025 ELIADC Annual Report
2022-2023 FAM Audit – Recommendation XV-3		
More detailed quantification of actual load shifting benefits (and costs)	No	No
An identification and discussion of the types of deviations that provide the most benefits and why	No	No
Ways to improve the tariff or tariff administration	No	No ⁸⁵⁴
A comparison of current year outcomes to prior years to help evaluate ELIADC performance over time	Yes	Yes
2020-2021 FAM Audit – Recommendation XVI-1		
Additional narrative content	Yes	Yes
Experience in administering the ELIADC during the given tariff year	Partially, noted lag in CBL Energy Charge adjustment	No, there is no discussion of the impact of the cyber event on tariff administration
Circumstances on the system that affected costs	Partially, addressed winter event	No
Causes, trends, and cost impacts associated with PHP's load deviations, particularly with respect to PFL schedule deviations	Partially, addressed trends	Partially, addressed trends, and with respect to PFL deviations, causes and trends.

NSPI has partially complied with 2022-2023 Recommendation XV-3 and 2020-2021 Recommendation XVI-1. NSPI did not provide a more detailed quantification of actual load shifting benefits. As addressed in our response to 2022-2023 Recommendation XV-1 above, NSPI is not able to quantify the benefits or costs of real-time load shifting. Regarding core load-shifting benefits resulting from adjustments to daily and seasonal schedules, NSPI continues to work on improved quantification methods.⁸⁵⁵ With respect to the remaining recommendations in the prior audit, NSPI did not provide a narrative discussion of the most beneficial deviations, or offer ways to improve the tariff or tariff administration and continues to provide incomplete information as outlined in the 2020-2021 audit. We find that the ELIADC annual reports continue to lack information needed to give FAM customers an objective overview of the pros and cons of the ELIADC tariff and a path for its improvement. We provide a recommendation on this point. **(Recommendation XV-9)**

⁸⁵⁴ NSPI has noted in prior annual reports, that changing fuel prices relative to the forecast price embedded in the CBL Energy Charge distort the calculated ADC Load Shifting Differential. In the 2025 ELIADC Annual Report NSPI states that “the relatively stable fuel pricing as compared to what was used in the CBL forecast...contributed to a positive ADC Load Shifting Differential for 2025” (p. 3) without noting that calculated ADC benefit could be due to changing fuel prices and not load shifting. Moreover, NSPI has proposed no change in the ELIADC tariff to correct this distortion.

⁸⁵⁵ NS Power presented analytical work on a new methodology for calculating ADC benefits to FAM SWG at the Q2 2026 meeting.

XV.C. Conclusions

Conclusion XV-1: The ELIADC tariff, as shown by benefits reported in the ELIADC annual reports, has minimally achieved the intent of the Board during the Audit Period. FAM customers did not bear the average costs to serve PHP load, and PHP made the minimum required contribution to fixed costs.

Conclusion XV-2: ELIADC benefits as reported in the ELIADC annual reports are largely composed of the mandatory contribution to fixed costs. **(Recommendation XV-1)**

Conclusion XV-3: PHP load levels vary significantly within OM levels.

Conclusion XV-4: ADC benefits are calculated as the difference between annual forecasted incremental fuel costs (based on forecast load), and actual annual weighted average fuel costs (based on actual load). Changes in fuel prices and load from forecast amounts will distort the ADC benefit calculation which can result in no ADC benefits when they do exist, or positive ADC benefits when they do not. The design of the ADC benefits calculation is deficient. **(Recommendation XV-3)**

Conclusion XV-5: NSPI identifies real-time schedule deviations by the event, not the hour. If actual load and scheduled load are at different OM levels for multiple hours as PHP adjusts to a real time change in schedule, NSPI identifies only one deviation and assigns it to one hour. **(Recommendation XV-4)**

Conclusion XV-6: Identifying deviations on an hourly basis will result in the identification of many more real-time PHP deviations from scheduled load than currently reported. **(Recommendation XV-4)**

Conclusion XV-7: NSPI measures the size of real-time schedule deviations by event, not the hour. **(Recommendation XV-5)**

Conclusion XV-8: PHP determines and records off-schedule deviations, not NSPI or NSPSO, in violation of the ELIADC tariff. **(Recommendation XV-7)**

Conclusion XV-9: There is no basis to reduce the penalty charged to PHP for Cause Code 5 PDN deviations (PHP decision to vary from schedule) by █%, an amount equal to \$█. **(Recommendation XV-2)**

Conclusion XV-10: In 2025, positive amounts were included in the calculation of the Cause Code 5 PDN cost penalty resulting in a credit of \$█ for unilaterally deviating from schedule in four hours. In prior audit period calculations positive amounts were set to zero. **(Recommendation XV-6)**

Conclusion XV-11: There is evidence of seasonal co-optimization benefits of FAM and PHP load under the ELIADC in the winter months.

Conclusion XV-12: PHP load patterns that show lower levels of PHP load during system peak load hours and higher PHP load during system off-peak hours consistent with daily co-optimization of PHP and FAM loads under the ELIADC.

Conclusion XV-13: We have found no evidence in the current audit period of ADC benefits associated with managing wind generation or co-optimizing wind generation and PHP load. Limited data availability due to the cyber event may have contributed to this finding.

Conclusion XV-14: PHP was not interrupted under a capacity scarcity event as specified in the ELIADC tariff during the audit period due to the ADC and cooperative nature of that tariff

Conclusion XV-15: No load shifting benefits have been established for real-time active demand control. Real-time load deviations could have resulted in net costs. **(Recommendation XV-8)**

Conclusion XV-16: ELIADC annual reports continue to lack information needed to give FAM customers an objective overview of the pros and cons of the ELIADC tariff and a path for its improvement. **(Recommendation XV-9)**

XV.D. Recommendations

Recommendation XV-1: In the 2026 ELIADC annual report and all future reports, NSPI should report the amounts collected under the \$4/MWh (or any other) mandatory contribution to fixed costs, but should not characterize this cost recovery as a benefit to FAM customers.

Recommendation XV-2: We recommend that PHP be required to pay an additional \$ [REDACTED] for Cause Code 5 penalties in 2025 and that these amounts be allocated to FAM customers.

Recommendation XV-3: To the extent possible, the calculation of ADC benefits should be modified to account for changes between forecast and actual fuel prices and forecast and actual loads starting in 2026.

Recommendation XV-4: Real-time PHP deviations from schedule should be identified on an hourly basis starting in 2026 and reported in the 2026 ELIADC annual report and any future reports.

Recommendation XV-5: The size of real-time PHP deviations should be measured by hour, as opposed to event, starting in 2026 and reported in the 2026 ELIADC annual report and any future reports.

Recommendation XV-6: NSPI should correct the calculation of off-schedule costs associated with Cause Code 5: PDN violations in the 2025 ELIADC Annual Report, to remove positive values, increasing the total cost by \$ [REDACTED] to \$ [REDACTED]

Recommendation XV-7: The NSPSO or successor SO should be required to identify and record PHP real-time deviations from schedule, and the reason for each deviation using verifiable information from PHP.

Recommendation XV-8: NSPI should investigate other methods of pricing deviations in real time for PHP such as paying PHP for responding to a request by the SO to change OM level in real time and charging PHP when it deviates from its OM level in real time.

Recommendation XV-9: The Board should include the determination of reporting requirements as part of the proceeding to determine the successor tariff to the ELIADC.