

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

NON-CONFIDENTIAL

1 **Request IR-1:**

2
3 **Please file a copy of the consensus agreement reached with customer representatives.**

4
5 Response IR-1:

6
7 Please refer to Attachment 1.

Nova Scotia Energy Board

IN THE MATTER OF A GENERAL RATE APPLICATION by NOVA SCOTIA POWER
INCORPORATED for approval of certain revisions to its Rates, Charges, and Regulations

Settlement Agreement

WHEREAS

- A. Nova Scotia Power (“NS Power”), along with the Consumer Advocate (“CA”), Small Business Advocate (“SBA”), counsel for the Industrial Group, representing CKF Inc., Crown Fibre Tube Inc., Irving Shipbuilding Inc., K + S Windsor Salt Ltd., Maritime Paper Products Ltd., Michelin North America (Canada) Inc., Compass Minerals Canada Corp., Farnell Packaging Ltd., P & H Milling Group, and PSA Halifax (“IG”), counsel for the Berwick Electric Commission, Riverport Electric Light Commission, the Town of Mahone Bay, and the Town of Antigonish (Municipal Electric Utilities or “MEUs”), and counsel for Port Hawkesbury Paper (“PHP”) (collectively, the “Customer Representatives”, who along with NS Power are referred to herein as the “Parties”) have engaged in a collaborative process to reach consensus on a 2026-2027 General Rate Application (“GRA”).
- B. This collaborative process included multiple meetings and the sharing of information that led to NS Power providing the Customer Representatives with a proposed 2026-2027 GRA on April 25, 2025 (“Draft GRA”).
- C. On May 27, 2025, Customer Representatives were then provided with all Draft GRA supporting documentation, including standardized filings.
- D. Following the provision of these materials, the Parties participated in two rounds of information requests, multiple technical conferences, and three full days of settlement meetings.
- E. Throughout the process described in the foregoing, Customer Representatives were aided by their respective expert consultants, as each deemed necessary or appropriate.
- F. The Parties desire to resolve the 2026-2027 GRA on the terms set out herein.

NOW THEREFORE, the Parties agree as follows:

1. The Parties have reached agreement on the outcomes that will result from the 2026-2027 GRA as represented by the terms set out in Schedule “A” attached hereto (“Settlement Agreement”). The Parties acknowledge NS Power will be filing its 2026-2027 GRA in all other respects consistent with the Draft GRA.
2. NS Power will file the 2026-2027 GRA with the Nova Scotia Energy Board (“Board” or “NSEB”) in a manner consistent with this Settlement Agreement. The Customer Representatives reserve the right to ask Information Requests and file evidence in the event the filed 2026-2027 GRA application is inconsistent with this Settlement Agreement.
3. Prior to filing the 2026-2027 GRA with the Board, NS Power will file a letter with the Board, notifying it of the forthcoming 2026-2027 GRA. The letter will include an overview of the collaborative process that the Parties have undertaken and a mutually agreed-upon expression of their support for the outcomes of the 2026-2027 GRA (“Pre-GRA Letter”).
4. The 2026-2027 GRA will include an overview of the collaborative process that the Parties have undertaken and a mutually agreed-upon expression of their support for the outcomes of the 2026-2027 GRA. If requested by the Board, the Customer Representatives will also provide their own written expression of their support for the outcomes of the 2026-2027 GRA.
5. The Parties understand that time is of the essence, and they will use reasonable efforts to facilitate the filing of both the Pre-GRA Letter and the 2026-2027 GRA in a timely manner.
6. The Parties agree to the terms set out in Schedule “A” to resolve the matters at issue for the 2026-2027 GRA and without prejudice to any position that may be taken by any Party in any future regulatory proceeding.
7. This Settlement Agreement may be executed by the Parties in counterparts, each of which when so executed and delivered shall be deemed to be an original and when taken together shall be deemed to be one and the same instrument. The electronic delivery, including, without limitation, by email, of any signed original of this Settlement Agreement shall be the same as the delivery of an original.

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE



Per: David Roberts and Michael Murphy

SMALL BUSINESS ADVOCATE

Per:

INDUSTRIAL GROUP

Per:

NOVA SCOTIA POWER INC.

Per:

PORT HAWKESBURY PAPER LP

Per:

MUNICIPAL ELECTRIC UTILITIES

Per:

2026-2027 General Rate Application Settlement Agreement

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE

SMALL BUSINESS ADVOCATE

Per:


Per: MELISSA P. MACADAM

INDUSTRIAL GROUP

NOVA SCOTIA POWER INC.

Per:

Per:

PORT HAWKESBURY PAPER LP

MUNICIPAL ELECTRIC UTILITIES

Per:

Per:

All of which is hereby agreed to by the Parties effective as of the 29th day of August, 2025.

CONSUMER ADVOCATE

SMALL BUSINESS ADVOCATE

Per:

Per:

INDUSTRIAL GROUP

NOVA SCOTIA POWER INC.



Per: Nancy G. Rubin, K.C.

Per:

PORT HAWKESBURY PAPER LP

MUNICIPAL ELECTRIC UTILITIES

Per:

Per:

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE

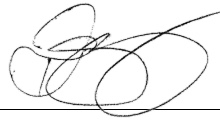
SMALL BUSINESS ADVOCATE

Per:

Per:

INDUSTRIAL GROUP

NOVA SCOTIA POWER INC.



Per:

Per: Peter Gregg
President and CEO

PORT HAWKESBURY PAPER LP

MUNICIPAL ELECTRIC UTILITIES

Per:

Per:

2026-2027 General Rate Application Settlement Agreement

All of which is hereby agreed to by the Parties effective as of the 29 day of August, 2025.

CONSUMER ADVOCATE

SMALL BUSINESS ADVOCATE

Per:

Per:

INDUSTRIAL GROUP

NOVA SCOTIA POWER INC.

Per:

Per:

PORT HAWKESBURY PAPER LP

MUNICIPAL ELECTRIC UTILITIES

Brian Lock
Per: Brian Lock

Per:

2026-2027 General Rate Application Settlement Agreement

All of which is hereby agreed to by the Parties effective as of the 21st day of August, 2025.

CONSUMER ADVOCATE

SMALL BUSINESS ADVOCATE

Per:

Per:

INDUSTRIAL GROUP

NOVA SCOTIA POWER INC.

Per:

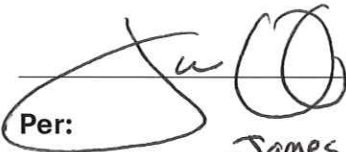
Per:

PORT HAWKESBURY PAPER LP

MUNICIPAL ELECTRIC UTILITIES

Per:

Per:


James MacDuff

Schedule “A”

Terms of Settlement

It is acknowledged that, subject to Board approvals, rate increases other than those identified herein may occur prior to the effective date of the next general rate application in the form of Board-approved riders. Recognizing the forecast impacts of the 2026 FAM AA/BA for the Large and Medium Industrial Classes, NS Power will support efforts in the 2026 FAM AA/BA proceeding to smooth or mitigate the overall impact of rate changes for the 2026-2027 test period.

GRA Element	Settlement Terms
Rates	a) Rates are proposed to be effective January 1, 2026 and the Parties will make all reasonable efforts to facilitate and support a process that will result in this outcome. b) Subject to the terms set out herein being fully incorporated into the 2026-2027 GRA, the average rate increase across all customer classes (inclusive of non-fuel and Base Cost of Fuel costs) is anticipated to be approximately 2.1% in 2026 and 2.1% in 2027.
Depreciation	a) The Parties agree to reduce depreciation rates in accordance with Appendix “A” in order to achieve a reduction in depreciation and accretion expense of approximately \$20M/year over the 2026-2027 test period, as compared to the depreciation rates included in the Draft GRA.
O&M	a) The Parties agree to the operation and maintenance expense amounts included in the Draft GRA, subject to the reductions in O&M set out in the attached Appendix “B”.
Storm Cost Recovery Rider	a) The Storm Cost Recovery Rider will be implemented as described in the Draft GRA, subject to the following: (a) the Storm Cost Recovery Rider will not be implemented on a permanent basis as proposed, rather it will continue on a pilot basis with costs in 2026 and 2027 eligible for the rider; and (b) the threshold for making an application to return an

2026-2027 General Rate Application Settlement Agreement

GRA Element	Settlement Terms
	underspend to customers will be changed from \$5 million to \$2.5 million.
Cost of Capital and Earnings Band	a) An overall return on equity of 9% for rate setting purposes retained, as well as an earnings band of 8.75% to 9.25%.
Capital Structure	a) An equity thickness of 40% for rate setting purposes will be retained.
DSM Rider	a) The DSM Rider will be amended as set out in Appendix “C”. NS Power will make best efforts to negotiate necessary revisions to its Supply Agreement with EfficiencyOne, if any, or otherwise bring such revisions forward in the relevant proceeding to ensure that the End of Approved DSM Term Adjustment is implemented for the 2023-2026 term.
Weather Normalization Mechanism	a) The request for approval of a Weather Normalization Mechanism will be removed; however, the parties agree to participate in an information session to gain a better understanding of Weather Normalization Mechanisms.
Cost of Service (“COS”)	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.
MEU Treatment	a) The MEUs will be included as taking service under the Municipal Tariff in calculating the Municipal Tariff rates for the 2026-2027 GRA and the MEUs commit to taking partial service under the Municipal Tariff in the years 2026 and 2027 .

2026-2027 General Rate Application Settlement Agreement

GRA Element	Settlement Terms
	b) NS Power and the MEUs will work collaboratively and in good faith to determine and attempt to agree, by no later than December 1, 2025 on (1) the timeline by which the MEUs will pay NS Power the full amounts of outstanding fuel costs and Maritime Link Assessment costs, and (2) the implementation of the BUTU Tariff service arrangements in conjunction with service under the Municipal Tariff in 2025, 2026, and 2027.
OATT	a) In calculating the OATT rate, NS Power will cap the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service. b) The 2-standard deviation methodology will be used for ratemaking purposes for the load following requirement. c) For the 2026-2027 GRA period, the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis.
PHP Treatment	a) NS Power's 2026/2027 cost of service study includes PHP as an above-the-line customer based on the forecast of receiving Board approvals for a new PHP tariff in time to implement for January 1, 2026. b) The COS has been prepared on the basis of the following PHP load characteristics: a) PHP's firm load at 8MW at the three coincident peaks; b) PHP's firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP metered load at the time of NSP's 3CP; and c) PHP energy will be based on PHP's forecast usage for the test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm. The same load characteristics are applicable to the base cost of fuel model as well. c) The dollar value of the Interruptible credit to be applicable to PHP's interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit. d) PHP and NS Power will complete discussions and analysis of the value of Active Demand Control ("ADC"), which shall be proposed to be a rider to the cost-based rate. The value of ADC, and the proposal for cost recovery, if any, shall be

2026-2027 General Rate Application Settlement Agreement

GRA Element	Settlement Terms
	brought forward for approval by the Board later this year to be effective January 1, 2026. For clarity, any payment approved by the Board for Active Demand Control services will be collected from above the line customers. e) NS Power and PHP shall reflect the foregoing in a written tariff which shall also include a proposal for priority interruptibility to be brought forward for approval by the Board later this year to be effective January 1, 2026 and PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes. f) In the PHP ADC and tariff processes that will be brought forward for approval by the Board later this year, it remains open for all Parties to take any position they so choose, including whether each of the PHP ADC and tariff filing(s) is inconsistent with the load characteristics and basic tariff structure as set out above. g) NS Power may seek Board approval for a deferral account to account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers: (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA; (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.
Securitization	a) NS Power will make best efforts to finalize and apply prior to January 1, 2026 for approval of its proposed securitization of assets, cost of service treatment and the Securitization Rider. It remains open for all Parties to take any position they so choose in relation to such an application.
ML Transmission Assets	a) Inclusion of CI 43324, CI 43678, CI 45066, and CI 45067 in rate base, subject to the Board being satisfied that the threshold test it articulated in paragraph 405 of its decision in M10431 has been met.

2026-2027 General Rate Application Settlement Agreement

GRA Element	Settlement Terms
EIFEL	a) If the excessive interest and financing expenses limitation (“EIFEL”) exemption is not enacted, the Parties agree to defer the incremental tax expense over the 2026-2027 GRA period, which is anticipated to be approximately \$7.5 million.
NS Power Future Deliverables	a) Within a reasonable amount of time following the execution of this Settlement Agreement, NS Power will provide: (a) confirmation that radial to generation lines being allocated to the generation function do not also serve any load; and (b) the methodology that NS Power is proposing to functionalize storage assets.

2026-2027 General Rate Application Settlement Agreement

Appendix "A"

Appendix "A"										
NOVA SCOTIA POWER, INC.										
TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2023										
DEPRECIABLE GROUP (1)	PROBABLE RETIREMENT DATE (2)	ESTIMATED SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2023 (5)	BOOK RESERVE AS OF DECEMBER 31, 2023 (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)	
DEPRECIABLE PLANT										
310.99 STEAM PRODUCTION PLANT										
LINGAN										
LINGAN 1	12-2049	65 - L1 a	(10)	138,151,529	103,751,275	48,215,407	2,234,591	1.62	21.6	
LINGAN 2	12-2029	65 - L1 a	(10)	86,836,521	100,062,274	(4,542,101)	-	-	-	
LINGAN 3-4	12-2049	65 - L1 a	(10)	290,616,704	171,721,364	147,957,010	7,037,590	2.42	21.0	
LINGAN - COMMON	12-2049	65 - L1 a	(10)	137,819,664	31,467,217	120,134,413	5,459,756	3.96	22.0	
TOTAL LINGAN				653,424,418	407,002,131	311,764,729	14,731,937	2.25		
POINT ACONI	12-2029	65 - L1 a	(5)	574,355,237	243,710,224	359,362,775	62,112,977	10.81	5.8	
POINT TUPPER	12-2048	65 - L1 a	(8)	204,646,401	93,394,889	127,623,224	6,198,266	3.03	20.6	
TRENTON										
TRENTON 5	12-2029	65 - L1 a	(4)	154,246,212	69,420,216	90,995,844	15,520,279	10.06	5.9	
TRENTON 6	12-2029	65 - L1 a	(4)	287,095,316	131,910,745	166,668,384	29,020,962	10.11	5.7	
TRENTON - COMMON	12-2029	65 - L1 a	(4)	68,919,523	11,056,285	60,620,018	10,263,264	14.89	5.9	
TOTAL TRENTON				510,261,050	212,387,246	318,284,246	54,804,505	10.74		
TUFTS COVE										
TUFTS COVE 1	12-2049	65 - L1 a	(5)	51,886,621	32,885,132	21,596,030	969,279	1.87	22.3	
TUFTS COVE 2	12-2049	65 - L1 a	(5)	58,767,019	26,896,529	34,808,842	1,578,906	2.69	22.0	
TUFTS COVE 3	12-2049	65 - L1 a	(5)	90,099,433	40,234,912	54,369,492	2,508,142	2.78	21.7	
TUFTS COVE 6	12-2049	65 - L1 a	(5)	99,805,461	34,254,208	70,541,526	3,193,342	3.20	22.1	
TUFTS COVE - COMMON	12-2049	65 - L1 a	(5)	102,844,873	39,733,086	68,254,030	3,134,100	3.05	21.8	
TOTAL TUFTS COVE				403,403,608	174,003,666	249,569,920	11,383,769	2.82		
POINT TUPPER MARINE TERMINAL	12-2029	100 - R1 a	(15)	35,156,805	18,934,839	21,495,487	3,618,881	10.29	5.9	
PORT HAWKESBURY BIOMASS	12-2045	65 - L1 a	(4)	212,173,030	40,969,204	179,690,747	9,220,034	4.35	19.5	
INTERNATIONAL COAL PIER	12-2029	65 - L1 a	(154)	11,628,782	(5,594,604)	35,131,711	5,930,262	51.00	5.9	
GENERAL	12-2029			11,918,057	4,607,622	7,310,434	1,218,406	10.22	6.0	
TOTAL STEAM PRODUCTION PLANT				2,616,967,386	1,189,415,417	1,610,233,273	169,219,037	6.47		
330.99 HYDRAULIC PRODUCTION PLANT										
AVON	12-2066	100 - L0.5 a	(13)	19,190,750	7,374,478	14,311,070	418,280	2.18	34.2	
BEAR RIVER	12-2066	100 - L0.5 a	(15)	62,888,372	13,223,548	59,098,081	1,735,627	2.76	34.0	
BLACK RIVER	12-2066	100 - L0.5 a	(12)	56,119,196	12,773,630	50,079,869	1,465,503	2.61	34.2	
DICKIE BROOK	12-2066	100 - L0.5 a	(6)	16,019,562	1,175,021	15,805,714	460,490	2.87	34.3	
FALL RIVER	12-2066	100 - L0.5 a	(24)	2,433,707	440,846	2,576,950	75,314	3.09	34.2	
LEQUILLE	12-2066	100 - L0.5 a	(10)	42,258,224	5,550,380	40,933,667	1,198,840	2.84	34.1	
ST. MARGARETS	12-2066	100 - L0.5 a	(5)	52,563,783	13,049,922	42,142,051	1,218,918	2.32	34.6	
SHEET HARBOUR	12-2066	100 - L0.5 a	(8)	33,492,534	9,153,795	27,018,142	797,225	2.38	33.9	
TUSNET	100 - L0.5	(20)		23,001,082	5,585,327	22,015,983	400,170	1.74	55.0	
WRECK COVE	100 - L0.5	(20)		241,849,833	80,739,861	209,479,939	3,964,699	1.64	52.8	
MERSEY	100 - L0.5	(20)		40,259,998	20,874,637	27,437,361	567,195	1.41	48.4	
GENERAL				23,944,861	(2,085,374)	26,030,235	499,216	2.08		
TOTAL HYDRAULIC PRODUCTION PLANT				614,021,913	167,856,071	536,929,062	12,801,477	2.08		
340.96 SOLAR PRODUCTION PLANT										
SOLAR SMARTGRID	12-2051	45 - R2.5 a	0	1,582,854	98,009	1,484,845	61,606	3.89	24.1	
TOTAL SOLAR PRODUCTION PLANT				1,582,854	98,009	1,484,845	61,606	3.89		
340.99 OTHER PRODUCTION PLANT										
OTHER PRODUCTION - GAS TURBINES										
BURNSIDE	12-2049	75 - S0.5 a	(3)	43,645,266	14,071,208	30,883,416	1,309,193	3.00	23.6	
TUSNET	12-2049	75 - S0.5 a	(1)	17,461,600	6,878,555	10,757,681	448,016	2.57	24.0	
VICTORIA JUNCTION	12-2049	75 - S0.5 a	(6)	20,230,710	7,604,663	13,836,869	577,509	2.85	24.0	
TUFTS COVE										
TUFTS COVE CT UNIT 4	12-2049	30 - L0.5 a	(11)	57,829,237	11,119,148	53,071,305	3,829,244	6.62	13.9	
TUFTS COVE CT UNIT 5	12-2049	30 - L0.5 a	(11)	39,322,118	3,328,106	40,319,444	2,870,636	7.30	14.0	
TOTAL TUFTS COVE				97,151,355	14,447,255	93,390,749	6,699,880	6.63	13.9	
TOTAL OTHER PRODUCTION - GAS TURBINES				178,488,931	43,001,701	148,871,695	9,034,598	5.06		
OTHER PRODUCTION - WIND										
DIGBY	12-2036	90 - S0.5 a	(2)	67,721,102	30,355,934	38,719,590	3,047,396	4.50	12.7	
NUTTBY	12-2035	90 - S0.5 a	(2)	111,163,131	59,596,442	53,819,951	4,880,296	4.12	11.8	
CANSO/SABLE	12-2039	90 - S0.5 a	(2)	12,399,704	4,488,546	8,159,151	526,382	4.25	15.5	
SOUTH CANOE	12-2040	90 - S0.5 a	(1)	98,031,286	33,630,847	65,380,751	3,962,466	4.04	16.5	
TUPPER/BEARHEAD	12-2035	90 - S0.5 a	(2)	24,785,573	13,165,184	12,116,101	1,031,094	4.16	11.8	
TOTAL OTHER PRODUCTION - WIND				314,100,795	141,206,954	178,195,544	13,147,634	4.19		
TOTAL OTHER PRODUCTION PLANT				492,589,726	184,208,655	327,067,239	22,182,232	4.50		
TRANSMISSION PLANT										
350.10 LAND RIGHTS - EASEMENTS	80 - R5	0		100,622,597	26,905,421	73,717,175	1,330,578	1.32	55.4	
353.00 STATION EQUIPMENT	48 - R2.5	(20)		586,908,962	253,049,476	451,241,279	16,060,367	2.74	28.1	
354.00 TOWERS AND FIXTURES	60 - S2.5	(20)		111,028,870	73,423,125	59,811,519	1,449,984	1.31	41.2	
355.00 POLES AND FIXTURES	45 - R1.5	(20)		268,176,042	62,589,384	239,221,867	9,209,997	3.43	26.0	
356.00 OVERHEAD CONDUCTORS AND DEVICES	45 - R3	(20)		178,454,463	75,534,094	138,611,261	5,546,910	3.11	25.0	
357.00 UNDERGROUND CONDUIT	65 - S3	0		1,736,139	611,263	1,124,876	27,127	1.56	41.5	
358.00 UNDERGROUND CONDUCTORS AND DEVICES	45 - S3	(10)		7,345,546	853,459	7,226,642	194,359	2.65	37.2	
359.00 ROADS, TRAILS AND BRIDGES	60 - S3	0		344,183	110,123	234,060	6,260	1.82	37.4	
TOTAL TRANSMISSION PLANT				1,254,616,801	513,076,344	971,188,679	33,825,592	2.70		
DISTRIBUTION PLANT										
360.10 LAND RIGHTS - EASEMENTS, SURVEYS AND CLEARING	65 - R5	0		118,136,716	15,711,852	102,424,864	1,860,352	1.57	55.1	
361.00 STRUCTURES AND IMPROVEMENTS	55 - R3	(5)		2,418,694	750,104	1,789,525	40,916	1.69	43.7	
362.00 STATION EQUIPMENT	55 - R1.5	(5)		74,535,144	64,521,947	13,739,954	501,585	0.67	27.4	
362.10 SCADA EQUIPMENT	15 - S2.5	(5)		473,094	475,824	20,924	1,774	0.37	11.8	
362.20 REMOTE MONITORING EQUIPMENT	15 - S2.5	(5)		393,349	388,219	24,797	2,108	0.54	11.8	
362.30 STATION EQUIPMENT - MISCELLANEOUS	15 - S2.5	(5)		13,123,052	11,030,074	2,749,130	236,947	1.81	11.6	
363.10 ENERGY STORAGE EQUIPMENT - EV CHARGERS	15 - S3	0		987,094	158,436	828,658	71,330	7.23	11.6	
363.20 ENERGY STORAGE EQUIPMENT - DISTRIBUTED SOLAR	25 - S3	0		1,123,202	94,625	1,058,577	48,536	4.32	21.8	
363.30 ENERGY STORAGE EQUIPMENT - BATTERIES	10 - S3	0		1,261,438	201,460	1,059,978	141,434	11.21	7.5	
364.00 POLES, TOWERS AND FIXTURES	43 - R2	(35)		646,990,061	406,226,456	467,210,126	18,024,106	2.79	25.9	
365.00 OVERHEAD CONDUCTORS AND DEVICES	42 - R2	(26)		329,509,672	144,738,996	270,443,190	11,067,585	3.36	24.4	
366.00 UNDERGROUND CONDUIT	70 - S3	0		8,554,638	4,309,841	4,244,798	105,112	1.23	40.4	
367.00 UNDERGROUND CONDUCTORS AND DEVICES	42 - R3	(25)		75,012,364	33,657,017	60,108,439	2,407,126	3.21	25.0	
368.00 LINE TRANSFORMERS	35 - R1	(25)		555,455,934	237,671,905	456,648,012	23,885,113	4.30	19.1	
369.00 SERVICES	48 - S2.5	(65)		149,613,065	134,202,103	112,659,454	3,885,448	2.60	29.0	
370.00 METERS	20 - S2	(10)		6,155,844	6,077,871	693,557	40,535	0.66	17.1	
370.10 METERS - AMI	18 - S2	(10)		96,761,787	18,747,008	87,67				

Appendix “B”

Reduced OM&G	2026	2027
Energy Delivery	5,000,000	5,000,000
Customer Experience	2,000,000	2,000,000
Corporate	2,000,000	2,000,000
Total OM&G Reduction	9,000,000	9,000,000
Reduced Regulatory Amortization (GRA Deferral)	1,000,000	1,000,000
Total Reduced OM&G and Regulatory Amortization	10,000,000	10,000,000

Appendix “C”

Attached as a separate document starting on the next page.

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

Page 1 of 5

APPLICABILITY

This schedule applies to all electric rate classes with the exception of the Wholesale Market Non-Dispatchable Supplier Spill Tariff, the Load Retention Tariff, and the Extra Large Industrial Active Demand Control Tariff. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of the costs of electricity efficiency and conservation activities, as defined in Section 79A of the Public Utilities Act (Demand Side Management or DSM) approved by the Nova Scotia ~~Energy Utility and Review~~ Board (NS~~UAREB~~) will be direct billed in accordance with the customer's class energy bill as if served by Nova Scotia Power Incorporated (NS Power) under its bundled service offerings.

RESPONSIBILITIES OF FRANCHISE HOLDER

It is the responsibility of the holder of the electric efficiency and conservation franchise granted under Section 79C of the Public Utilities Act (Franchise Holder) to apply to the Nova Scotia ~~Utility and Review Board~~ (NS~~UAREB~~) to seek approval of all DSM activities, plans and programs, and to itemize and seek approval for all related costs.

On or before October 1 in the year preceding the implementation of the approved programs, NS Power shall apply to the NS~~UAREB~~ to seek approval of the DSM Cost Recovery Rider amounts to be inserted in Schedule A to this tariff for the succeeding rate year. NS Power shall pay to the Franchise Holder the amount approved by the NS~~UAREB~~ to fund the DSM costs, on a monthly basis.

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Rider is applicable shall be increased or decreased by the DCRR at a class-specific rate per kilowatt hour of consumption in accordance with the following formula:

$$\text{DCRR} = \text{PCR} + \text{BA}$$

Where:

PCR = Program Cost Recovery

The PCR includes all estimated costs for the upcoming calendar year for the DSM Plan that has been requested by the Franchise Holder and approved by the NS~~UAREB~~ (Approved DSM). It includes the cost of planning, developing, implementing, monitoring, evaluating, and verifying DSM programs, and includes but is not limited to costs for enabling strategies, consultants, employees, and administrative expenses. The PCR is computed for each rate schedule using the cost allocation methodology set out in Schedule B to this tariff.

Effective: January 1, 2026 ~~5~~ [January 1, 2026](#)

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

Page 2 of 5

BA = Balance Adjustment

The BA is comprised of two components:

(1) BA₁ = Annual Volume Variance Adjustment ~~– is~~ calculated for each rate class separately on a previously completed calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the PCR and the revenues which should have been billed based on actual class load in the previously completed calendar year, as follows: In order to enable incorporation of a full year's actual results, the BA₁ is applied on a two-year lag and will address differences in the year that occurred 2 years prior to the current PCR year¹.

~~(1)(2)~~ BA₂ = End of Approved DSM Term Adjustment – reconciles ~~The balance adjustment amount is~~ the difference between the Approved DSM amount billed in the previously completed ~~calendar year from the application of the PCR unit charges~~ Approved DSM Term² and the actual ~~cost of the~~ Approved DSM expenditures incurred by the Franchise Holder during the same previously completed ~~calendar year~~ Approved DSM Term. Following the conclusion of the Approved DSM Term, the BA₂ is calculated by customer class based on actual spending and is applied over the remainder of the succeeding Approved DSM Term³. This adjustment ensures that customers are charged or refunded based on actual DSM program expenditures in their respective class.

Total BA = BA₁ + BA₂

The BA shall be updated annually to reflect BA₁, and at the conclusion of each Approved DSM Term to reflect BA₂. The NSUAREB-approved DCRR shall be placed into effect with bills rendered on and after the effective date of such change.

SCHEDULE A**2025 DSM Cost Recovery Rider Charges**

The Demand Side Management Cost Recovery Rider (DCRR) charges, along with its components, (PCR) and (BA), for the period from the approved effective date of January 1, 2025 to December 31, 2025 are as follows:

¹ ~~Balance Adjustment for 2023 will come into effect on January 1, 2025 and will be based on the revenue collected between February 2, 2023, and December 31, 2023. The revenue will be compared to the DSM costs incurred in that same period.~~

² The Approved DSM Term refers to the full DSM Plan period in effect (e.g. 2023-2026, 2027-2031).

³ For example, following the conclusion of the 2023-2026 term, the BA₂ is calculated (in 2027) and is applied equally, on a per year basis, over the remainder of the 2027-2031 term (e.g. four years – 2028, 2029, 2030, and 2031).

Effective: January 1, 2026 ~~5~~ January 1, 2026

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

Page 3 of 5

Applicable Tariff	PCR (cents per kWh)	BA (cents per kWh)	DCRR (cents per kWh)
Domestic Service, Domestic Service Time-of-Day, Domestic Service Time-of-Use, Domestic Service Critical Peak Pricing	0.657	-0.024	0.633
Small General, Small General Time of Use, Small General Critical Peak Pricing	0.778	-0.025	0.753
General, General Time of Use, General Critical Peak Pricing	0.635	0.010	0.646
Large General	0.768	0.022	0.790
Small Industrial	0.720	0.033	0.753
Medium Industrial	0.306	0.008	0.314
Large Industrial including Interruptible Rider	0.404	0.027	0.430
Municipal	0.650	-0.023	0.628
Unmetered Services	0.353	0.004	0.357
Gen. Replacement & Load Following	0.110	-0.069	0.040
One Part Real Time Pricing	0.095	-0.004	0.091
Shore Power	0.095	0.059	0.153

SCHEDULE B**DSM Cost Allocation Method Approach**

~~There are 3 kinds of cost benefits resulting from DSM:~~

- ~~(1) *System*—avoided future infrastructure and related costs, reduced fuel costs, and contribution to achieving environmental and emissions restrictions. All customers receive these benefits.~~
- ~~(2) *Class*—when customers within a class participate, the whole class benefits by a reduction in their cost of service allocation, even those who do not actively participate.~~
- ~~(3) *Participation*—customers who are able to participate in DSM programs can lower their own electricity usage and therefore their costs.~~

~~The recovery of DSM costs from customers should reflect the level of benefit received by customer classes. Those customer classes who receive the most benefit (i.e. in all three categories) would bear the most responsibility to contribute to the costs. A customer class that receives only system benefits would contribute to the costs accordingly despite not directly participating in programs. Given the~~

Effective: January 1, 2026 ~~5~~ [January 1, 2026](#)

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

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~~nature of DSM programs and benefits it is not possible to precisely calculate and allocate costs based upon these various benefits.~~

Allocation of DSM Program Costs

~~System benefits are allocated to all applicable customer classes in accordance with the Cost of Service Study (COSS) methodology reflecting allocation of generation rate base as per the most recent rate case decision.~~

~~Once system benefits have been allocated, the remaining costs relate to the class and participation benefits. These costs are assigned to the class(es) participating in the DSM programs in proportion to amounts invested in each class.~~

Method

- ~~• Step 1 – Allocate the system benefits to all applicable customer classes, as 25% of the total Approved DSM program costs, in accordance with the COSS methodology per the most recent rate case decision.~~
- Step 21 – Allocate the class and participation benefits by directly assigning 75100% of the DSM investment identified for each participating customer class.
- ~~• Step 3 – Add the amounts from Step 1 and Step 2 to obtain the total amount to be recovered from each class.~~
- Step 42 – For NS Power bundled service customers, divide the total amount to be recovered from each class by the anticipated electricity sales for the class to derive the required program cost recovery for each class for the upcoming year.
- Step 53 – For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be direct billed in accordance with the customer's class energy bill if served by NS Power under its bundled service offerings.
- Step 64 – Annually, true up the class and participation benefits by customer class, as described in BA₁~~based upon actual experience in the 2 years prior to the current PCR year.~~
- Step 5 – At the end of each Approved DSM Term, true up the class and participation benefits by customer class, as described in BA₂.

Conditions

Effective: January 1, 20265January 1, 2026

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)**Page 5 of 5**

-
- For bundled service customers other than those who take service in the Wholesale Market (whether in whole or in part), this approach applies to classes as a whole (not to individual customers).
 - For customers who take service in the Wholesale Market (whether in whole or in part), this approach applies to individual customers.
 - This approach applies to total Approved DSM costs.

CONFIDENTIAL (Attachment Only)

1 **Request IR-2:**

2
3 **Please file the regulated and unregulated financial statements of NS Power for the year ended**
4 **December 31, 2024.**

5
6 Response IR-2:

7
8 Please refer to Partially Confidential Attachment 1 for NS Power's Regulated Financial Statement.

9
10 Please refer to Attachment 2 for NS Power's Consolidated Financial Statement.

11
12 Please refer to Attachment 3 for NS Power's Management Discussion and Analysis.

Financial Statements
Nova Scotia Power Inc.

Regulated Statements of Income

For the millions of Canadian dollars	Three months ended December 31						Year ended December 31	
	<i>Actual</i>	<i>Test Year</i>		<i>Prior Year</i>	<i>Actual</i>	<i>Test Year</i>		<i>Prior Year</i>
	2024	2024		2023	2024	2024		2023
Operating revenues	\$ 478	\$ 468	\$	439	\$ 1,854	\$ 1,795	\$	1,670
Operating expenses								
Fuel for generation and purchased power	(216)	242		234	509	941		777
Fuel adjustment mechanism	436	(21)		(47)	350	(88)		(78)
Demand side management cost recovery rider	-	-		1	(1)	-		1
Storm cost recovery rider	-	-		(17)	(1)	-		(21)
Settlement agreement adjustment	-	(9)		-	-	(36)		-
Operating, maintenance and general	85	75		100	328	298		326
Demand side management	15	15		13	58	58		50
Provincial grants and taxes	12	11		11	48	44		45
Depreciation and amortization	72	74		69	280	287		274
Total operating expenses	404	387		364	1,571	1,504		1,374
Income from operations	74	81		75	283	291		296
Other income, net	(7)	(9)		(7)	(28)	(41)		(29)
Interest expense, net	41	33		40	164	130		175
Income before provision for income taxes	40	57		42	147	202		150
Income tax (recovery) expense	(39)	-		-	(33)	-		(5)
Net income	\$ 79	\$ 57	\$	42	\$ 180	\$ 202	\$	155

Regulated Balance Sheets

As at millions of Canadian dollars	December 31 2024	December 31 2023
Assets		
Current assets		
Cash and cash equivalents	\$ -	\$ 78
Receivables, net	417	430
Due from related parties	95	85
Inventory	295	345
Derivative instruments	28	9
Regulatory assets	67	61
Prepaid expenses	24	25
Total current assets	926	1,033
Property, plant and equipment, net of accumulated depreciation	4,908	4,720
Other assets		
Income taxes receivable	87	82
Derivative instruments	16	2
Pension and post-retirement assets	185	90
Regulatory assets	974	1,238
Other long-term assets	49	56
Total other assets	1,311	1,468
Total assets	\$ 7,145	\$ 7,221

	December 31 2024	December 31 2023
Liabilities and Equity		
Current liabilities		
Short-term debt	2	-
Current portion of long-term debt	125	-
Accounts payable	197	183
Income taxes payable	3	1
Derivative instruments	25	56
Regulatory liabilities	29	12
Pension and post-retirement liabilities	8	8
Other current liabilities	142	132
Total current liabilities	531	392
Long-term liabilities		
Long-term debt	3,217	3,868
Due to related parties	-	2
Deferred income taxes	899	797
Derivative instruments	13	21
Regulatory liabilities	71	3
Asset retirement obligations	137	132
Pension and post-retirement liabilities	67	68
Redeemable preferred shares	10	-
Other long-term liabilities	51	40
Total long-term liabilities	4,465	4,931
Equity		
Common stock	1,415	1,414
Accumulated other comprehensive loss	(8)	(78)
Retained earnings	742	562
Total equity	2,149	1,898
Total liabilities and equity	\$ 7,145	\$ 7,221

Regulated Operating Revenues

For the millions of Canadian dollars		Three months ended December 31				Year ended December 31	
	<i>Actual</i> 2024		<i>Test Year</i> 2024	<i>Prior Year</i> 2023	<i>Actual</i> 2024	<i>Test Year</i> 2024	<i>Prior Year</i> 2023
Electric Revenues							
Residential	260		\$ 246	\$ 239	997	\$ 928	\$ 910
Commercial							
Small General	17		15	15	68	61	59
General	98		98	92	379	381	355
Large General	13		14	12	52	58	49
Total Commercial	128		127	119	499	500	463
Industrial							
Small Industrial	10		11	10	41	43	39
Medium Industrial	19		18	16	72	69	64
Large Industrial	21		24	20	83	94	85
ELIADC/Load Retention and Other Industrial	19		25	16	80	97	31
Total Industrial	69		78	62	276	303	219
Other							
Municipal	4		1	5	18	6	18
Unmetered	5		5	4	20	20	19
Wholesale Market	1		2	1	3	5	3
Total Other	10		8	10	41	31	40
Total In-Province Electric Revenues	467		459	430	1,813	1,762	1,632
Export Revenues	-		-	-	-	-	1
Total Electric Revenues	467		459	430	1,813	1,762	1,633
Other Operating Revenues	11		9	9	41	33	37
Total Operating Revenues	\$ 478		\$ 468	\$ 439	\$ 1,854	\$ 1,795	\$ 1,670

Regulated Operating, Maintenance and General

For the millions of Canadian dollars		Three months ended December 31				Year ended December 31	
		<i>Actual</i> 2024	<i>Test Year</i> 2024 ⁽¹⁾	<i>Prior Year</i> 2023	<i>Actual</i> 2024	<i>Test Year</i> 2024 ⁽¹⁾	<i>Prior Year</i> 2023
Power Production	\$ 25		\$ 25	\$ 25	\$ 102 ²	\$ 99	\$ 98
Enterprise Asset Management and Project Implementation	1		3	2	8 ³	10	9
Environment	1		1	1	3	3	3
Customer Operations	30		24	48	129 ⁴	99	146
Customer Service	9		7	7	29 ⁵	26	26
Corporate Groups	25		23	25	108 ⁶	95	93
Corporate Adjustments	(7)		(11)	(8)	(56) ⁷	(46)	(52)
Pension	1		3	-	5 ⁸	12	3
Total Operating Maintenance and General	\$ 85		\$ 75	\$ 100	\$ 328	\$ 298	\$ 326

Notes:

1. Quarterly test year figures are based on an allocation of the annual test year amounts as these amounts are not profiled quarterly.
2. Increased compared to test year primarily due to increased thermal plant costs, partially offset by decreased costs in renewables.
3. Decrease compared to test year primarily due to decreased operational costs for generation asset management and project costs.
4. Increased compared to test year due to increased operational costs for fleet, line services, utility services, and meter and inspection services.
5. Increased compared to test year primarily due to increased operating costs in the Customer Care group.
6. Increased compared to test year primarily due to increased operating costs for information technology and facilities and procurement.
7. Decreased compared to test year primarily due to increased administrative overhead credits as a result of the capital program.
8. Decreased compared to test year due to changes in actuarial assumptions.

Summary of Unregulated Adjustments

As at	December 31
millions of Canadian dollars	2024

Unregulated Retained Earnings

Unregulated retained earnings - December 31, 2023	\$181.8
Unregulated compensation (including director share units/performance share units and management incentive)	18.5
Interest expense, unregulated assets	2.3
Depreciation expense, unregulated assets	1.8
Donations and sponsorships	1.8
Fuel adjustment mechanism disallowance	2.8
Performance standards penalty	1.2
Other	(1.3)
Unregulated rental income from Lower Water Street	(0.7)
Income taxes, unregulated adjustments	(8.5)
Interest income, fuel adjustment mechanism provision reversal	1.1
Subtotal	19.0
Unregulated retained earnings - December 31, 2024	\$200.8

Unregulated Property, Plant and Equipment

Unregulated Portion of Maritime Link Project	\$36.1
Unapproved Authorization to Overspend	13.5
Unregulated Portion of Lower Water Street	8.6
Burnside Natural Gas Conversion Project	2.8
Kentville Electric Purchase Price Discrepancy Goodwill	2.3
Unregulated Portion of Tufts Cove 6 Project	1.5
Other unapproved capital projects	-
Unregulated Land	1.0
Electric Vehicle Charging Station Project, net of government contributions	0.2
Total unregulated property, plant and equipment	\$66.0

Unregulated Other Assets

Deferred General Rate Application costs	\$0.3
Deferred Nova Scotia Independent Energy System Operator costs	0.1
Sponsorship	0.7
Total unregulated other assets	\$1.1

Unregulated Deferred Income Taxes

Increase to long-term deferred income taxes liability related to unregulated expenditures	\$160.1
Total unregulated deferred income taxes	\$160.1

Unregulated Due to Related Parties

Due to Emera related to Part VI.1 Tax	(\$137.5)
Total unregulated due to related parties	(\$137.5)

Common Stock

Equity issuance classified as regulated repayment of Due From Related Parties	(\$183.0)
Total Common Stock	(\$183.0)

Unregulated Due from Related Parties

Effect of unregulated adjustments	\$107.5
Effect of unregulated adjustments	\$107.5

Nova Scotia Power Inc.

Regulated Return on Equity

As at	December 31	
millions of Canadian dollars	2024	
	Regulated Equity	Regulated Capitalization
December 31, 2023	\$1,977.1	\$5,676.0
March 31, 2024	2,039.6	5,785.2
June 30, 2024	2,060.8	5,664.4
September 30, 2024	2,078.2	5,714.1
December 31, 2024	2,156.1	5,391.0
Total	\$10,311.8	\$28,230.6
Five Quarter Average	\$2,062.4	\$5,646.1
Five Quarter Average Regulated Common Equity		36.5%
Regulated Net Earnings - December 31, 2024	\$179.5	
Regulated Return on Equity (Regulated Net Earnings / Average Regulated Common Equity)	8.70%	

NOVA SCOTIA POWER INC.
Consolidated Financial Statements
December 31, 2024 and 2023

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Nova Scotia Power Inc. ("NSPI" or "the Company") and the information in the Management's Discussion & Analysis ("MD&A") are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented in the MD&A and has ensured that it is consistent with that in the consolidated financial statements.

NSPI maintains effective systems of internal accounting and controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that NSPI's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements.

The Board meets periodically with management, internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the MD&A, the consolidated financial statements and the external auditors' report. The Board also considers, for review and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Board.

February 21, 2025

"Peter Gregg"
President and Chief Executive Officer

"Greg Blunden"
Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Nova Scotia Power Inc.

Opinion

We have audited the consolidated financial statements of Nova Scotia Power Inc. and its subsidiary (the "Company"), which comprise the consolidated balance sheets as at December 31, 2024 and 2023, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2024 and 2023, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other information

Management is responsible for the other information. The other information comprises Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 21, 2025

Nova Scotia Power Inc. Consolidated Statements of Income

For the millions of dollars	Year ended December 31	
	2024	2023
Operating revenues (note 4)	\$ 1,855	\$ 1,671
Operating expenses		
Fuel for generation and purchased power (notes 15 and 16)	509	777
Fuel adjustment mechanism ("FAM") and other deferrals (note 5)	350	(98)
Operating, maintenance and general ("OM&G")	350	350
Demand side management ("DSM")	58	50
Provincial grants and taxes	48	45
Depreciation and amortization	282	276
Total operating expenses	1,597	1,400
Income from operations	258	271
Other income, net	(28)	(32)
Interest expense, net (note 6)	168	170
Income before provision for income taxes	118	133
Income tax recovery (note 7)	(42)	(8)
Net income	\$ 160	\$ 141

The accompanying notes are an integral part of these consolidated financial statements.

Nova Scotia Power Inc. Consolidated Statements of Comprehensive Income

For the millions of dollars	Year ended December 31	
	2024	2023
Net income	\$ 160	\$ 141
Other comprehensive income (loss)		
Net change in unrecognized pension and post-retirement costs (note 8)	70	(41)
Comprehensive income	\$ 230	\$ 100

The accompanying notes are an integral part of these consolidated financial statements.

Nova Scotia Power Inc. Consolidated Balance Sheets

As at millions of dollars	December 31 2024	December 31 2023
Assets		
Current assets		
Cash	\$ -	\$ 78
Receivables, net (note 9)	417	430
Inventory (note 10)	295	345
Derivative instruments (notes 11 and 12)	28	9
Regulatory assets (note 5)	67	61
Prepaid expenses	24	25
Total current assets	831	948
Property, plant and equipment , net of accumulated depreciation of \$3,499 and \$3,350 respectively (note 13)	4,974	4,779
Other assets		
Income taxes receivable	87	82
Derivative instruments (notes 11 and 12)	16	2
Pension and post-retirement asset (note 14)	185	90
Regulatory assets (note 5)	974	1,238
Other long-term assets (note 15)	50	82
Total other assets	1,312	1,494
Total assets	\$ 7,117	\$ 7,221
Liabilities and Equity		
Current liabilities		
Bank indebtedness	\$ 2	\$ -
Current portion of long-term debt (note 18)	125	-
Accounts payable	197	183
Due to related parties (note 16)	13	13
Income taxes payable	3	1
Derivative instruments (notes 11 and 12)	25	56
Regulatory liabilities (note 5)	29	12
Pension and post-retirement liabilities (note 14)	8	8
Other current liabilities (note 17)	142	132
Total current liabilities	544	405
Long-term liabilities		
Long-term debt (note 18)	3,217	3,868
Due to related parties (note 16)	137	110
Deferred income taxes (note 7)	739	674
Derivative instruments (notes 11 and 12)	13	21
Regulatory liabilities (note 5)	71	3
Asset retirement obligations (note 19)	137	132
Pension and post-retirement liabilities (note 14)	67	68
Redeemable preferred stock (note 21)	10	-
Other long-term liabilities (note 15)	51	40
Total long-term liabilities	4,442	4,916
Equity		
Common stock, no par value, unlimited shares authorized, 173.5 million and 173.4 million shares issued and outstanding, respectively	1,598	1,597
Accumulated other comprehensive loss ("AOCL") (note 8)	(8)	(78)
Retained earnings	541	381
Total equity	2,131	1,900
Total liabilities and equity	\$ 7,117	\$ 7,221

Commitments and contingencies (note 20)

Approved on behalf of the Board of Directors

The accompanying notes are an integral part of these consolidated financial statements.

"Scott Balfour"
Chair of the Board"Peter Gregg"
President and Chief Executive Officer

Nova Scotia Power Inc.

Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31	
	2024	2023
Operating activities		
Net income	\$ 160	\$ 141
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	283	277
Allowance for equity funds used during construction	(7)	(6)
Deferred income taxes, net	(41)	(8)
Net change in pension and post-retirement obligations	(26)	(28)
FAM	451	(88)
Other operating activities, net	11	(10)
Changes in non-cash working capital:		
Receivables, net	13	(55)
Income taxes receivable	(5)	(4)
Inventory	50	(58)
Prepaid expenses	1	(6)
Due from/to related parties	-	10
Accounts payable	17	(150)
Income taxes payable	2	(4)
Other current liabilities	10	(127)
Net cash provided by (used in) operating activities	919	(116)
Investing activities		
Additions to property, plant and equipment	(447)	(426)
Allowance for borrowed funds used during construction	(6)	(5)
Removal of assets from service, net of salvage	(34)	(24)
Proceeds from sale of assets	2	6
Other investing activities	2	-
Net cash used in investing activities	(483)	(449)
Financing activities		
Change in bank indebtedness	2	-
Proceeds from long-term debt	19	500
Net repayments under committed credit facility	(544)	(160)
Issuance of common stock	1	308
Payments on long-term payable	-	(5)
Other financing activities	8	(2)
Net cash (used in) provided by financing activities	(514)	641
Net change in cash	(78)	76
Cash, beginning of year	78	2
Cash, end of year	\$ -	\$ 78

Supplemental disclosure of cash paid:

Interest	\$ 196	\$ 193
Income taxes, net of refunds (1)	\$ 27	\$ 30

Supplemental disclosure of non-cash activity:

Decrease in accrued capital expenditures	\$ (3)	\$ (8)

(1) Income taxes paid includes \$28 million (2023 – \$30 million) of Part VI.1 tax that is transferred from, and fully funded by, Emera Incorporated ("Emera").

The accompanying notes are an integral part of these consolidated financial statements.

Nova Scotia Power Inc.
Consolidated Statements of Changes in Equity

millions of dollars		Common Stock		AOCL		Retained Earnings		Total Equity
Balance, December 31, 2023	\$	1,597	\$	(78)	\$	381	\$	1,900
Net income		-		-		160		160
Other comprehensive income		-		70		-		70
Issuance of common stock		1		-		-		1
Balance, December 31, 2024	\$	1,598	\$	(8)	\$	541	\$	2,131

millions of dollars		Common Stock		AOCL		Retained Earnings		Total Equity
Balance, December 31, 2022	\$	1,289	\$	(37)	\$	240	\$	1,492
Net income		-		-		141		141
Other comprehensive loss		-		(41)		-		(41)
Issuance of common stock		308		-		-		308
Balance, December 31, 2023	\$	1,597	\$	(78)	\$	381	\$	1,900

The accompanying notes are an integral part of these consolidated financial statements.

Nova Scotia Power Inc.

Notes to the Consolidated Financial Statements

As at December 31, 2024 and 2023

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Nova Scotia Power Inc. ("NSPI" or the "Company") is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada, providing electricity generation, transmission and distribution services to approximately 557,000 customers. NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia ("the Act") and is subject to regulation by the Nova Scotia Utility and Review Board ("UARB"). The Company's accounting policies are subject to examination and approval by the UARB.

NSPI is a wholly owned subsidiary of Emera Incorporated ("Emera"). NSPI holds a 100 per cent investment in NS Power Energy Marketing Incorporated ("NSPEMI"), an energy business that purchases and sells electricity and natural gas in the United States ("US") energy commodity market. Intercompany balances and intercompany transactions have been eliminated on consolidation.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP") and in the opinion of management, include all adjustments that are of a recurring nature and necessary to fairly state the financial position of NSPI.

All dollar amounts are presented in Canadian dollars ("CAD"), unless otherwise indicated.

Principles of Consolidation

These consolidated financial statements include the accounts of NSPI and its wholly-owned subsidiary, NSPEMI.

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIE"). To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity.

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. The rates are designed to recover prudently incurred costs of providing the regulated products or services and provide an opportunity for a reasonable rate of return on invested capital, as applicable (refer to note 5 for additional details).

Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to CAD at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Revenue Recognition

Regulated electric revenue:

Electric revenues, including energy charges, demand charges, basic facilities charges and clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the electricity. Electric revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the UARB and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of megawatt hours ("MWh") delivered to customers at the established rates expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

Other:

Other revenues are recorded when obligations under the terms of the contract are satisfied.

Property, Plant and Equipment

Property, plant, and equipment ("PP&E") is recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E are replaced, renewed, or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO and overhead attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance.

Normal maintenance projects and major maintenance projects that do not increase the overall life of the related assets are expensed as incurred. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB. The last depreciation study was completed in 2010.

Intangible assets, which are included in “PP&E” on the Consolidated Balance Sheets, consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the assets in each category. The estimated service lives of intangible assets requires regulatory approval.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of PP&E until the asset is operational. The Company includes an equity cost component in AFUDC, in addition to a charge for borrowed funds. AFUDC is a non-cash item and cash is realized under the rate-making process over the service life of the related PP&E through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to “Interest expense, net”, while the equity component is included as a reduction to “Other income, net”. AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the UARB and is compounded semi-annually.

Income Taxes and Investment Tax Credits

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the consolidated financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in the period when the change is enacted. NSPI recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred income tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred income tax assets and liabilities are made. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to reflect the amount of the deferred income tax asset expected to be realized.

Investment tax credits arise as a result of incurring qualifying scientific research and development expenditures and are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not.

NSPI collects income taxes from customers based on income tax that is currently payable except for the deferred income taxes on certain regulatory balances specifically prescribed by the UARB. For the balance of regulated deferred income taxes, NSPI recognizes regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

NSPI classifies interest and penalties associated with unrecognized tax benefits in the Consolidated Statements of Income as “Interest expense, net” and “OM&G”, respectively. Refer to note 7 for further details.

Derivatives and Hedging Activities

NSPI’s risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established several processes and practices to identify, monitor, report on

and mitigate material risks to the Company. A corporate team independent from operations is responsible for tracking to report on market and credit risks.

The Company manages its exposure to normal operating and market risks relating to commodity prices, and foreign exchange through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil, natural gas and purchased power, options, forwards, and swaps. Collectively, these contracts are considered derivatives.

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales (“NPNS”) exception. Physical contracts that meet the NPNS exception are not recognized on the balance sheet; these contracts are recognized in income when they settle. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company’s business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. NSPI continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Derivatives entered into by NSPI, that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment, as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. The UARB has approved that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Derivatives that do not meet any of the above criteria are designated as held-for-trading (“HFT”), with changes in fair value normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

NSPI classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory, OM&G and PP&E, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables, net” and obligations to return cash collateral are recognized in “Accounts payable”.

Leases

NSPI determines whether a contract contains a lease at inception by evaluating if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

NSPI has leases with independent power producers (“IPP”) and other utilities with annual requirements to purchase wind and hydro energy over varying contract lengths that are classified as finance leases. These finance leases are not recorded on NSPI’s Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as “Fuel for Generation and Purchased Power” on the Consolidated Statements of Income.

Operating lease liabilities and right-of-use assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at the

commencement date. As most of NSPI's leases do not provide an implicit rate, the incremental borrowing rate at the commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as "OM&G" on the Consolidated Statements of Income.

Where NSPI is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that consists of the sum of the minimum lease payments and residual value, net of estimated executory costs and unearned income. The difference between the gross investment and the cost of the leased item is recorded as unearned income at the inception of the lease. Unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

For sales-type leases, the accounting is similar to the accounting for direct finance leases, however the difference between the fair value and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

NSPI has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component for all leases.

Receivables and Allowance for Credit Losses

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales are 30 days for bi-monthly customers and 20 days for monthly customers. A late payment fee may be assessed on account balances after the due date.

The Company recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Credit risk assessments are conducted on all new customers and deposits are requested on any high-risk accounts in accordance with the Company's policy. The Company also maintains provisions for expected credit losses, which are assessed on a regular basis.

Management estimates credit losses related to accounts receivable by considering historical loss experience, current events, characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

Inventory

Fuel and materials inventories are valued at the lower of cost or net realizable value, unless evidence indicates that the weighted-average cost will be recovered in future customer rates.

Asset Impairment

Long-lived assets and intangibles are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. NSPI bases its evaluation of long-lived assets and intangibles on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors. If the sum of the undiscounted cash flows expected from an asset is less than the carrying value of the asset, the asset is written down to fair value.

The review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived

asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value. The Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment, or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Differences between accretion expense recognized for rate regulatory purposes and USGAAP, and accretion expense not yet approved by the UARB, are deferred to "PP&E" and included in the next depreciation study.

As at December 31, 2024 and 2023, some of the Company's transmission and distribution assets may have conditional AROs which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations, and a liability is recognized at fair value in the period in which an amount can be determined.

Cost of Removal

The Company recognizes non-ARO costs of removal ("COR") as regulatory liabilities or regulatory assets. The non-ARO COR represents funds received from customers through depreciation rates to cover estimated future non-legally required cost of removal and decommissioning of PP&E upon retirement, net of the costs incurred by the Company for non-legally required cost of removal and decommissioning activities. The Company accrues removal costs over the life of the related assets based on the depreciation studies approved by the UARB. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Stock-Based Compensation

The Company participates in several Emera stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; a performance share unit ("PSU") plan; and a restricted share unit ("RSU") plan. The Company accounts for its plans in accordance with the fair value-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as

liabilities are initially measured at fair value and re-measured at fair value at each reporting date with the change in liability recognized in income.

Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL. The components of net periodic benefit cost other than the service cost component are included in "Other income, net" on the Consolidated Statements of Income. Refer to note 14 for further details.

Government Grants

The Company accounts for government grants by applying a grant accounting model by analogy to International Accounting Standards ("IAS") 20, *Accounting for Government Grants and Disclosure of Government Assistance*. A grant relating to an asset is reflected in the determination of the carrying amount of the asset. A grant relating to income is presented as a deduction from the related expense it is intended to compensate.

In 2024, the Company received an aggregate of \$39 million (2023 – \$7 million) of government grants from various Canadian government agencies towards capital projects included in PP&E. The capital projects receiving grants primarily relate to the Company's decarbonization and environmental compliance initiatives. Further details on significant grant programs utilized in 2024 and 2023 are noted below.

Natural Resources Canada ("NRCan") Smart Renewables & Electrification Pathways ("SREP"):
On March 27, 2024 NSPI was approved for a grant under the NRCan SREP program to fund the construction of three 50 MW battery storage systems in Nova Scotia. NSPI can make claims under the grant until March 31, 2027, for 33 per cent of total eligible project costs to a maximum \$109 million. For the year-end December 31, 2024, NSPI received \$26 million (2023 – nil) in funding under the grant, which has been recorded as a reduction to the carrying amount of the project in PP&E.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policy that is applicable to, and adopted by the Company in 2024, is described as follows:

Improvements to Reportable Segment Disclosures

The Company adopted Accounting Standard Update ("ASU") 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance was effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Adoption of the standard resulted in additional qualitative disclosures provided in note 23.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB but as allowed, have

not yet been adopted by NSPI. Any ASUs not included below were assessed and determined to be either not applicable to the Company or have an insignificant impact on the consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, Income Statement Reporting—Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard update improves the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation and amortization) included within income statement expense captions. The guidance will be effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The standard updates are to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements disclosures.

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements disclosures.

4. REVENUE

The following disaggregates the Company's revenue by major source:

For the millions of dollars	Year ended December 31	
	2024	2023
Residential	\$ 997	\$ 910
Commercial	499	463
Industrial	276	219
Other	41	41
Electric revenue	1,813	1,633
Other revenue (1)	42	38
Operating revenues	\$ 1,855	\$ 1,671

(1) Includes revenue which does not represent revenues from contracts with customers.

Remaining Performance Obligations

The remaining performance obligations primarily represent the transaction prices of a long-term steam supply agreement. As of December 31, 2024, the aggregate amount of the transaction price allocated to remaining performance obligations was \$12 million. The Company expects to recognize revenue for the remaining performance obligations through Q3 2027.

5. REGULATORY MATTERS

The Company is a public utility as defined in the Act and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. The Company is not subject to a general annual rate review process, but rather participates in hearings held from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide an appropriate return to investors. NSPI's approved regulated return on equity ("ROE") range is 8.75 per cent to 9.25 per cent based on an actual five-quarter average regulated common equity component of up to 40 per cent of approved rate base.

Regulatory Environment and Updates

Federal Loan Guarantee:

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSP Maritime Link Inc. ("NSPML") and the Province of Nova Scotia on terms and conditions for a federal loan guarantee of \$500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On September 25, 2024, NSPI and NSPML filed applications with the UARB related to the federal loan guarantee. On November 29, 2024, the UARB approved NSPML's application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance. On February 18, 2025, the UARB approved NSPI's application to increase 2025 fuel rates to service the incremental NSPML debt.

Maritime Link:

The Maritime Link is a \$1.8 billion (including AFUDC) transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018, and NSPI started interim assessment payments to NSPML at that time.

On November 29, 2024, NSPML received UARB approval to collect up to \$197 million from NSPI for the recovery of costs associated with the Maritime Link in 2025, subject to a monthly holdback of up to \$4 million. The approved costs include \$158 million related to the 2025 annual cost assessment and a supplemental assessment of \$39 million as part of the repayment of the federal loan guarantee.

Battery Energy Storage System Project ("BESS Project"):

On June 13, 2024, the UARB approved \$238 million of capital investment, including AFUDC, for the BESS Project. The project is comprised of three 50 MW, four-hour battery facilities. Two facilities are anticipated to be in-service in late 2025 and the third facility in 2026.

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent prudently incurred costs that have been deferred because it is probable that they will be recovered through future rates collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the UARB, or due to regulatory precedent set for similar circumstances. If Management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If Management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

Regulatory assets and liabilities as at December 31, excluding certain regulatory assets related to PP&E and AROs as discussed in notes 13 and 19, consisted of the following:

As at millions of dollars	December 31 2024	December 31 2023
Regulatory assets		
Deferred income tax regulatory asset	\$ 922	\$ 787
Deferrals related to derivative instruments	40	78
Hurricane Fiona	32	-
Storm rider	23	21
Cost of removal	8	-
FAM (refer to table below)	-	395
Other	16	18
	\$ 1,041	\$ 1,299
Current	\$ 67	\$ 61
Long-term	974	1,238
Total regulatory assets	\$ 1,041	\$ 1,299
Regulatory liabilities		
FAM (refer to table below)	\$ 56	\$ -
Deferrals related to derivative instruments	44	12
Other	-	3
	\$ 100	\$ 15
Current	\$ 29	\$ 12
Long-term	71	3
Total regulatory liabilities	\$ 100	\$ 15

Deferred Income Tax Regulatory Asset:

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the consolidated financial statements or income tax returns, in accordance with NSPI's rate-regulated accounting policy as approved by the UARB. To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, NSPI recognizes a net deferred income tax regulatory asset or liability as appropriate.

Deferrals Related to Derivative Instruments:

NSPI defers changes in fair value of derivatives that are documented as economic hedges or that do not qualify for NPNS exception, as a regulatory asset or liability as approved by the UARB. The realized gain or loss is recognized when the hedged item settles in "Fuel for generation and purchased power", "Other income, net", "Inventory", "OM&G" or "PP&E", depending on the nature of the item being economically hedged.

Storm Rider:

NSPI has a UARB approved a storm rider for each of 2023, 2024 and 2025, which gives NSPI the ability to apply to the UARB for recovery of costs if major storm restoration expense exceeds approximately \$10 million in a given year. The storm rider was effective as of the February 2, 2023 GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application.

On December 2, 2024, the UARB approved the recovery of \$24 million of major storm restoration and incremental financing costs deferred to NSPI's storm rider in 2023 to be recovered over a 12-month period beginning on January 1, 2025.

Hurricane Fiona:

On June 27, 2024, the UARB approved the deferred recognition of \$25 million in incremental operating costs incurred during the Hurricane Fiona storm restoration efforts in September 2022. Following the UARB approval, the \$25 million was reclassified to "Regulatory assets" from "Other long-term assets".

The UARB also directed NSPI to reclassify \$10 million of undepreciated costs related to assets retired because of Hurricane Fiona to "Regulatory assets" from "Property, plant and equipment" on the Consolidated Balance Sheets. NSPI began amortizing both of these regulatory assets over a 10-year period beginning on July 1, 2024.

FAM:

On April 17, 2024, the UARB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the \$117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to an independent audit. On February 21, 2024, the UARB's decision on the FAM audit findings and recommendations relating to fiscal 2020 and 2021 were publicly released and included one disallowance. The disallowance of \$3 million was recorded in Q1 2024 in "FAM and other deferrals" with the associated interest expense of \$1 million recorded in "Interest expense, net". The total \$4 million was returned to customers through the FAM.

On July 5, 2024, the FAM audit results for fiscal 2022 and 2023 were publicly released and filed with the UARB. A UARB regulatory process is in progress and a hearing will be held in March 2025. The change in the FAM regulatory asset balances consisted of the following:

millions of dollars	2024	2023
FAM regulatory asset – Balance as at January 1	\$ 395	\$ 307
Interest on FAM balance (1)	21	11
2020 – 2021 FAM disallowance, including interest	(4)	-
FAM sale to Invest Nova Scotia	(117)	-
Total under (over) recovery fuel costs	(350)	78
Other	(1)	(1)
FAM regulatory asset (liability) – Balance as at December 31	\$ (56)	\$ 395

(1) 2023 includes the Q1 2023 reversal of interest previously recognized on the Nova Scotia Cap-and-Trade provision.

FAM and Other Deferrals

"FAM and other deferrals" recognized in the Consolidated Statements of Income consisted of the following:

For the millions of dollars	Year ended December 31 2024	2023
FAM:		
Over (under)-recovery of fuel costs (1) (2)	\$ 350	\$ (78)
2020 – 2021 FAM disallowance, excluding interest	3	-
DSM Rider: (Under) over recovery of DSM program costs	(1)	1
Storm Rider: Deferred major storm restoration expense	(1)	(21)
Other	(1)	-
Total FAM and other deferrals	\$ 350	\$ (98)

(1) In Q4 2024, NSPI received refund of previous NSPML assessment payments, resulting in \$486 million over-recovery of fuel costs. For further details refer to the "Regulatory Environment and Updates" section above.

(2) In Q1 2023, NSPI recorded a reversal of Nova Scotia Cap-and-Trade Program compliance costs, resulting in a \$166 million under-recovery of fuel costs. For further details refer to the "Other Regulatory Matters" section below.

The regulatory asset or liability balance associated with these deferrals as at December 31, 2024 (refer to the "Regulatory Assets and Regulatory Liabilities" section) includes associated interest which is recorded as "Interest expense, net" on the Consolidated Statements of Income.

Other Regulatory Matters

Nova Scotia Renewable Electricity Regulations (“RER”):

On May 26, 2023, NSPI initiated an appeal, through a proceeding with the UARB, of the \$10 million penalty levied on NSPI by the Province for non-compliance with the RER compliance period ending in 2022. The hearing for the matter is currently scheduled for June 2025.

Nova Scotia Cap-and-Trade (“Cap-and-Trade”) Program:

On January 1, 2023, the FAM included a cumulative \$166 million in fuel costs related to the accrued purchase of emissions credits and \$6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province of Nova Scotia provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. As such, compliance costs accrued of \$166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of \$6 million were not refunded and no further costs were incurred to achieve compliance with the Cap-and-Trade Program.

Extra Large Industrial Active Demand Tariff:

On July 5, 2023, NSPI received UARB approval to change the methodology by which fuel recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the cost of fuel to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a \$51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled customer accounts receivable within Receivables, net. This adjustment had minimal impact on earnings.

6. INTEREST EXPENSE, NET

For the millions of dollars	Year ended December 31	
	2024	2023
Interest on debt	\$ 197	\$ 202
Interest on FAM balance	(19)	(11)
Interest revenue, net	(9)	(10)
Reserve on interest on FAM balance (1)	-	(8)
Allowance for borrowed funds used during construction	(6)	(5)
Other	5	2
	\$ 168	\$ 170

(1) In 2022, a reserve was recorded against the portion of the interest on the FAM balance related to the non-cash Cap-and-Trade accrual. The reserve was reversed in Q1 2023 when NSPI was granted additional emissions allowances sufficient to achieve compliance with the Cap-and-Trade program and the FAM interest related to the non-cash accrual was reversed.

7. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and Nova Scotia provincial statutory income tax rate for the following reasons:

millions of dollars	2024	2023
Income before provision for income taxes	\$ 118	\$ 133
Statutory income tax rate	29%	29%
Income taxes, at statutory income tax rate	34	39
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	(77)	(50)
Non-deductible RER penalty	-	3
Other	1	-
Income tax recovery	\$ (42)	\$ (8)

Effective income tax rate	(36%)	(6%)

The following reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of dollars	2024	2023
Current income taxes	\$ (1)	\$ -
Deferred income taxes	(41)	32
Operating loss carryforwards	-	(40)
Income tax recovery	\$ (42)	\$ (8)

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of dollars	2024	2023
Deferred income tax assets:		
Tax loss carryforwards	\$ 191	\$ 305
Asset retirement obligations	56	54
Pension and post-retirement liabilities	36	36
Derivative instruments	16	31
Other	65	34
Total deferred income tax assets before valuation allowance	364	460
Valuation allowance	(10)	(11)
Total deferred income tax assets after valuation allowance	\$ 354	\$ 449
Deferred income tax liabilities:		
PP&E	\$ (934)	\$ (890)
Pension and post-retirement assets	(76)	(37)
Regulatory asset - FAM	-	(115)
Other	(83)	(81)
Total deferred income tax liabilities	\$ (1,093)	\$ (1,123)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax liabilities	\$ (739)	\$ (674)

As at December 31, 2024, NSPI had a net operating loss carryforward of \$615 million (2023 – \$954 million) which expires in 2042 and 2043, investment tax credits of \$1 million (2023 – nil) which expire between 2040 and 2042 and a gross capital loss carryforward of \$51 million (2023 – \$54 million) with an indefinite carryforward period. NSPI has a deferred tax asset of \$181 million relating to the net operating loss carryforward (2023 – \$294 million), a deferred tax asset of \$1 million (2023 – nil) relating to the investment tax credits and a \$10 million deferred tax asset relating to the capital loss carryforward (2023 – \$11 million). A valuation allowance of \$10 million has been recorded as at December 31, 2024 (2023 – \$11 million) related to the capital loss carryforward as realization is uncertain.

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that NSPI is more likely than not to realize all recorded deferred income tax assets, except for the capital loss carryforward noted above. The only valuation allowance recorded as at December 31, 2024 is related to the capital loss carryforward.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of dollars	2024		2023	
Balance, January 1	\$	22	\$	20
Increases due to tax positions related to current year		5		3
Decreases due to tax positions related to a prior year		(2)		(1)
Balance, December 31	\$	25	\$	22

The total amount of unrecognized tax benefits as at December 31, 2024 was \$25 million (2023 – \$22 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was \$10 million (2023 – \$9 million) with \$1 million interest expense recognized in the Consolidated Statement of Income in 2024 (2023 – \$2 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next twelve months as a result of resolving Canada Revenue Agency (“CRA”) audits. A reasonable estimate of any change cannot be made at this time.

NSPI files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. As at December 31, 2024, NSPI’s tax years still open to examination by taxing authorities include 2006 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is \$126 million (2023 – \$126 million), including interest. NSPI has prepaid \$55 million (2023 – \$55 million), of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

Should NSPI be similarly reassessed by the CRA for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Notice of Appeal process is not determinable at this time.

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

	Defined benefit pension and non-pension benefits			
millions of dollars	2024		2023	
Balance, January 1	\$	(78)	\$	(37)
Amounts reclassified to (from) AOCL		70		(41)
Balance, December 31	\$	(8)	\$	(78)

The reclassifications (out of) in to AOCL are as follows:

millions of dollars		2024	2023
	Affected line item in the Consolidated Financial Statements (1)	Amounts reclassified (to) from AOCL	
Amortization of actuarial losses	Other income, net	\$ 1	\$ -
Amounts reclassified to obligations	Pension and post-retirement liabilities	69	(41)
Total reclassifications in to (out of) AOCL for the period		\$ 70	\$ (41)

(1) These AOCL components are included in the computation of net periodic pension cost (refer to note 14 for additional details).

9. RECEIVABLES, NET

As at	December 31	December 31
millions of dollars	2024	2023
Customer accounts receivable – billed	\$ 142	\$ 120
Customer accounts receivable – unbilled	202	196
Total customer accounts receivable	344	316
Allowance for credit losses	(3)	(3)
Customer accounts receivable, net	341	313
Cash collateral position on derivative instruments (note 11)	46	94
Other	30	23
	\$ 417	\$ 430

10. INVENTORY

As at	December 31	December 31
millions of dollars	2024	2023
Fuel	\$ 184	\$ 244
Materials	111	101
	\$ 295	\$ 345

11. DERIVATIVE INSTRUMENTS

Derivative assets and liabilities receiving regulatory deferral consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at	December 31	December 31	December 31	December 31
millions of dollars	2024	2023	2024	2023
Current				
Commodity swaps and forwards	\$ 12	\$ 8	\$ 28	\$ 56
Foreign exchange forwards	22	3	3	2
Total gross current derivatives	34	11	31	58
Impact of master netting agreements with intent to settle net or simultaneously	(6)	(2)	(6)	(2)
Total current derivatives	28	9	25	56
Long-term				
Commodity swaps and forwards	12	3	14	21
Foreign exchange forwards	5	-	-	1
Total gross long-term derivatives	17	3	14	22
Impact of master netting agreements with intent to settle net or simultaneously	(1)	(1)	(1)	(1)
Total long-term derivatives	16	2	13	21
Total derivatives	\$ 44	\$ 11	\$ 38	\$ 77

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Regulatory Deferral

NSPI received approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges and certain physical contracts that do not qualify for the NPNS exception. Refer to note 5 for these regulatory deferrals. The Company has recorded the following changes with respect to derivatives receiving regulatory deferral:

For the	Year ended December 31				
millions of dollars					
	2024		2023		
	Commodity swaps and forwards	Foreign exchange forwards	Commodity swaps and forwards	Physical natural gas purchases	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	\$ (25)	\$ 5	\$ (109)	\$ -	\$ (3)
Unrealized gain (loss) in regulatory liabilities	23	33	(63)	(3)	-
Realized gain in regulatory assets	(8)	-	(5)	-	-
Realized loss in regulatory liabilities	4	-	2	-	-
Realized (gain) loss in inventory (1)	12	(8)	4	-	(10)
Realized (gain) loss in fuel for generation and purchased power (2)	42	(6)	(17)	(49)	(4)
Total change in derivative instruments	\$ 48	\$ 24	\$ (188)	\$ (52)	\$ (17)

(1) Realized (gains) losses will be recognized in "Fuel for generation and purchased power" when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable.

Notional Volumes

As at December 31, 2024, the Company had the following notional volumes of commodity swaps and forward and physical natural gas purchase contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	2025 Purchases	2026-2027 Purchases
<i>Commodity swaps and forwards:</i>		
Natural gas (MMBtu)	12	12
Power (MWh)	1	-
Coal (Metric Tonnes)	1	-
<i>Physical natural gas purchases:</i>		
Natural gas (MMBtu)	6	-

As at December 31, 2024, the Company had the following notional volumes of foreign exchange forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2025	2026
Foreign exchange contracts (millions of US dollars ("USD"))	\$ 208	\$ 69
Weighted average rate	1.3361	1.3296
% of USD requirements	50%	17%

NSPI reassesses forecast foreign exchange requirements periodically and will enter into additional hedges or unwind existing hedges, as required.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high-risk accounts.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, recognizes provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2024, the maximum exposure the Company has to credit risk is \$448 million (December 31, 2023 – \$429 million), which includes accounts receivable, and assets related to derivatives net of collateral/deposits.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity prices and foreign exchange. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits/collateral on hand as at December 31, 2024, was \$13 million (December 31, 2023 – \$12 million). The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty when it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements, North American Energy Standards Board agreements and/or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance, and default.

As at December 31, 2024, the Company had \$56 million (December 31, 2023 – \$46 million) in financial assets considered to be past due, which have been outstanding for an average of 70 days. The fair value of these financial assets is \$54 million (December 31, 2023 – \$44 million), the difference of which is included in the allowance for credit losses. These assets relate to accounts receivable from electric revenue.

Concentration Risk

The Company's concentrations of risk as at December 31, consisted of the following:

As at	2024		2023	
	millions of dollars	% of total exposure	millions of dollars	% of total exposure
Receivables, net				
Residential	\$ 206	45%	\$ 183	42%
Commercial	76	16%	63	14%
Industrial	41	9%	45	10%
Other	48	10%	45	10%
Cash collateral	46	10%	94	22%
	417	90%	430	98%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	44	10%	11	2%
	44	10%	11	2%
	\$ 461	100%	\$ 441	100%

Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable" on the Consolidated Balance Sheets. As at December 31, 2024, the Company's cash collateral position was a \$46 million receivable (December 31, 2023 – \$94 million receivable).

Collateral is posted in the normal course of business. Certain of the Company's derivatives could contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization. As at December 31, 2024, the total fair value of these derivatives, in a liability position, was \$38 million (December 31, 2023 – \$77 million).

12. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 – Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 – Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 – Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.

- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2024 Total
Assets				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 15	\$ 2	\$ -	\$ 17
Foreign exchange forwards	-	27	-	27
Total assets	15	29	-	44
Liabilities				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	18	17	-	35
Foreign exchange forwards	-	3	-	3
Total liabilities	18	20	-	38
Net (liabilities) assets	\$ (3)	\$ 9	\$ -	\$ 6

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2023 Total
Assets				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 7	\$ 1	\$ -	\$ 8
Foreign exchange forwards	-	3	-	3
Total assets	7	4	-	11
Liabilities				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	43	31	-	74
Foreign exchange forwards	-	3	-	3
Total liabilities	43	34	-	77
Net liabilities	\$ (36)	\$ (30)	\$ -	\$ (66)

The financial liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of long-term debt as follows:

As at millions of dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2024	\$ 3,342	\$ 3,349	\$ -	\$ 3,349	\$ -	\$ 3,349
December 31, 2023	\$ 3,868	\$ 3,821	\$ -	\$ 3,821	\$ -	\$ 3,821

The fair values of long-term debt instruments, classified as Level 2 in the fair value hierarchy, are estimated based on the quoted market price from the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity.

13. PROPERTY, PLANT AND EQUIPMENT

As at millions of dollars	December 31 2024	December 31 2023
Generation	\$ 3,873	\$ 3,746
Transmission	1,276	1,234
Distribution	2,186	2,041
General plant and other	863	835
Total cost	8,198	7,856
Less: Accumulated depreciation	(3,499)	(3,350)
	4,699	4,506
Construction work in progress	275	273
Net book value	\$ 4,974	\$ 4,779

For the year ended December 31, 2024, AFUDC of \$13 million (2023 – \$11 million) was capitalized to “PP&E” on the Consolidated Balance Sheets.

As a result of UARB approved accounting policies and depreciation rates, NSPI recognizes or defers certain costs within “PP&E” that would not otherwise be recognized or deferred in the absence of rate regulation. Cumulative differences between items recognized for rate regulatory purposes and USGAAP, including depreciation rates, AFUDC and overhead costs, cannot be separately determined. The cumulative increase to accretion expense included within accumulated depreciation as at December 31, 2024 was \$1 million (2023 – \$1 million).

There were no asset impairments of these assets for the years ended December 31, 2024 and 2023.

The estimated useful lives, in years, for each major category of PP&E consist of the following:

Generation	32 to 65
Generation - hydro	63 to 131
Generation - wind	25
Transmission	40 to 80
Distribution	14 to 65
General plant and other	5 to 50

The estimated average amortization expense for each of the five succeeding years is \$3 million for land rights and \$28 million for computer software.

14. EMPLOYEE BENEFIT PLANS

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees.

Defined Benefit Plans

The Company maintains contributory defined benefit pension plans which cover approximately 30 per cent of the active workforce. The defined benefit plan pension benefits are determined based on the years of service and average salary at the time the employee terminates employment. The plan provides annual post-retirement indexing equal to the change in the Consumer Price Index up to a stated maximum. The measurement date for the defined benefit pension plan is December 31. Effective November 1, 2014, the defined benefit plan was closed to new entrants.

Other retirement benefit plans (“Non-pension benefit plans”) include the unfunded retirement award plan (which is impacted by expected future salary increases) and contributory health care plan. The unfunded retirement award plan was closed to new entrants effective August 1, 2007.

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans for the years ended December 31 were as follows:

millions of dollars	2024		2023	
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	\$ 1,310	\$ 29	\$ 1,194	\$ 27
Service cost	10	1	8	1
Plan participant contributions	5	-	5	-
Interest cost	59	1	61	2
Benefits paid	(70)	(3)	(67)	(2)
Actuarial losses	10	2	109	1
Balance, December 31	\$ 1,324	\$ 30	\$ 1,310	\$ 29
Change in Plan assets				
Balance, January 1	\$ 1,353	\$ -	\$ 1,248	\$ -
Employer contributions	12	3	11	2
Plan participant contributions	5	-	5	-
Benefits paid	(70)	(3)	(67)	(2)
Actual return on assets, net of expenses	164	-	156	-
Balance, December 31	\$ 1,464	\$ -	\$ 1,353	\$ -
Funded Status, end of year	\$ 140	\$ (30)	\$ 43	\$ (29)

The actuarial losses recognized in the period for the defined benefit pension plans are as a result of losses associated with an updated salary increase assumption, higher than expected indexation, and member experience.

For the years ended December 31 the aggregate financial position for all pension plans where the PBO or, for post-retirement benefit plans, the APBO, exceeds the plan assets is as follows:

millions of dollars	2024		2023	
Plans with PBO/APBO in excess of plan assets	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	\$ 50	\$ 30	\$ 52	\$ 29
Fair value of Plan Assets	5	-	5	-
Funded Status	\$ (45)	\$ (30)	\$ (47)	\$ (29)

Plans with Accumulated Benefit Obligation ("ABO") in excess of Plan assets

The ABO for the defined benefit pension plans was \$1,270 million as at December 31, 2024 (2023 – \$1,260 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of dollars	Defined benefit pension plans	
	2024	2023
ABO	\$ 49	\$ 51
Fair value of Plan Assets	5	5
Funded Status	\$ (44)	\$ (46)

Consolidated Balance Sheets

The amounts recognized in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of dollars	2024		2023	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	\$ (5)	\$ (3)	\$ (5)	\$ (3)
Long-term liabilities	(40)	(27)	(42)	(26)
Other assets	185	-	90	-
AOCL	11	(3)	83	(5)
Net amount recognized at end of year	\$ 151	\$ (33)	\$ 126	\$ (34)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCL. The following tables summarize the change in AOCL:

millions of dollars	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans		
Balance, January 1, 2024	\$ 83	\$ -
Amortized in current period	(1)	-
Current year reduction from AOCL	(71)	-
Balance, December 31, 2024	\$ 11	\$ -
Non-pension benefits plans		
Balance, January 1, 2024	\$ (5)	\$ -
Current year addition to AOCL	2	-
Balance, December 31, 2024	\$ (3)	\$ -

millions of dollars	2024		2023	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	\$ 11	\$ (3)	\$ 83	\$ (5)
Net amount in AOCL	\$ 11	\$ (3)	\$ 83	\$ (5)

Benefit Cost Components

NSPI's net periodic benefit cost (recovery) as at December 31 included the following:

millions of dollars	2024		2023	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Service cost	\$ 10	\$ 1	\$ 8	\$ 1
Interest cost	59	1	61	2
Expected return on plan assets	(83)	-	(87)	-
Current year amortization of:				
Actuarial losses (gains)	1	-	1	(1)
Total	\$ (13)	\$ 2	\$ (17)	\$ 2

The expected return on plan assets is determined based on the market-related value of plan assets of \$1,428 million as at January 1, 2024 (2023 – \$1,419 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

NSPI's registered defined benefit pension plan employs a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers under the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and maintains the plans' asset allocations within the ranges permitted in the pension plans' investment policy.

NSPI's target asset allocation for 2024 and 2023 was as follows:

Asset Class	2024 Target Range at Market			2023 Target Range at Market		
Short-term securities	0%	to	10%	0%	to	10%
Fixed income	34%	to	49%	34%	to	49%
Equities:						
Canadian	5%	to	15%	7%	to	17%
Non-Canadian (world)	37%	to	61%	35%	to	59%

The investment of the pension assets, including the performance of investment managers, is overseen by the NSPI Management Pension Committee. All pension investments are in accordance with the policies approved by the Board of Directors.

The fair values of investments as at December 31, 2024, by asset category, are as follows:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	\$ -	\$ 12	\$ -	\$ 12	1 %
Equity securities:					
Canadian equity	-	107	-	107	7 %
International equity	-	300	-	300	21 %
Fixed income securities	-	-	48	48	3 %
Open-ended investments measured at Net Asset Value ("NAV") (1)	997	-	-	997	68 %
Total	\$ 997	\$ 419	\$ 48	\$ 1,464	100 %

(1) NAV investments are comprised of open-ended fixed income, short-term investment, Canadian equity and international equity pooled funds. NAV's are calculated at least monthly and the funds honor subscription and redemption activity regularly.

The fair value of investments as at December 31, 2023, by asset category, are as follows:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	\$ -	\$ 9	\$ -	\$ 9	1 %
Equity securities:					
Canadian equity	-	94	-	94	7 %
International equity	-	246	-	246	18 %
Fixed income securities	-	-	45	45	3 %
Open-ended investments measured at NAV (1)	959	-	-	959	71 %
Total	\$ 959	\$ 349	\$ 45	\$ 1,353	100 %

(1) NAV investments are comprised of open-ended fixed income, short-term investment, Canadian equity and international equity pooled funds. NAV's are calculated at least monthly and the funds honor subscription and redemption activity regularly.

Refer to note 12 for more information on the fair value hierarchy and inputs used to measure fair value.

Investments in Emera Incorporated or NSPI

As at December 31, 2024 and 2023, the assets related to the pension funds do not hold any material investments in Emera or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Post-retirement benefit plan assets

There are no assets set aside to pay for the other post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from general accounts as required.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2025	\$ 12	\$ 3
Expected benefit payments		
2025	74	3
2026	77	3
2027	81	3
2028	85	3
2029	90	3
2030 – 2034	516	18

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans as at December 31 included the following:

	2024		2023	
(weighted average assumptions)	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation				
Discount rate - past service	4.63 %	4.34 %	4.63 %	4.62 %
Discount rate - future service	4.72 %	4.50 %	4.62 %	4.63 %
Rate of compensation increase	2.75 - 4.00%	2.75 - 4.00%	2.25 - 4.75%	2.25 - 4.75%
Health care trend - initial (next year)	-	5.86 %	-	6.00 %
- ultimate	-	3.60 %	-	3.60 %
- year ultimate reached	-	2040	-	2040
Benefit cost				
Discount rate - past service	4.63 %	4.62 %	5.17 %	5.14 %
Discount rate - future service	4.62 %	4.63 %	5.19 %	5.16 %
Expected long-term return on plan assets	6.00 %	-	6.25 %	-
Rate of compensation increase	2.25 - 4.75%	2.25 - 4.75%	2.25 - 4.75%	2.25 - 4.75%
Health care trend - initial (current year)	-	6.00 %	-	4.65 %
- ultimate	-	3.60 %	-	3.60 %

The rate of compensation increases for the December 31, 2024, benefit obligation disclosure ranged from 2.75 per cent (age 45 and over) to 4.00 per cent (age 34 and under).

The expected long-term rate of return on plan assets is based on projected real rates of return for the plan's current asset allocation and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined.

The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rates are based on high-quality long-term Canadian corporate bonds, with maturities matching the estimated cash flows from the pension plan for future service and past service.

Defined Contribution Plan

The Company also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2024, was \$7 million (2023 – \$6 million).

15. LEASES

Lessee

NSPI has operating leases for office space, land, telecommunications services and rail cars. NSPI's leases have remaining lease terms of 1 year to 61 years, some of which include options to extend the leases for up to 51 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

As at millions of dollars	Classification	December 31 2024	December 31 2023
Right-of-use asset	Other long-term assets	\$ 20	\$ 21
Lease liabilities:			
Current	Other current liabilities	-	1
Long-term	Other long-term liabilities	21	21
Total lease liabilities		\$ 21	\$ 22

For the year ended December 31, 2024, NSPI has recorded lease expense of \$113 million (2023 – \$120 million) of which \$112 million (2023 – \$119 million) relates to variable costs for power generation facility finance leases recognized in "Fuel for generation and purchased power".

As at December 31, 2024, future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Minimum lease payments	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	43	\$ 48
Less: Imputed interest							27
Total							\$ 21

Additional information related to NSPI's leases for the year ended December 31, 2024 is as follows:

Weighted average remaining lease term	47
Weighted average discount rate - operating leases	2.41%

Lessor

The Company's net investment in direct finance and sales-type leases relates to leases of heat pumps and other equipment.

The net investment in heat pump and other equipment leases consist of the following:

As at millions of dollars	December 31 2024	December 31 2023
Minimum lease payments to be received	\$ 39	\$ 53
Less: Unearned finance lease income	7	12
Net investment in direct finance and sales-type leases	\$ 32	\$ 41
Principal due within one year (included in 'Receivables, net')	\$ 7	\$ 7
Net investment in direct finance and sales-type leases - long-term (included in 'Other long-term assets')	\$ 25	\$ 34

The unearned income related to the direct finance and sales-type leases is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Other expenses, net" on the Consolidated Statements of Income. Customers have the option to purchase the heat pumps and other equipment at the end of the lease term for a nominal fee.

As at December 31, 2024, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Minimum lease payments to be received	\$ 9	\$ 8	\$ 7	\$ 5	\$ 4	\$ 6	\$ 39

16. RELATED PARTY TRANSACTIONS

The Company enters into transactions with Emera Inc. and other subsidiaries or investments of Emera Inc. in the normal course of operations. As at December 31, 2024, related parties include Emera Inc., Brooklyn Power Corporation, Emera Energy Inc., Emera Energy Services, Inc. and NSPML. All related party transactions entered into by NSPI are governed by an Affiliate Code of Conduct approved by the UARB.

Transactions between the Company and its related parties reported in the Consolidated Statements of Income and Consolidated Balance Sheets are as follows:

For the millions of dollars		Year ended December 31
Nature of Service	Presentation	2024 2023
Sales:		
Management and administrative, and other services	OM&G	\$ 19 \$ 15
Rent and other services	Operating revenues	2 2
Purchases:		
Maritime Link assessment (note 5)	Fuel for generation and purchased power	(324) 163
Net purchase of electricity and natural gas	Fuel for generation and purchased power	31 26
Management and administrative, and other services	OM&G	11 11

For the year ended December 31, 2024, the Company issued 0.04 million (2023 – 30.84 million) common shares to Emera for total consideration of \$0.4 million (2023 – \$308.4 million).

As at December 31, 2024, NSPI had \$150 million due to Emera and affiliates (December 31, 2023 – \$123 million).

17. OTHER CURRENT LIABILITIES

As at millions of dollars	December 31 2024	December 31 2023
Accrued charges	\$ 61	\$ 57
Accrued interest on long-term debt	41	41
Carbon tax payable	25	22
Sales taxes payable	11	11
Other	4	1
	\$ 142	\$ 132

18. LONG-TERM DEBT

NSPI's long-term debt includes the issuances detailed below. Medium-term notes are issued under trust indentures at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year. Long-term debt as at December 31 consisted of the following:

millions of dollars	Interest Rate	Maturity	2024	2023
Discount notes (1)	Variable	2029	\$ 177	\$ 323
Bankers' acceptances (2)	Variable	2025	-	398
Revolving credit facility - BESS Project (3)	2.51%	2047	19	-
Medium-term notes				
Series F	8.85%	2025	125	125
Series L	8.30%	2036	60	60
Series M (4)	8.50%	2026	40	40
Series N	7.60%	2097	50	50
Series P	6.28%	2029	40	40
Series R	7.45%	2031	75	75
Series S	6.95%	2033	200	200
Series V	5.67%	2035	150	150
Series W	5.95%	2039	200	200
Series X	5.61%	2040	300	300
Series Y	4.15%	2042	250	250
Series Z	4.50%	2043	300	300
Series AA	3.61%	2045	175	175
Series AB	3.57%	2049	400	400
Series 2020-1	3.31%	2050	300	300
Series 2023-1	4.95%	2032	300	300
Series 2023-2	5.36%	2053	200	200
			\$ 3,165	\$ 3,165
			\$ 3,361	\$ 3,886
Debt issuance costs			(19)	(18)
Amount due within one year			(125)	-
Long-term debt			\$ 3,217	\$ 3,868

(1) Discount notes are backed by a revolving credit facility which matures in 2029.

(2) Banker's acceptances are issued under NSPI's non-revolving term facility. In December 2024, this facility was repaid in full.

(3) NSPI has revolving credit facility to finance the BESS Project. Refer to "Financing Activity" section below for further details.

(4) Notes are extendable until 2056 at the option of the holders.

The Company's total long-term credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity	2024		2023
Revolving credit facility (1)	June 2029	\$	800	\$ 800
Non-revolving term facility	July 2025		-	400
Total		\$	800	\$ 1,200
Less:				
Face value of borrowings under credit facilities			177	725
Letters of credit issued inside the line of credit			12	7
Use of available facilities		\$	189	\$ 732
Available capacity under existing agreements		\$	611	\$ 468

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to \$50 million at prime rate borrowing. Overdraft advances are classified as short-term debt.

Credit Facilities

NSPI can issue up to \$800 million under its commercial paper program, of which the full amount outstanding is backed by the Company's operating credit facility. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

As at December 31, 2024, the revolving credit facility has standby fees of 0.2 per cent calculated on the limit of the revolving credit facility less any outstanding letters of credit. The weighted average interest rate on the outstanding borrowings on the revolving credit facility was 3.88 per cent as at December 31, 2024 (2023 – 5.90 per cent).

Financing Activity

On December 16, 2024, NSPI repaid its \$300 million unsecured non-revolving credit facility set to mature in June 2025.

On June 13, 2024, NSPI entered a non-revolving credit facility to finance BESS Project. NSPI can request funds under the facility quarterly for amounts related to incurred BESS Project costs up to the total commitment of the lesser of \$120 million and 45.06 per cent of the total eligible BESS Project costs over the term of the agreement. The facility will be available until 6 months after completion of the BESS Project, not to exceed May 21, 2027 (the "Availability Period") and matures 20 years following the end of the Availability Period. As at December 31, 2024, NSPI had utilized \$19 million from the facility, which bears interest at 2.51 per cent.

On June 24, 2024, NSPI amended and restated its revolving credit facility, primarily to extend the maturity from December 2027 to June 2029. There were no other material changes in commercial terms from the prior agreement. On the same date, NSPI amended and restated its non-revolving term facility, primarily to extend the maturity from July 2024 to June 2025 and decrease the amount of the facility from \$400 million to \$300 million. There were no other material changes in commercial terms from the prior agreement.

Debt Covenants

NSPI's debt obligations contain covenants related to the amount of debt to capitalization as defined in certain agreements. In addition, other covenants and financial reporting obligations exist. Failure to comply with these covenants could result in an event of default, which if not cured or waived, could result in the acceleration of outstanding debt obligations.

NSPI has debt covenants associated with its credit facilities. As at December 31, 2024 and 2023, NSPI was in compliance with all respective financial covenants related to outstanding debt. NSPI's significant covenant is listed below:

Instrument	Financial Covenant	Requirement/Restriction	As at December 31, 2024
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.70:1	0.61:1

Long-Term Debt Maturities

As at December 31, 2024, long-term debt maturities for each of the next five years and in aggregate thereafter are as follows:

Year of maturity	millions of dollars
2025	\$ 125
2026	40
2027	-
2028	-
2029	217
Greater than 5 years	2,979
Total	\$ 3,361

19. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to the reclamation of land at the Company's thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 are as follows:

millions of dollars	2024	2023
Balance, January 1	\$ 132	\$ 109
Accretion deferred to regulatory asset (included in "PP&E") (1)	-	18
Accretion included in ARO liability	7	7
Liabilities settled	(2)	(2)
Balance, December 31	\$ 137	\$ 132

(1) Differences between accretion expense recognized for rate regulatory purposes and USGAAP, and accretion expense not yet approved by the UARB, are deferred to "PP&E". Deferred amounts are included in the Company's next depreciation study. In Q1 2023, the Company reclassified the cumulative balance of cost of removal collected within accretion expense recognized for rate regulatory purposes to accumulated depreciation.

As at December 31, 2024 and 2023, some of the Company's transmission and distribution assets may have additional conditional AROs which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

20. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2024, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt, interest payment obligations, long-term payables and ARO) for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Purchased power (1)	\$ 244	\$ 229	\$ 320	\$ 320	\$ 321	\$ 3,758	\$ 5,192
Transportation (2)	54	31	21	20	20	137	283
Capital projects	195	55	-	-	-	-	250
Solid fuel supply	240	2	-	-	-	-	242
Maritime Link assessment	201	-	-	-	-	-	201
Long-term service agreements (3)	32	23	12	9	8	12	96
DSM	63	-	-	-	-	-	63
Leases (4)	1	1	1	1	1	43	48
Natural gas supply	12	-	-	-	-	-	12
	\$ 1,042	\$ 341	\$ 354	\$ 350	\$ 350	\$ 3,950	\$ 6,387

(1) Represents NSPI's annual requirement to purchase 100 per cent of electricity production from Independent Power Producers and Community Feed-in Tariff participants over varying contract lengths up to 25 years based on estimated production volumes as well as agreements for the purchase of import power.

(2) Purchasing commitments for transportation of solid fuel and natural gas.

(3) Outsourced management of the Company's computer and communication infrastructure, software maintenance and support, shared service agreements at a co-generation facility, transmission and distribution line construction and maintenance services related to a generation facility and wind operating agreements.

(4) Operating leases for office space, land, telecommunications services, and rail cars.

NSPI has a contractual obligation to pay NSPML, a related party, for the use of the Maritime Link over approximately 38 years from its January 15, 2018, in-service date.

On November 29, 2024, NSPML received UARB approval to collect up to \$197 million from NSPI for the recovery of costs associated with the Maritime Link in 2025, subject to a monthly holdback of up to \$4 million. The approved costs include \$158 million related to the 2025 annual cost assessment and a supplemental assessment of \$39 million as part of the repayment of the federal loan guarantee. For further details on the federal loan guarantee refer to note 5.

B. Legal Proceedings

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

NSPI's activities are subject to a broad range of federal, provincial, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. This includes the federal and provincial governments goals to transition off coal and reach 80 per cent renewable electricity sales by 2030. Capital investment in Nova Scotia's grid will be required to integrate additional renewable energy into the system, while continuing to provide safe, reliable electricity to customers. NSPI is working with both levels of government to determine the appropriate funding in Nova Scotia to facilitate these projects while minimizing costs for customers. Capital investment by NSPI will be dependent on the sources of funding and ownership structures in place to facilitate these investments, therefore, the total impact to NSPI and incremental cost to customers of this clean energy transition is not known at this time.

NSPI estimates its environmental capital spending, excluding AFUDC, based upon present environmental laws and regulations will be approximately \$148 million during fiscal 2025 and is estimated to be \$96 million from 2026 through 2029. Amounts that have been committed to are included in “Capital projects” in the commitments table in note 20. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions.

In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to the Company. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on the Company.

Conformance with legislative and Company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2024.

Polychlorinated Biphenyl Equipment

In response to the Canadian Environmental Protection Act 1999, 2008 Polychlorinated Biphenyl (“PCB”) Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil-filled electrical equipment on its system that fall under the 2008 PCB Regulations Standard by December 31, 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be \$115 million and, as at December 31, 2024, approximately \$92 million (December 31, 2023 – \$81 million) has been spent to date. NSPI has recognized an ARO liability on the balance sheet of \$2 million as at December 31, 2024 (December 31, 2023 – \$3 million) associated with the PCB phase-out program.

D. Principal Financial Risks and Uncertainties

In this section, NSPI describes some of the principal financial risks management believes could materially affect the Company in the normal course of business. Risks associated with derivatives and fair value measurements are discussed further in note 11 and note 12.

NSPI has a business-wide risk management process, monitored by the Board of Directors, to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls. The significant business risks to NSPI are described below, many of which are beyond the Company’s control, and could have a material adverse effect on operations, liquidity or access to or cost of capital, financial position, prospects, and/or results of operations (herein considered a “Material Adverse Effect”).

Regulatory and Political Risk

NSPI is subject to complex legislative and regulatory frameworks that impact matters such as industry, business, rates and cost structures, revenue requirements, allowable ROE, capital structure, rate base and capital investments, depreciation and amortization, operating expenditures, recovery of purchased electricity and fuel costs and other costs, aspects of the operations, siting, planning, construction, operation and decommissioning of electric generation, storage, transmission and distribution facilities and natural gas transportation and distribution systems, service reliability, terms and conditions of service, performance standards, change of control transactions, certain accounting matters and affiliate transactions. NSPI’s is regulated under a cost-of-service model and must obtain regulatory approval to change or add rates and/or riders and there is no assurance in the outcomes or impact of any regulatory process or decision.

If NSPI is unable to recover in a timely manner a material amount of costs or a return on invested capital through regulatory mechanisms or otherwise, is disallowed the recovery of certain costs, is subject to regulatory penalties, is not permitted to make certain capital investments, or is not permitted to invest in or

divest certain utility assets, it could result in a Material Adverse Effect, including valuation impairments. Regulatory lag, the time between the incurrence of costs and the granting of the rates to recover those costs by regulators, may also result in a Material Adverse Effect.

The regulatory framework, process and regulatory decisions may also be adversely affected by changes in government, shifts in government or public policy, legislative changes, regulatory decisions, geopolitical changes, changes in the economic environment, or other factors. Government interference in the regulatory process or regulatory decisions can undermine regulatory stability, predictability, and independence. Any such changes could have a Material Adverse Effect.

Commodity Price Risk

The Company's fuel supply is subject to commodity price risk.

The Company's fuel supply is exposed to broader global market conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to, currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks, such as political instability, conflicts, changes to international trade agreements, tariffs, trade sanctions or embargos.

Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales, any of which could result in a Material Adverse Effect.

General Economic Risk

The Company has exposure to the macro-economic conditions in Nova Scotia. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity, and in turn the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could have a Material Adverse Effect. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

Interest Rate Risk:

NSPI utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk.

The allowed range of ROE will generally follow the direction of interest rates, such that it is likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. The cost of debt is a component of rates and prudently incurred debt costs are recovered from customers.

Interest rates could also be impacted by changes in credit ratings.

As at December 31, 2024, 95 per cent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 17 years.

Inflation Risk:

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates.

E. Guarantees and Letters of Credit

As at December 31, 2024, the Company had \$104 million USD (2023 – \$104 million USD) of guarantees outstanding with terms of varying lengths, all of which are issued on behalf of its subsidiary, NSPEMI.

As at December 31, 2024, the Company had \$7 million USD and \$3 million CAD of letters of credit outstanding (2023 – \$3 million USD and \$3 million CAD).

F. Collaborative Arrangements

For the years ended December 31, 2024 and 2023, the Company has identified the following material collaborative arrangements:

The Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in "OM&G" on the Consolidated Statements of Income.

NSPI is a participant in a 23.3 megawatt ("MW") wind energy project with Renewable Energy Services Ltd. in Point Tupper, Nova Scotia, with NSPI owning 47.4 per cent. In 2024, NSPI recognized \$2 million net expense (2023 – \$2 million) in "Fuel for generation and purchased power".

NSPI is a participant in a 102 MW wind energy project with the South Canoe Development Partnership for South Canoe Wind Farm, in New Ross, Nova Scotia, with NSPI owning 49 per cent. In 2024, NSPI recognized a \$8 million (2023 – \$4 million) net expense in "Fuel for generation and purchased power" and \$3 million (2023 – \$3 million) in "OM&G".

NSPI is a participant in a 13.8 MW wind energy project with the Municipality of the District of Guysborough for Sable Wind Farm, near Canso, Nova Scotia, with NSPI owning 49 per cent. In 2024, NSPI recognized a \$2 million (2023 – \$2 million) net expense in "Fuel for generation and purchased power".

21. REDEEMABLE PREFERRED STOCK

On August 30, 2024, NSPI authorized 800,000 redeemable preferred shares and issued 400,000 redeemable preferred shares ("Series A") at a par value of \$25 per share to finance the Battery Energy Storage System Project. As at December 31, 2024, NSPI has 400,000 redeemable preferred shares outstanding at a par value of \$10 million. Redeemable preferred shares are accounted for as a liability and recorded in "Redeemable preferred stock" on the Consolidated Balance Sheets and the redeemable preferred share dividends are recorded in "Interest expense, net" on the Consolidated Statements of Income.

22. STOCK-BASED COMPENSATION

EMPLOYEE COMMON SHARE PURCHASE PLAN

Eligible employees may participate in Emera's Employee Common Share Purchase Plan ("ECSP"). As of December 31, 2024, the plan allows employees to make cash contributions of a minimum of \$25 to a maximum of \$20,000 per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employee's contributions to the plan.

The plan allows the reinvestment of dividends except where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares (2023 – 7 million common shares).

Compensation cost for shares issued by Emera for the year ended December 31, 2024, to employees of NSPI under the ECSPP was \$2 million (2023 – \$2 million) and is included in “OM&G” on the Consolidated Statements of Income.

SHARE UNIT PLANS

The Company participates in Emera’s DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on an average Emera common share price at the end of the period.

Deferred Share Unit Plan

Under the Directors’ DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors’ fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera’s common shares, the Director’s DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant’s account is calculated by multiplying the number of DSUs in the participant’s account by Emera’s closing common share price on the date the DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When short-term incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera’s common shares, each participant’s DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Unless otherwise determined by the Emera Management Resources and Compensation Committee (“MRCC”), following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant’s account is calculated by multiplying the number of DSUs in the participant’s account by the average of Emera’s stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2024, is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2023	46,995	\$ 48.39	109,501	\$ 46.36
Granted including Dividend Reinvestment Program ("DRIP")	8,017	48.33	16,742	48.77
Exercised	(918)	32.54	N/A	N/A
Transferred	(7,731)	47.32	N/A	N/A
Outstanding as at December 31, 2024	46,363	\$ 48.87	126,243	\$ 46.68

Compensation cost recognized for employee and director DSU for the year ended December 31, 2024 was \$1 million (2023 – nil). Tax benefits realized related to this compensation cost was nil for share units in 2024 and 2023. The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2024 was \$9 million (2023 – \$8 million). Cash payments made during the year ended December 31, 2024 and 2023 associated with the DSU plan were nil.

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. Unless otherwise determined by the MRCC, PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in certain departure scenarios. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2024, is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (millions of dollars)
Outstanding as at December 31, 2023	62,787	\$ 54.96	\$ 3
Granted including DRIP	40,775	48.50	
Exercised	(17,533)	54.66	
Forfeited	(2,524)	50.70	
Transferred	(4,765)	55.69	
Outstanding as at December 31, 2024	78,740	\$ 51.78	\$ 4

Compensation cost recognized for the PSU plan for the year ended December 31, 2024, was \$2 million (2023 – \$1 million). Tax benefits realized related to this compensation cost were nil for share units in 2024 and 2023. Cash payments made during the year ended December 31, 2024 associated with the PSU plan were \$1 million (2023 – \$1 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping cycles, resulting in a cash payment. Unless otherwise determined by the MRCC, RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2023, is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (millions of dollars)
Outstanding as at December 31, 2023	58,204	54.80	\$ 2
Granted including DRIP	39,650	48.48	
Exercised	(15,158)	54.66	
Forfeited	(3,102)	50.88	
Transferred	(4,099)	56.35	
Outstanding as at December 31, 2024	75,495	51.59	\$ 4

Compensation cost recognized for the RSU plan for the year ended December 31, 2024, was \$1 million (2023 – \$1 million). Tax benefits realized related to this compensation cost were nil for share units in 2024 and 2023. Cash payments made during the year ended December 31, 2024, associated with the RSU plan were \$1 million (2023 – \$1 million).

23. SEGMENT INFORMATION

NSPI's consolidated operations represents a single reportable segment. The Company's single operating and reportable segment is in one regulatory environment, geographical region, and revenue is primarily derived from the sale of rate-regulated electricity. The Company's chief operating decision maker is the Company's President and Chief Executive Officer. The Company's net income reported to the Company's chief operating decision maker is consistent with the Consolidated Statements of Income. All operations and PP&E reside in the Province of Nova Scotia, Canada.

24. VARIABLE INTEREST ENTITIES

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

For the year ended December 31, 2024, the Company has not identified any new VIEs.

25. SUBSEQUENT EVENTS

These consolidated financial statements and notes reflect NSPI's evaluation of events occurring subsequent to the balance sheet date through February 21, 2025, the date the financial statements were issued.



Management's Discussion & Analysis

As at February 21, 2025

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Nova Scotia Power Inc. during the fourth quarter of 2024 relative to the same quarter in 2023; for the full year of 2024 relative to 2023 and selected financial information for 2022; and its financial position as at December 31, 2024 relative to 2023. Throughout this discussion, "NSPI" and "Company" refer to Nova Scotia Power Inc. and its consolidated subsidiary NS Power Energy Marketing Incorporated ("NSPEMI").

This discussion and analysis should be read in conjunction with the NSPI annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2024. NSPI follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to NSPI, including the Company's Annual Information Form, can be found on SEDAR+ at www.sedarplus.ca.

NSPI's accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). The rate-regulated accounting policies of NSPI may differ from those used by non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues, and expenses.

All amounts are in Canadian dollars ("CAD"), unless otherwise stated.

FORWARD-LOOKING INFORMATION

This MD&A contains forward-looking information and statements which reflect the current view with respect to the Company's expectations regarding future growth, results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes within the meaning of applicable Canadian securities laws. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecast", "intends", "may", "might", "plans", "projects", "schedule", "should", "targets", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to NSPI's management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; change in law risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; rate base growth; timing and costs associated with certain capital investments; expected impacts on NSPI of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; climate change risk;

weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, NSPI undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

INTRODUCTION AND STRATEGIC OVERVIEW

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada. NSPI has \$7.1 billion of assets and provides electricity generation, transmission and distribution services to approximately 557,000 customers. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities. To ensure reliability of service, NSPI must maintain a generating capacity greater than firm peak demand. NSPI owns 2,422 Megawatts ("MW") of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind or solar; 7 per cent is petroleum coke ("petcoke") and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP") and community feed in tariff ("COMFIT") participants, which own 533 MW of capacity. This includes IPPs in which NSPI has an ownership interest. NSPI also has rights to 153 MW of Maritime Link capacity, representing Newfoundland and Labrador Hydro's ("NLH", formerly Nalcor Energy) Nova Scotia Block ("NS Block") delivery obligations, which are described further in "Outlook" below. In 2024, NSPI derived 42 per cent of its electric sales from renewable sources and achieved a 61 per cent reduction in generation from solid fuel compared to 2005 levels.

NSPI is working closely with the provincial government to transition off coal and working to reach 80 per cent renewable electricity sales by 2030. These are ambitious goals set by the federal and provincial governments to address climate change. NSPI is committed to achieving these goals, while continuing to provide safe and reliable electricity to customers. For further details on the renewable energy transition, developments related to provincial and federal environmental laws and regulations, and risks around achieving climate-related and environmental legislative requirements refer to the "Outlook – Environmental Legislation and Climate Change" section below.

NSPI is a wholly-owned subsidiary of Emera Incorporated ("Emera"). NSPI holds a 100 per cent investment in NSPEMI, an energy business that purchases and sells electricity and natural gas in the United States of America's energy commodity market.

NSPI is a public utility as defined in the *Public Utilities Act* (Nova Scotia) ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI's approved regulated return on equity ("ROE") range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent of approved rate base.

NSPI has a UARB approved Fuel Adjustment Mechanism (“FAM”) allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods. Refer to note 5 of NSPI’s consolidated financial statements as at December 31, 2024 for further details on NSPI’s regulatory mechanisms.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect the demand for energy and cost of service. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

OUTLOOK

Operations

NSPI’s earnings are most directly impacted by the range of ROE and capital structure approved by the UARB, the prudent management and approved recovery of operating costs, electric sales volumes, weather, the approved recovery of regulatory deferrals and the timing and amount of capital investment.

NSPI expects earnings in 2025 to be consistent with 2024 and anticipates earning below its allowed ROE range in 2025. Sales volumes are expected to be higher in 2025 than 2024. Capital investment for 2025, including allowance for funds used during construction (“AFUDC”), is expected to be approximately \$480 million (2024 – \$487 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Climate Change

NSPI is subject to environmental laws and regulations as set by both the Government of Canada and the Province of Nova Scotia (the “Province”). NSPI continues to work with both levels of government to comply with these laws and regulations, to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated compliance will be recoverable under NSPI’s regulatory framework. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI’s operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the “Enterprise Risk and Risk Management” section. Recent developments related to climate initiatives and provincial and federal environmental laws and regulations are outlined below.

Clean Electricity Regulations (“CER”):

On December 17, 2024, Environment and Climate Change Canada (“ECCC”) released a finalized version of the CER. The CER establish performance standards to further limit greenhouse gas (“GHG”) emissions from fossil fuel generated electricity starting in 2035 and help facilitate the Government of Canada’s intention of achieving a net-zero electricity grid by 2050. Compliance with the finalized version of the CER is not anticipated to require significant capital investment incremental to achieve the 2030 targets as NSPI’s planned capital investment during this period is driven by the Province’s goals to transition off coal and reach 80 per cent renewable electricity sales by 2030.

Nova Scotia Energy Reform Act:

On April 5, 2024, the Province enacted *Bill 404 - Energy Reform (2024) Act*. The legislation enacted the *Energy and Regulatory Board Act*, which established the Nova Scotia Energy Board (“NSEB”). The NSEB is a new board which will regulate energy and utility entities in Nova Scotia, with a mandate of increased focus on meeting energy transition demands. The legislation also enacts the *More Access to Energy Act*,

which provides for the establishment and phased transition to the Nova Scotia Independent Energy System Operator. NSPI is fully engaged in working with the Province on these initiatives.

Renewable Electricity Regulations (“RER”):

On May 26, 2023, NSPI initiated an appeal, through a proceeding with the UARB, of the \$10 million penalty levied on NSPI by the Province for non-compliance with the RER compliance period ending in 2022. The hearing for the matter is currently scheduled for June 2025.

Tax Legislation

On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the excessive interest and financing expenses limitation (“EIFEL”) regime, which is effective January 1, 2024. EIFEL applies to limit a company’s net interest and financing expense deduction to no more than 30 per cent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely. There are no impacts required to be recognized in the Company’s financial statements as at December 31, 2024.

DEVELOPMENTS

Operations

Federal Loan Guarantee:

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSP Maritime Link Inc. (“NSPML”) and the Province of Nova Scotia on terms and conditions for a federal loan guarantee of \$500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On September 25, 2024, NSPI and NSPML filed applications with the UARB related to the federal loan guarantee. On November 29, 2024, the UARB approved NSPML’s application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and to increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance. On February 18, 2025, the UARB approved NSPI’s application to increase 2025 fuel rates to service the incremental NSPML debt.

Storm Rider:

On December 2, 2024, the UARB approved the recovery of \$24 million of major storm restoration and incremental financing costs deferred to NSPI’s storm rider in 2023 to be recovered over a 12-month period beginning on January 1, 2025.

Hurricane Fiona:

On June 27, 2024, the UARB approved the deferred recognition of \$25 million in incremental operating costs incurred during the Hurricane Fiona storm restoration efforts in September 2022. Following the UARB approval, the \$25 million was reclassified to “Regulatory assets” from “Other long-term assets”. The UARB also directed NSPI to reclassify \$10 million of undepreciated costs related to assets retired because of Hurricane Fiona to “Regulatory assets” from “Property, plant and equipment” on the Consolidated Balance Sheets. NSPI began amortizing both of these regulatory assets over a 10-year period beginning on July 1, 2024.

Battery Energy Storage System Project ("BESS Project"):

On June 13, 2024, the UARB approved \$238 million of capital investment, including AFUDC, for the BESS Project. The project is comprised of three 50 MW, four-hour battery facilities. Two facilities are anticipated to be in-service in late 2025 and the third facility in 2026.

FAM Application:

On April 17, 2024, the UARB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the \$117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

Appointments

Effective May 8, 2024, Vivek Sood joined the NSPI Board of Directors. Mr. Sood retired as Executive Vice President, Related Businesses from Sobeys Inc in 2024, and is a current member of Crombie REIT's Board of Trustees.

FINANCIAL REVIEW OF 2024

Consolidated Statements of Income

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Operating revenues	\$ 479	\$ 439	\$ 1,855	\$ 1,671
Fuel for generation and purchased power	(216)	234	509	777
FAM and other deferrals	436	(63)	350	(98)
Operating, maintenance and general ("OM&G")	95	104	350	350
Demand-side management ("DSM")	15	13	58	50
Provincial grants and taxes	12	11	48	45
Depreciation and amortization	73	70	282	276
Total operating expenses	415	369	1,597	1,400
Income from operations	64	70	258	271
Other income, net	(7)	(10)	(28)	(32)
Interest expense, net	42	42	168	170
Income before provision for income taxes	29	38	118	133
Income tax recovery	(42)	(2)	(42)	(8)
Net income	\$ 71	\$ 40	\$ 160	\$ 141

Highlights of the significant changes are summarized in the following table:

For the millions of dollars	Three months ended December 31		Year ended December 31	
Net income – 2023	\$	40	\$	141
Increased operating revenues (refer to "Operating Revenues" section for explanation)		40		184
Decreased fuel for generation and purchased power (refer to "Fuel for Generation and Purchased Power" section for explanation)		450		268
Decreased FAM and other deferrals (refer to note 5 of NSPI's consolidated financial statements as at December 31, 2024 for explanation)		(499)		(448)
Increased DSM expense due to higher program costs		(2)		(8)
Increased income tax recovery primarily due to the utilization of tax loss carryforwards offset to a deferred income tax regulatory liability, partially offset by decreased tax deductions in excess of accounting depreciation related to property, plant and equipment		40		34
Other		2		(11)
Net income – 2024	\$	71	\$	160

Operating Revenues

NSPI's operating revenues include sales of electricity and other services as summarized in the following table:

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Electric revenues	\$ 467	\$ 430	\$ 1,813	\$ 1,633
Other revenues	12	9	42	38
Operating revenues	\$ 479	\$ 439	\$ 1,855	\$ 1,671

Electric Revenues

NSPI's electric revenues are affected by rates approved by the UARB and electric sales volumes. NSPI's electric revenues include revenues related to the recovery of fuel costs and non-fuel costs. The FAM allows NSPI to recover all prudently incurred fuel and certain fuel-related costs and consequently, revenues related to the recovery of fuel costs do not have a material impact on NSPI's net income.

Electric sales volumes are primarily driven by weather, number of customers, customer usage, general economic conditions, and DSM activities. Residential and commercial electricity sales are seasonal, with the first quarter historically generating the highest sales, reflecting colder weather and fewer daylight hours in the winter season.

NSPI's residential customers include individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric customers consist primarily of municipal electric utilities, users of street and area lighting services, and export energy customers.

Electric Sales Volumes

For the Gigawatt hours ("GWh")	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Residential	1,343	1,314	5,096	4,986
Commercial	763	764	3,046	3,053
Industrial	569	527	2,217	2,164
Other	57	60	222	239
Total	2,732	2,665	10,581	10,442

Electric Revenues

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Residential	\$ 260	\$ 239	\$ 997	\$ 910
Commercial	128	119	499	463
Industrial	69	62	276	219
Other	10	10	41	41
Total	\$ 467	\$ 430	\$ 1,813	\$ 1,633

Highlights of the changes in electric revenues are summarized in the following table:

For the millions of dollars	Three months ended December 31		Year ended December 31	
Electric revenues – 2023	\$	430	\$	1,633
Increased electricity pricing effective January 1, 2024		28		118
Increased industrial revenue due to 2023 including changes in fuel cost recovery methodology for an industrial customer (refer to note 5 of NSPI's consolidated financial statements as at December 31, 2024 for further details)		-		51
Other		9		11
Electric revenues – 2024	\$	467	\$	1,813

Fuel for Generation and Purchased Power

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet. NSPI brings the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place, and the NS Block of energy, including the Supplemental Energy Block, which carries no additional fuel cost outside of the UARB approved annual assessments paid NSPML for the use of the Maritime Link. Generation mix may also be affected by plant outages, carbon pricing programs, including the Nova Scotia Output-Based Pricing System ("OBPS"), availability of renewable generation, including the NS Block, plant performance, and compliance with environmental regulations.

The high availability and capability of thermal generating stations continues to play a role in providing reliable energy to customers while NSPI is transitioning to more renewable generation. In 2024, thermal plant availability was 82 per cent compared to 83 per cent in 2023 and a four-year average of 81 per cent. The four-year average availability is in line with industry comparisons.

Production volumes by fuel type and average fuel cost are summarized in the following table:

For the GWh (except as indicated)	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Coal	976	764	3,347	3,086
Natural gas	516	489	2,317	1,946
Purchased power	118	203	620	881
Petcoke	40	119	374	553
Oil	64	8	132	145
Total non-renewables	1,714	1,583	6,790	6,611
Purchased power - IPP, COMFIT and imports	608	459	2,086	1,799
NS Block	444	510	1,378	1,452
Wind, hydro and solar	151	316	932	1,149
Biomass	48	16	140	128
Total renewables	1,251	1,301	4,536	4,528
Total production volumes	2,965	2,884	11,326	11,139
Average fuel cost in dollars per MWh (1)(2)(3)	\$ (73)	\$ 81	\$ 45	\$ 70

(1) "MWh" refers to Megawatt hour

(2) In Q4 2024, NSPI received refund of previous NSPML assessment payments, resulting in \$486 million over-recovery of fuel costs. For further details, refer to the "Developments" section above.

(3) In Q1 2023, NSPI recorded a reversal of Nova Scotia Cap-and-Trade Program compliance costs, resulting in a \$166 million under-recovery of fuel costs. For further details refer to note 5 of NSPI's consolidated financial statements as at December 31, 2024.

Average fuel costs per MWh decreased significantly in Q4 2024 compared to Q4 2023, primarily due to a refund of previous NSPML assessment payments. For further details refer to the "Developments" section above. Lower commodity pricing driven primarily by changes in solid fuel also contributed to decreased costs. These decreases were partially offset by an unfavourable generation mix driven by decreased generation from hydro assets, lower delivery of the NS Block and increased renewable purchased power.

Average fuel costs per MWh decreased in 2024 compared to 2023 primarily due to a refund of previous NSPML assessment payments. For further details refer to the "Developments" section above. This decrease was partially offset by the Q1 2023 reversal of Nova Scotia Cap-and-Trade program compliance costs. An unfavourable generation mix also increased costs driven by decreased generation from NSPI renewable assets, increased thermal generation, and increased purchased power.

Highlights of the changes are summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
Fuel for generation and purchased power – 2023	\$ 234	\$ 777
2023 Nova Scotia Cap-and-Trade Program provision reversal (1)	-	166
Change in generation mix	38	53
Increased sales volumes	6	17
Decreased commodity prices	(7)	(15)
Refund of previous NSPML assessment payments (2)	(486)	(486)
Other	(1)	(3)
Fuel for generation and purchased power – 2024	\$ (216)	\$ 509

(1) In Q1 2023, the Province provided NSPI with additional emissions allowances sufficient to achieve compliance with the 2019 through 2022 Nova Scotia Cap-and-Trade Program compliance period and the accrued compliance costs related to the expected purchase of emissions credits were reversed, resulting in a fuel cost recovery of \$166 million.

(2) In Q4 2024, NSPI received a refund of previous NSPML assessment payments. For further details refer to the “Developments” section.

FAM and FAM Regulatory Deferral

NSPI has a UARB approved FAM, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

On September 25, 2024, NSPI and NSPML filed applications with the UARB related to the federal loan guarantee. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance as a refund of a portion of previous NSPML assessment payments. For further details, refer to the “Developments” section.

On April 17, 2024, the UARB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. For further details, refer to the “Developments” section.

Pursuant to the FAM Plan of Administration, NSPI’s fuel costs are subject to independent audit. On February 21, 2024, the UARB’s decision on the FAM audit findings and recommendations relating to fiscal 2020 and 2021 were publicly released and included one disallowance. The disallowance of \$3 million was recorded in Q1 2024 in “FAM and other deferrals” with the associated interest expense of \$1 million recorded in “Interest expense, net”. The total \$4 million was returned to customers through the FAM.

On July 5, 2024, the FAM audit results for fiscal 2022 and 2023 were publicly released and filed with the UARB. A UARB regulatory process is in progress and a hearing will be held in March 2025.

Refer to note 5 of NSPI’s consolidated financial statements as at December 31, 2024 for details of the FAM regulatory asset and associated regulatory matters.

Provincial Grants

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

Income Taxes

In 2024, NSPI was subject to a statutory corporate income tax rate of 29 per cent (2023 – 29 per cent). In 2024, NSPI's effective tax rate was (36 per cent) (2023 – (6 per cent)) primarily due to deferred income taxes on regulated income recorded as regulated assets and regulated liabilities.

Consolidated Balance Sheet Highlights

Significant changes in the Consolidated Balance Sheets between December 31, 2024 and December 31, 2023 include:

millions of dollars		Increase (Decrease)	Explanation
Assets			
Cash	\$	(78)	Decreased due to timing of receipts
Inventory		(50)	Decreased due to lower volumes of fuel inventory and lower weighted average cost, partially offset by higher volumes of materials inventory
Derivative instruments (current and long-term)		33	Increased due to higher commodity prices, and weakening of the CAD dollar compared to the United States dollar ("USD"), partially offset by settlement of derivative instruments
Regulatory assets (current and long-term)		(258)	Decreased deferrals related to FAM (refer to note 5 of NSPI's consolidated financial statements as at December 31, 2024 for explanation) and derivative instruments, partially offset by increased deferrals related to deferred income tax regulatory asset and Hurricane Fiona costs
Pension and post-retirement assets (current and long-term)		95	Increased due to investment returns, partially offset by benefit payments net of contributions, pension indexation and unfavorable changes in actuarial assumptions
Property, plant and equipment, net of accumulated depreciation		195	Increased due to capital investment, partially offset by depreciation
Other assets (current and long-term)		(32)	Decreased due to reclassification of Hurricane Fiona costs to regulatory assets
Liabilities and Equity			
Long-term debt (including current portion)	\$	(526)	Decreased due to net repayments under committed credit facility
Due to related parties (current and long-term)		27	Increased due to timing of payments
Derivative instruments (current and long-term)		(39)	Decreased due to higher commodity prices and settlements of derivative instruments
Regulatory liabilities (current and long-term)		85	Increased deferrals related to FAM (refer to note 5 of NSPI's consolidated financial statements as at December 31, 2024 for explanation) and derivative instruments
Deferred income taxes		65	Increased due to the utilization of tax loss carryforwards, tax deductions in excess of accounting depreciation related to property, plant and equipment and changes in pension and post-retirement assets and liabilities, partially offset by a decrease in FAM regulatory asset
Accumulated other comprehensive loss		(70)	Decreased due to investment returns, partially offset by pension indexation and unfavorable changes in actuarial assumptions
Retained earnings		160	Increased due to net income

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash primarily through the generation, transmission and distribution of electricity. NSPI's customer base is diversified by both sales volumes and rates among customer classes. Circumstances that could affect the Company's ability to generate cash include changes to global macroeconomic conditions, downturns in NSPI's markets, impact of fuel commodity price changes on collateral requirements and timely recoveries of fuel costs from customers, the loss of one or more large customers, regulatory decisions affecting customer rates, the recovery of regulatory assets, the accelerated payment of regulatory liabilities, changes in environmental legislation, political interference in the regulatory process, continued access to an investment grade credit rating and changes in weather patterns.

NSPI's future liquidity and capital needs will be predominantly for working capital requirements, ongoing rate base investment and debt servicing. In 2025, NSPI expects to invest approximately \$480 million, including AFUDC, primarily in capital projects required to support power system reliability and reliable service for customers.

NSPI has access to a \$800 million syndicated revolving bank line of credit with \$611 million available as at December 31, 2024. For further details, refer to the "Debt Management" section.

Consolidated Cash Flow Highlights

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2024 and 2023 include:

millions of dollars	2024	2023	Change
Cash, beginning of year	\$ 78	\$ 2	\$ 76
Provided by (used in):			
Operating cash flow before change in working capital	831	278	553
Change in working capital	88	(394)	482
Operating activities	919	(116)	1,035
Investing activities	(483)	(449)	(34)
Financing activities	(514)	641	(1,155)
Cash, end of year	\$ -	\$ 78	\$ (78)

Cash Flow from Operating Activities

Net cash provided by operating activities increased \$1,035 million to \$919 million in 2024 compared to net cash used in operating activities of \$116 million in 2023.

Operating cash flow before change in working capital increased \$553 million primarily due to decreased fuel for generation and purchased power largely driven by a \$486 million refund of previous NSPML assessment payments, partially offset by the reversal of the Nova Scotia Cap-and-Trade Program provision in 2023 (offset below in working capital), increased electric revenues due to increased electricity pricing, and changes in the Fuel Cost recovery methodology for an industrial customer in 2023 (offset below in working capital), and proceeds of \$117 million from the FAM regulatory asset sale in April 2024. For further details on the refund of previous NSPML assessment payments refer to the "Developments" section.

Changes in working capital increased cash flows by \$482 million primarily due to changes in the cash collateral position on derivative instruments, the reversal of the Nova Scotia Cap-and-Trade Program provision in 2023 (offset above in operating cash flow), changes in fuel inventory, and accounts payable. This is partially offset by changes in accounts receivable (offset above in operating cash flow).

Cash Flow used in Investing Activities

Net cash used in investing activities increased \$34 million to \$483 million in 2024 compared to \$449 million in 2023 due to higher capital investment.

Cash Flow from Financing Activities

Net cash used in financing activities increased \$1,155 million to \$514 million in 2024 compared to net cash provided by financing activities of \$641 million in 2023 primarily due to lower proceeds from long-term debt, higher net repayments under committed credit facilities in 2024 compared to 2023, and issuance of common stock in 2023.

Working Capital

As at December 31, 2024, NSPI's working capital decreased to \$468 million from \$553 million in 2023 primarily due to changes in inventory, changes in cash collateral positions on derivative instruments, and changes in accounts payable, partially offset by changes in accounts receivable.

NSPI's future liquidity and capital needs will be predominately for working capital requirements, capital investment, dividends and debt servicing. Working capital is financed through internally generated cash flows and short-term credit facilities. The Company's expected future cash flows, credit facilities and continued access to debt capital markets for long-term financing is expected to be sufficient to meet the Company's requirements.

Contractual Obligations

As at December 31, 2024, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Purchased power (1)	\$ 244	\$ 229	\$ 320	\$ 320	\$ 321	\$ 3,758	\$ 5,192
Long-term debt (2)	125	40	-	-	217	2,979	3,361
Interest payment obligations (3)	164	159	155	155	151	1,906	2,690
Transportation (4)	54	31	21	20	20	137	283
Asset retirement obligations	3	-	-	-	-	302	305
Capital projects	195	55	-	-	-	-	250
Solid fuel supply	240	2	-	-	-	-	242
Maritime Link assessment	201	-	-	-	-	-	201
Long-term service agreements (5)	32	23	12	9	8	12	96
Pension and post-retirement obligations (6)	11	12	12	12	14	34	95
DSM	63	-	-	-	-	-	63
Leases (7)	1	1	1	1	1	43	48
Natural gas supply	12	-	-	-	-	-	12
	\$ 1,345	\$ 552	\$ 521	\$ 517	\$ 732	\$ 9,171	\$ 12,838

(1) Represents NSPI's annual requirement to purchase 100 per cent of electricity production from IPPs and COMFIT participants over varying contract lengths up to 25 years based on estimated production volumes as well as agreements for the purchase of import power.

(2) NSPI's discount notes are backed by a revolving credit facility which matures in 2029.

(3) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as at December 31, 2024.

(4) Purchasing commitments for transportation of solid fuel and natural gas.

(5) Outsourced management of the Company's computer and communication infrastructure, software maintenance and support, shared service agreements at a co-generation facility, transmission and distribution line construction and maintenance services related to a generation facility and wind operating agreements.

(6) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans, plus the estimated costs of further benefit accruals contracted under the Company's Collective Bargaining Agreement only and estimated benefit payments related to other unfunded benefit plans.

(7) Operating leases for office space, land, telecommunications services, and rail cars.

NSPI has a contractual obligation to pay NSPML, a related party, for the use of the Maritime Link over approximately 38 years from its January 15, 2018, in-service date.

On November 29, 2024, NSPML received UARB approval to collect up to \$197 million from NSPI for the recovery of costs associated with the Maritime Link in 2025, subject to a monthly holdback of up to \$4 million. The approved costs include \$158 million related to the 2025 annual cost assessment and a supplemental assessment of \$39 million as part of the repayment of the federal loan guarantee. For further details on the federal loan guarantee, refer to the "Developments" section.

Capital Investment

Forecast 2025 and actual 2024 and 2023 capital investment, including AFUDC, is shown below:

millions of dollars	2025 Forecast	2024 Actual	2023 Actual
Distribution	\$ 140	\$ 175	\$ 148
Generation	117	151	147
Transmission	184	107	98
General plant and other	39	54	58
Total	\$ 480	\$ 487	\$ 451

Debt Management

NSPI has access to a syndicated revolving bank line of credit. NSPI also has an active commercial paper program for up to \$800 million, of which the full amount outstanding is backed by the Company's operating credit facility. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable. As at December 31, 2024, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Credit Facility	Utilized	Available Capacity
Revolving credit facility	June 2029	\$ 800	\$ 189	\$ 611

NSPI has debt covenants associated with its credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at December 31, 2024. NSPI's significant covenant is listed below:

Instrument	Financial covenant	Requirement/Restriction	Calculation as at December 31, 2024
		Less than or equal to	
Syndicated credit facility	Debt to capital ratio	0.70:1	0.61:1

Financing Activity

On December 16, 2024, NSPI repaid its \$300 million unsecured non-revolving credit facility set to mature in June 2025.

On June 13, 2024, NSPI entered a non-revolving credit facility to finance the BESS Project. NSPI can request funds under the facility quarterly for amounts related to incurred BESS Project costs up to the total commitment of the lesser of \$120 million and 45.06 per cent of the total eligible BESS Project costs over the term of the agreement. The facility will be available until 6 months after completion of the BESS Project, not to exceed May 21, 2027 (the "Availability Period") and matures 20 years following the end of the Availability Period. As at December 31, 2024, NSPI had utilized \$19 million from the facility, which bears interest at 2.51 per cent.

On June 24, 2024, NSPI amended and restated its revolving credit facility, primarily to extend the maturity from December 2027 to June 2029. There were no other material changes in commercial terms from the prior agreement. On the same date, NSPI amended and restated its non-revolving term facility, primarily to extend the maturity from July 2024 to June 2025 and decrease the amount of the facility from \$400 million to \$300 million. There were no other material changes in commercial terms from the prior agreement.

As at December 31, 2024, 95 per cent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 17 years.

Credit Ratings

On December 20, 2024, DBRS affirmed its BBB (high) rating and stable trend for NSPI.

On January 22, 2025, S&P Global Ratings affirmed its BBB- issuer rating and revised its outlook to stable from negative.

Share Capital

For the year ended December 31, 2024, the Company issued 0.04 million (2023 – 30.8 million) common shares to Emera for total consideration of \$0.4 million (2023 – \$308.4 million). As at December 31, 2024, NSPI had 173.5 million common shares issued and outstanding (2023 – 173.4 million common shares).

PENSION FUNDING

For funding purposes, NSPI determines required contributions to its registered defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a five-year period. The cash required in 2025 for defined benefit pension plans is expected to be \$12 million (2024 – \$12 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

NSPI's registered defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

NSPI's projected contributions to the defined contribution pension plans are \$8 million for 2025 (2024 – \$7 million).

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI was appointed to manage and administer a portfolio of defeasance securities. The securities provide principal and interest streams to match the related defeased debt of NSPC, which as at December 31, 2024, totaled \$200 million (2023 – \$200 million).

The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

Under the privatization agreements, NSPI administers the defeasance cash flows and obligations pursuant to a Management and Administration Agreement. The NSPFC bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement and therefore, from time to time, if any cash accumulates in the NSPFC bank account it is available until that cash is required to service the defeased NSPC debt.

Guarantees and Letters of Credit

As at December 31, 2024, the Company had \$104 million US Dollars ("USD") (2023 – \$104 million USD) of guarantees outstanding with terms of varying lengths, all of which are issued on behalf of NSPI's subsidiary, NSPEMI.

As at December 31, 2024, the Company had \$7 million USD and \$3 million CAD of letters of credit outstanding (2023 – \$3 million USD and \$3 million CAD).

TRANSACTIONS WITH RELATED PARTIES

The Company enters into transactions with Emera Inc. and other subsidiaries or investments of Emera Inc. in the normal course of operations. As at December 31, 2024, related parties include Emera Inc., Brooklyn Power Corporation, Emera Energy Inc., Emera Energy Services, Inc. and NSPML. All related party transactions entered into by NSPI are governed by an Affiliate Code of Conduct approved by the UARB.

Transactions between the Company and its related parties reported in the Consolidated Statements of Income and Consolidated Balance Sheets are as follows:

For the millions of dollars			Year ended December 31	
Nature of Service	Presentation		2024	2023
Sales:				
Management and administrative, and other services	OM&G	\$	19	\$ 15
Rent and other services	Operating revenues		2	2
Purchases:				
Maritime Link assessment (note 5)	Fuel for generation and purchased power		(324)	163
Net purchase of electricity and natural gas	Fuel for generation and purchased power		31	26
Management and administrative, and other services	OM&G		11	11

For the year ended December 31, 2024, the Company issued 0.04 million (2023 – 30.84 million) common shares to Emera for total consideration of \$0.4 million (2023 – \$308.4 million).

As at December 31, 2024, NSPI had \$150 million due to Emera and affiliates (December 31, 2023 – \$123 million).

ENTERPRISE RISK AND RISK MANAGEMENT

NSPI has a business-wide risk management process which is monitored by the Board of Directors, and also reviewed with the Emera Enterprise Risk Management Committee to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls.

The significant business risks to NSPI are described below, many of which are beyond the Company's control, and could have a material adverse effect on operations, liquidity or access to or cost of capital, financial position, prospects, and/or results of operations (herein considered a "Material Adverse Effect"). The nature of risk is such that no such list is comprehensive, and the actual effect of any of the risks discussed could be materially different from what is described below. Additionally, other risks not presently known may arise, risks not currently considered material may become material in the future, or two or more risks which are not themselves material, could together be material.

Regulatory and Political Risk

NSPI is subject to complex legislative and regulatory frameworks that cover material aspects of their businesses. These frameworks influence key factors such as rates and cost structures, revenue requirements, allowed ROEs, capital structures, rate base and capital investments, and the recovery of purchased electricity and fuel costs and other costs. Regulators also review the prudence of costs and make other decisions that can impact customer rates and the reliability of service. NSPI's is regulated

under a cost-of-service model and must obtain regulatory approvals for material aspects of their businesses, including changing or adding rates and/or riders. Such approvals often require public hearing proceedings involving numerous stakeholders, and there is no assurance in the outcomes or impact of any regulatory process or decision.

If NSPI is unable to recover in a timely manner a material amount of costs or a return on invested capital through regulatory mechanisms or otherwise, is disallowed the recovery of certain costs, is subject to regulatory penalties, is not permitted to make certain capital investments, or is not permitted to invest in or divest certain utility assets, it could result in a Material Adverse Effect, including valuation impairments. Regulatory lag, the time between the incurrence of costs and the granting of the rates to recover those costs by regulators, may also result in a Material Adverse Effect.

Aspects of the acquisition, ownership, operations, siting, planning, construction, and decommissioning of electric generation, storage, transmission and distribution facilities are also subject to regulatory processes and approvals of regulators, government departments and agencies, and other third parties. The failure to obtain, maintain, and renew such approvals or significant changes in the terms and conditions thereof could have a Material Adverse Effect.

The regulatory framework, process and regulatory decisions may also be adversely affected by changes in government, shifts in government or public policy, legislative changes, regulatory decisions, geopolitical changes, changes in the economic environment, or other factors. Government interference in the regulatory process or regulatory decisions can undermine regulatory stability, predictability, and independence. Any such changes could have a Material Adverse Effect.

Change in Law Risk

The Company is also exposed to changes in the political environment and leadership, changes in law or regulations, changes to governmental policies, trade disputes, and the imposition of tariffs, any of which may impact the Company's businesses, the markets for energy and inputs thereto, or general economic conditions, and which may result in a Material Adverse Effect. This may include initiatives regarding deregulation or restructuring of the energy industry, which may result in increased competition, and increased or unrecovered costs

NSPI cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or the resulting operating or compliance costs or other impacts. It may be difficult for NSPI to respond in an effective and timely manner to such future legislative, policy or regulatory changes.

Changes in Environmental Legislation

NSPI is subject to extensive regulation by federal, provincial and municipal authorities regarding environmental matters; primarily related to its utility operations. This includes laws, regulations and policies relating to GHG emissions, renewable energy standards, climate change, air quality, water quality and usage, waste management, wastewater discharges, soil quality, aquatic and terrestrial habitats, hazardous waste, health, endangered species, and wildlife mortality.

Both the Province and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province has established targets with respect to the percentage of renewable energy in NSPI's generation mix and reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. The Government of Canada has also enacted regulations imposing emissions standards on coal-fired generation that would effectively require the decommissioning of such facilities. While Nova Scotia is exempted from such regulations through 2029, there is no guarantee that such exemption will continue into the future. Failure to meet such goals by 2030 or comply with applicable legislation or regulation could result in a Material Adverse Effect. NSPI

continues to work with both the provincial and federal governments on measures to seek to address their carbon reduction goals.

Per- and polyfluoroalkyl substances (“PFAS”):

PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. The Company does not manufacture PFAS but because these emerging contaminants of concern are so ubiquitous in products and the environment, it may impact NSPI's operations. Changes in environmental laws and regulations related to PFAS could result in new costs or obligations for investigation and cleanup and change the Company's strategy for land acquisition for projects and could result in a Material Adverse Effect.

Greenhouse Gas Emissions:

NSPI is subject to GHG emission caps for the 2010 through 2030 period as outlined in the “Nova Scotia Greenhouse Gas Regulations”, and further updated by Order in Council in 2013. The emission cap reduces from 10 megatonnes in 2010 to 4.5 megatonnes in 2030. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Pursuant to an Equivalency Agreement entered into between the Province and the Government of Canada in 2014 and renewed through 2029, these provincial regulations have been deemed equivalent to, and have exempted Nova Scotia from the application of federal GHG emissions regulations which would effectively require the retirement or conversion of coal-fired electricity generating units by the earlier of 50 years from commissioning or 2030. The Equivalency Agreement can be renewed by mutual agreement through 2029, though there is no guarantee that it will be renewed or remain in force in the future. Over the decade, NSPI will work to comply with the decreasing emission caps through a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

The “Pan-Canadian Framework on Clean Growth and Climate Change” under the “Greenhouse Gas Pollution Pricing Act” put in place the legal mechanism for increasing the carbon tax in Canada by \$15 per tonne annually and reaching \$170 per tonne by 2030 beginning in 2023. In November 2022, the Province enacted amendments to the “Environment Act” which provided the framework for Nova Scotia to implement an OBPS to comply with these Government of Canada regulations. NSPI registrant under the OBPS.

The “Canadian Net-Zero Emissions Accountability Act” outlines the federal objective of attaining net-zero emissions by 2050. Further, the federal government's “2030 Emission Reduction Plan”, required under the “Canadian Net-Zero Emissions Accountability Act”, introduced the federal intention of attaining a net-zero electricity grid by 2035. On December 17, 2024, ECCC released a finalized version of the Clean Electricity Regulations (CER). The CER establish performance standards to significantly limit GHG emissions from fossil fuel-generated electricity starting in 2035 and help facilitate the Government of Canada's intention of achieving a net-zero electricity grid by the same year. NSPI continues to work with both the provincial and federal governments on measures to address their carbon dioxide reduction goals.

Renewable Energy Regulations:

The Province has established targets with respect to the percentage of renewable energy in NSPI's generation mix. Under the RER, the Company currently has a provincially mandated target of achieving at least 40 per cent of energy sales generated from renewable sources each year from 2020 through 2029. Beginning in 2030, the RER mandates that 80 per cent of electric sales be generated from renewable sources. Further, the Nova Scotia “Environmental Goals and Climate Change Reduction Act” established the goal to phase out coal-fired electricity generation by 2030. NSPI continues to work with both the provincial and federal governments on measures to address generation mix targets.

Air Quality Regulations:

NSPI is subject to emission cap requirements for mercury, SO₂ and nitrogen oxide (“NO_x”) as prescribed in the Regulations. The Regulations limit net mercury emissions to 35 kg per year for the period of 2020

through 2029. Beginning in 2021, new emissions compliance periods for SO₂ and NO_x came into effect, as outlined in the Regulations as follows:

Year	NO_x Caps (tonnes)
2021-2024 ¹	56,000
2025	11,500
2026-2029	44,000
2030	8,800

¹NO_x four-year cap for 2021-2024 is 56 tonnes, with no single year exceeding 14.995 tonnes.

Year	SO₂ Caps (tonnes)
2021-2022	90,000
2023-2024	68,000
2025	28,000
2026-2029	104,000
2030	20,000

NSPI is currently within, or forecasts the ability to meet, the prescribed limits for the current compliance periods. For the compliance periods ending in 2022, NSPI exceeded the prescribed limits for Mercury and SO₂. As per the Regulations, NSPI can compensate for the excess Mercury and SO₂ emissions within the three years following the year of exceedance, by reducing emissions equal to the amount of the excess emissions or can apply for an exemption by the Minister citing “unusual and unavoidable circumstances”. NSPI received a Certificate of Variance from Nova Scotia Environment and Climate Change (NSECC) on Jan 12, 2024, which allows NSPI to recover the excess 2022 sulfur dioxide emissions by end of 2029 as opposed to by the end of 2025. The longer timeframe will enable NSPI to recover the excess emissions with no incremental costs to customers while ensuring a reliable electricity grid.

These and new or revised environmental laws, regulations, policies, or interpretations of those laws, regulations or policies could result in a Material Adverse Effect by, among other things, preventing or delaying the development of energy infrastructure projects, restricting the use or output of certain facilities, requiring the early retirement of coal-fired generation, that could result in stranded costs, limiting the availability or use of certain fuels required for the production of electricity, requiring additional pollution control equipment, changing the nature and timing of capital investments, requiring significant capital investments, imposing operating or other costs associated with compliance including carbon taxes or emissions allowances, or by limiting or eliminating certain operations or rendering such operations uneconomical. Impacts could be more significant in the future as the result of new or revised laws or requirements or stricter or more expansive application of existing environmental laws, regulations and policies. Failure to recover environmental costs in a timely manner through rates may also result in a Material Adverse Effect.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, exposing NSPI to legal or regulatory proceedings, disputes, civil fines, injunctive relief, criminal penalties and other sanctions, which could result in a Material Adverse Effect.

Weather Risk

A Material Adverse Effect may arise from weather seasonal variations impacting energy consumption, as well as severe weather events, changing air temperatures, wildfires and other severe weather conditions that are expected to become more frequent and intense as a result of climate change. Refer to “Climate Change Risk”.

The temperature, seasonal variations, and other weather conditions significantly influence the availability and demand for electricity, the price of energy commodities, such as fuel, and the production of electricity

at power generation facilities. For example, NSPI could see lower sales in winter months if temperatures are warmer than expected.

Severe weather events or conditions such as hurricanes, floods, storm surge, tornadoes, droughts, fires, extreme temperatures, snow or ice storms, and other natural disasters create a risk of physical damage to the Company's assets and a risk of extended service outages or fuel supply disruptions. For example, high winds can cause widespread damage to transmission and distribution infrastructure, solar generation, and wind-powered generation. Substantially all of the Company's fossil fueled generation assets are located at or near coastal sites and, as such, are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding.

Severe weather events or conditions could reduce revenues and require the Company to incur additional costs, such as repair and replacement costs, costs of replacement power and fuel, increased insurance costs, and the need to access additional financing sources. These could result in a Material Adverse Effect if not resolved or mitigated in a timely and efficient manner through insurance or regulatory cost recovery. This risk to transmission and distribution facilities is typically not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves, or after the fact through the establishment of regulatory assets. Recovery is not assured, is subject to prudence review, and may be subject to delay resulting in increased debt and debt servicing costs.

Severe weather events or other catastrophic natural disasters could also result in long-term reductions in demand for electricity or the slowing of customer growth in the Company's service territory, which could have a Material Adverse Effect.

High winds and lack of precipitation also increase the risk of wildfires resulting from the Company's infrastructure or for which the Company may otherwise have responsibility. If it is found to be responsible for such a fire, the Company could suffer material costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. If not recovered through these means or if recovery is delayed, they could result in a Material Adverse Effect. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

The Company purchases power from third-party owned hydroelectricity sources and operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities.

Climate Change Risk

Physical Risk:

Climate change may negatively impact the Company's operations as a result of increased frequency and intensity of weather events and related physical risks, any of which could result in a Material Adverse Effect (for more information refer to "Weather Risk" and "System Operating and Maintenance Risks"). An increase in physical risk associated with climate change can also adversely impact the cost and availability of insurance, insurance deductibles and self-retention, as well as credit ratings, which could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability (refer to "Liquidity and Capital Markets Risk").

Transition Risk:

As government policy and the economy transition toward decarbonization, the Company is exposed to risks arising from policy, legal, technology, and market changes, which could result in a Material Adverse Effect. The energy transition will require the Company to address changes to environmental policies, laws and regulations which are being proposed and adopted in many jurisdictions in response to

concerns regarding the effects or impacts of climate change (refer to “Environmental Legislation”). The pace of such new initiatives is expected to accelerate.

The Company will be required to manage the impacts of these changes on customer demand and rates, while integrating increased amounts of intermittent renewable energy sources and new technologies, implementing and making the investments required to meet new resiliency and security standards, and adapting the Company’s infrastructure and generating capacity to meet changing customer demands and usage patterns. The energy transition and the ability of the Company to achieve mandated climate related targets and goals will require significant capital investment, effective engagement with policymakers, regulators and stakeholders, and depend upon many factors which are outside of the Company’s direct control. Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets.

Given concerns regarding carbon-emitting generation, assets and businesses may, over time, become difficult or uneconomic to insure in commercial insurance markets. Some insurance companies have begun to limit their exposure to coal-fired electricity generation and are evaluating the medium and long-term impacts of climate change which may result in less insurance capacity, more restrictive coverage and increased premiums. The Company could also face litigation or regulatory action related to environmental harms from GHG emissions or failure to substantiate certain environmental claims.

The failure to effectively respond to climate change transition risks could adversely affect the Company’s ability to deliver safe, reliable, and cost-effective service, the Company’s reputation with stakeholders, its ability to operate and grow, and the Company’s access to, and cost of, capital, each of which could result in a Material Adverse Effect.

Cybersecurity Risk

NSPI is exposed to potential risks related to cyberattacks, data breaches, cyber-extortion, and unauthorized access that could result in a Material Adverse Effect. The Company relies on IT systems, cloud infrastructure, third-party service providers and the diligence of its team members to effectively manage and safely operate its assets. This includes controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other enterprise systems. As the Company operates critical energy infrastructure, it may be at greater risk of cyberattacks, which could include those from nation-state cyber threat actors. Major emerging and ongoing global conflicts may also elevate this risk, by increasing the sophistication, magnitude, and frequency of cyberattacks.

Cyberattacks can reach the Company’s assets and information via their interfaces with third parties or the public internet and gain access to critical and non-critical infrastructures. Cyberattacks can also occur via personnel with access to critical assets or trusted networks. Methods used to attack critical assets could include generic or energy-sector-specific malware delivered via network transfer, removable media, attachments, links in e-mails or other communications, or social engineering. The methods used by attackers are continuously evolving and can be difficult to predict and detect and may become more sophisticated, frequent, severe, and difficult to stop to the extent that attackers are able to leverage evolving artificial intelligence models or tools.

Despite security measures in place, the Company’s systems, assets and information could experience security breaches that could cause system failures, disrupt energy supply and delivery, business operations, or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers, unavailability of critical assets, safety issues, compromise billing and customer-facing information, such as outage maps, disrupt internal control and financial processes, or result in the release, loss, corruption, destruction, and/or misuse of critical, sensitive, confidential or proprietary information, intellectual property, or personal information of customers or employees. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Cyberattacks or unauthorized access may cause lost revenues, costs, losses, regulatory penalties and third-party damages all, or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. This could result in a Material Adverse Effect and there is no assurance that cyberattacks, or other security breaches can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards and policies derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework, periodic security testing, program maturity objectives, cybersecurity incident readiness program, and employee communication and training. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and IT including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation and Northeast Power Coordinating Council that have been approved by the UARB. The status of key elements of the Company's cybersecurity program is reported to the Board of Director on a quarterly basis.

Energy Consumption Risk

NSPI is affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, weather events, customers' focus on energy efficiency, changes in rates, and advancements in new technologies, such as rooftop solar, electric vehicles, data centers, and battery storage. Government policies promoting energy efficiency, distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact NSPI's operations, rate base, net earnings and cash flows and result in a Material Adverse Effect.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. NSPI may enter foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases and capital investment. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations. NSPI's regulatory framework permits the recovery of prudently incurred costs, including foreign exchange. The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

The risk due to fluctuation of the CAD against the USD for fuel purchases is measured and managed. In 2025, NSPI expects approximately 54 per cent of its anticipated net fuel costs to be denominated in USD. Forward contracts to buy \$208 million USD were in place as at December 31, 2024 at a weighted average rate of \$1.3361, representing 51 per cent of 2025 anticipated USD requirements. Forward contracts to buy \$69 million USD in 2026 at a weighted average rate of \$1.3296 were in place as at December 31, 2024. These contracts cover 18 per cent of anticipated USD requirements in 2025. As at December 31, 2024, there were no fuel-related foreign exchange swaps outstanding. NSPI reassesses foreign exchange forecasts periodically and will enter into additional hedges or unwind existing hedges, as required.

Liquidity and Capital Market Risk

Liquidity risk relates to NSPI's ability to ensure sufficient funds are available to meet its financial obligations. NSPI's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent NSPI from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. NSPI's operations require significant capital investments in PP&E and the risk associated with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access cost-effective capital could have a material impact on

NSPI to fund its operations. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions.

The Company is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business, its regulatory framework and legislative environment, political interference in the regulatory process, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes, wildfires, and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings or increased borrowing costs under certain existing credit facilities. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral.

General Economic Risk

The Company has exposure to the macro-economic conditions in Nova Scotia. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity, and in turn the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could have a Material Adverse Effect. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

Interest Rate Risk:

NSPI utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk.

The allowed range of ROE will generally follow the direction of interest rates, such that it is likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. The cost of debt is a component of rates and prudently incurred debt costs are recovered from customers.

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

As at December 31, 2024, 95 per cent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 17 years.

Inflation Risk:

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates.

Public Health Crisis Risk

An outbreak of infectious disease, a pandemic or other public health threats, or a fear of any of the foregoing, could result in a Material Adverse Effect to NSPI. This could include causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity, revenue, operating costs, timing and extent of capital investments, capital market activities, and counterparty risk; which could result in a Material Adverse Effect.

Health and Safety

The Company's operations inherently involve risk to the health and safety of employees, contractors and members of the public. Personal injury or loss of life could result from failure to implement or observe appropriate health and safety procedures or comply with health and safety laws and regulations could result in adverse operational, reputational, legal, regulatory, or financial impacts, any of which could have a Material Adverse Effect.

Project Development and Land Use Rights Risk

The Company's capital plan includes significant investment in generation, infrastructure modernization and customer-focused technologies. Any projects planned or currently in construction, particularly significant capital projects, may be subject to risks that could result in a Material Adverse Effect including, but not limited to, impact on costs from schedule delays, increased demand for renewable energy inputs, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial and municipal levels. There is no assurance that NSPI will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

Some of the Company's assets are located on land owned by third parties, including Indigenous Peoples, and may be subject to land claims. Present or future assets may be located on lands that have been used for traditional purposes and therefore subject to specific consultations, consents, or conditions for development or operation. If the Company's rights to locate and operate its assets on any such lands are subject to expiry or become invalid, it may incur material costs to renew rights or obtain such rights. If reasonable terms for land-use rights cannot be negotiated, the Company may incur significant costs to remove and relocate its assets and restore the land. Additional costs incurred could cause projects to be uneconomical to proceed with.

Counterparty Credit Risk

The Company is exposed to risk related to its reliance on certain key partners, suppliers, and customers any of which may endure financial challenges resulting from commodity price and market volatility, economic instability or adversity, adverse political or regulatory changes and other causes which may cause or contribute to such parties' insolvency, bankruptcy, restructuring or default on their contractual obligations to NSPI. The Company is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty's non-performance under an agreement.

There is no assurance that management strategies will be effective, and significant counterparty defaults could result in a Material Adverse Effect.

Commercial Relationships Risk

The Company is exposed to commercial relationships risk in respect of its reliance on certain key partners, suppliers and customers. For the year ended December 31, 2024, NSPI's five largest customers contributed approximately 9 per cent (2023 – 8 per cent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues and could have a Material Adverse Effect.

Supply Chain Risk

NSPI's ability to meet customer energy requirements, respond to storm-related disruptions and invest in capital in a cost-effective and timely manner are dependent on maintaining an efficient supply chain. Domestic and global supply chain issues may delay the delivery, increase the cost, or result in shortages

of certain materials, fuel, equipment and other resources that are critical to the Company's operations. These disruptions may be further exacerbated by inflationary pressures, labor shortages, more frequent and severe weather events, government incentives increasing demand for clean energy projects, changes in carbon-related costs, policies and regulations, and the impact of international conflicts. In addition, global supply chains and the financial condition and results of the business could be Materially Adversely Affected by the imposition of custom duties or other tariffs, or an increase in trade restrictions in the future. Failure to eliminate or manage supply chain constraints may impact the availability and cost of items and labour that are necessary to support operations and capital investment and could have a Material Adverse Effect.

Fuel Supply Disruptions:

NSPI is also exposed to the risk of fuel supply chain disruptions, both within and outside NSPI's service territory, which may be caused by severe weather or natural disasters. This may also be caused by damage to, operational issues with, terrorist or cyberattacks on, third party fuel production, storage, pipeline, and distribution facilities. Significant unanticipated fuel supply disruptions could result in increased exposure to commodity price risk for NSPI and could have a Material Adverse Effect.

Commodity Price Risk

The Company's fuel supply is subject to commodity price risk.

The Company's fuel supply is exposed to broader global market conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to, currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks, such as political instability, conflicts, changes to international trade agreements, tariffs, trade sanctions or embargos.

Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales, any of which could result in a Material Adverse Effect.

Subject to available liquidity in suitable hedging products, NSPI targets to be 75-100 per cent hedged for 2025 and 50-90 per cent hedged for 2026. NSPI reassesses fuel consumption forecasts quarterly and will enter into additional hedges or unwind existing hedges, as required, to rebalance the portfolio and ensure the objective of fuel cost stability is maintained while minimizing transaction costs.

Coal:

A substantial portion of NSPI's coal supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements for forecast quantities of coal with several suppliers, as part of the fuel procurement portfolio strategy. As at December 31, 2024, the approximate percentage of forecast coal requirements hedged is 100 per cent for 2025 and 11 per cent for 2026.

Petcoke:

As at December 31, 2024, the forecast petcoke requirements for 2025 are fully hedged.

Natural Gas:

NSPI periodically enters into physical and/or financial contracts based on forecast natural gas consumption to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2024, the approximate percentage of forecast natural gas requirements hedged for 2025 is 81 per cent and 2026 is 49 per cent.

Heavy Fuel Oil:

NSPI periodically enters into physical and/or financial contracts based on forecast heavy fuel oil purchases to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2024, forecast heavy fuel oil requirements are fully hedged for 2025.

Power Purchases:

NSPI has fixed price agreements relating to NLH's NS Block energy delivery obligations and power purchase agreements with IPPs. NSPI also periodically enters into additional physical and/or financial contracts based on forecast power purchases to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2024, the approximate percentage of forecast power purchase requirements hedged is 76 per cent for 2025 and 46 per cent hedged for 2026.

Future Employee Benefit Plan Performance and Funding Risk

NSPI has both defined benefit and defined contribution employee benefit plans that cover both employees and retirees. The defined benefit plan is closed to new entrants. The cost of providing the defined benefit plan varies depending on the plan provisions, interest rates, inflation, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. The three largest drivers of costs are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates, future inflation and actual versus expected investment performance, NSPI could be required to make larger contributions in the future to fund these plans, which could have a Material Adverse Effect.

Labour Risk

NSPI's ability to deliver service to its customers depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could have a Material Adverse Effect.

Approximately 42 per cent of the full-time and term employees within the NSPI labour force are represented by a union and subject to a collective labour agreement, which expires March 31, 2026. The inability to maintain or negotiate future agreements on acceptable terms could result in high labour costs and work disruptions, which could adversely affect service to customers and have a Material Adverse Effect. There have been no labour disruptions since 1975.

Information Technology Risk

NSPI relies on various information technology systems to manage operations, including increasing reliance on IT solutions operated by third parties, such as software as a service and third party cloud hosting. This subjects NSPI to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital investment, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems. NSPI's digital transformation strategy, including investment in infrastructure modernization and customer focused technologies, is driving increased investment in information technology solutions, resulting in increased project risks associated with the implementation of these solutions.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, and any such changes could have a Material Adverse Effect. The value of NSPI's existing deferred income tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws.

System Operating and Maintenance Risks

The safe and reliable operation of electric generation transmission and distribution systems is critical to NSPI's operations. There are a variety of hazards and operational risks inherent in operating electric utilities. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, supply chain issues impacting timely access to critical equipment, activities of third parties, terrorism, cyberattacks, human error, damage to facilities and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires, other natural disasters. Electric utility transmission and distribution operation interruption could negatively affect customer and public confidence, and public safety and have a Material Adverse Effect.

Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could have a Material Adverse Effect. The regulatory framework for NSPI permits the recovery of prudently incurred costs.

Uninsured Risk

NSPI maintains insurance to cover accidental loss suffered to its facilities, and to provide indemnity in the event of liability to third parties. A significant portion of NSPI's transmission and distribution assets are not insured, as is customary in the industry, as the cost of coverage is prohibitive. In addition, NSPI accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred will be covered by insurance.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits, or claims that fall within a significant self-insured retention could have a Material Adverse Effect, if regulatory recovery is not available.

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are monitored by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company, including the establishment of the Credit Risk Oversight Committee. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks. Management reports quarterly on non-financial risks to the Board of Directors.

The Company manages its exposure to normal operating and market risks relating to commodity prices, and foreign exchange, through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil, natural gas and purchased power options, forwards and swaps. Collectively these contracts are considered derivatives.

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract

generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Derivatives entered into by NSPI, that are documented as economic hedges or that do not qualify for NPNS exception, are subject to regulatory accounting treatment, as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power, inventory or PP&E, depending on the nature of the item being economically hedged. Management believes that any gains or losses resulting from settlement of these fuel related derivatives will be refunded to or collected from customers in future rates through the FAM.

Regulatory Items Recognized on the Consolidated Balance Sheets

The Company has the following categories on the Consolidated Balance Sheets related to derivatives receiving regulatory deferral:

As at millions of dollars	December 31 2024	December 31 2023
Derivative instrument assets (current and other assets)	\$ 44	\$ 11
Regulatory assets (current and other assets)	40	78
Derivative instrument liabilities (current and long-term liabilities)	(38)	(77)
Regulatory liabilities (current and long-term liabilities)	(44)	(12)
Net asset (liability)	\$ 2	\$ -

Regulatory Impact Recognized in Net Income

The Company recognized the following net (losses) gains in income related to derivatives receiving regulatory deferral:

For the millions of dollars	Year ended December 31
	2024 2023
Fuel for generation and purchased power (1)	\$ (36) \$ 70

(1) Realized gains on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in "Fuel for generation and purchased power" when the hedged item is consumed.

Various valuation techniques are used to determine the fair value of derivative instruments at the reporting date. These may include quoted market prices or internal models using observable or non-observable market information.

DISCLOSURE AND INTERNAL CONTROLS

In accordance with National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, the Chief Executive Officer and Chief Financial Officer of the Company will file a Venture Issuer Basic Certificate with respect to the Company's annual consolidated financial statements and annual management's discussion and analysis. This Venture Issuer Basic Certificate is not required to include representations relating to the establishment and maintenance of:

- (i) controls and other procedures designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation (“DC&P”); and
- (ii) a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP (“ICFR”).

The issuer's certifying officers are responsible for ensuring that processes are in place to provide them with sufficient knowledge to support the representations they are making in this certificate. Investors should be aware that limitations on the certifying officers' design and implementation on a cost effective basis of DC&P and ICFR may result in additional risks to the quality, reliability, transparency and timeliness of interim and annual filings and other reports provided under securities legislation.

CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policy that is applicable to, and adopted by the Company in 2024, is described as follows:

Improvements to Reportable Segment Disclosures

The Company adopted Accounting Standard Update (“ASU”) 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance was effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Adoption of the standard resulted in additional qualitative disclosures provided in note 23.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023
Operating revenues	\$ 479	\$ 399	\$ 423	\$ 554	\$ 439	\$ 388	\$ 340	\$ 504
Net income	\$ 71	\$ 14	\$ 18	\$ 57	\$ 40	\$ 10	\$ 23	\$ 68

Quarterly operating revenues and net income are affected by seasonality. The first quarter is the strongest period, reflecting colder weather and fewer daylight hours. Seasonality and other weather patterns, including the number and severity of storms, can affect demand for energy and the cost of service.

SUMMARY OF SELECTED ANNUAL CONSOLIDATED FINANCIAL INFORMATION

The following table sets forth selected annual consolidated financial information of the Company for the three years ended December 31:

millions of dollars		2024		2023		2022
Operating revenues	\$	1,855	\$	1,671	\$	1,675
Net income	\$	160	\$	141	\$	131
Total assets	\$	7,117	\$	7,221	\$	6,842
Total long-term debt	\$	3,217	\$	3,868	\$	3,530

NON-CONFIDENTIAL

1 **Request IR-3:**

2
3 **Please file the current version of NS Power’s “The Path to 2030”.**

4
5 Response IR-3:

6
7 Please refer to Attachment 1 for the Path to 2030 Update (2024), filed as Appendix H to NS
8 Power’s 2025 Annual Capital Expenditure Plan (M12012).

2025 ACE Plan Appendix H

The Path to 2030 - 2024 Update

**The Path to 2030 - 2024 Update
Non-Confidential**

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1.0 EXECUTIVE SUMMARY

The Nova Scotia Utility and Review Board (NSUARB, Board) provided the following direction to Nova Scotia Power Incorporated (NS Power, Company) in its 2023 Annual Capital Expenditure (ACE) Plan Order (M11017) of September 12, 2023: “File a detailed and specific plan outlining how the Company will achieve the 2030 obligations, what specific steps are required to meet these obligations, how the proposed steps will accomplish that goal, and when these steps will be taken.” NS Power provided *The Path to 2030* report to the NSUARB on December 22, 2023. By letter on January 2, 2024, the Board entered *The Path of 2030* as an exhibit in the 2024 ACE Plan proceeding, and included it on the NSUARB’s 2024 ACE Plan final issues list. In the NSUARB’s Decision regarding the 2024 ACE Plan, it provided further direction regarding *The Path to 2030* reporting, as follows: “The Board directs that NS Power file an update on The Path to 2030 in the ACE Plan on an annual basis until 2030.” This year’s *The Path to 2030* report is submitted to the NSUARB with the 2025 ACE Plan in compliance with the Board’s directive.

The Government of Nova Scotia’s 2030 Clean Power Plan, released in October 2023, provides a comprehensive path forward for the province, and in particular NS Power, in meeting its 2030 Decarbonization Goals of achieving 80 percent electricity sales from renewable resources and the phase-out of coal generation by 2030. The 2030 Clean Power Plan aligns with NS Power’s Evergreen IRP Action Plan & Roadmap Update (M11307) completed in partnership with stakeholders in 2023. The high degree of alignment between the 2030 Clean Power Plan and the updated IRP Action Plan and Roadmap is positive, indicating there is clarity on the actions required to achieve the goals. Collectively, the 2030 Clean Power Plan and NS Power’s IRP Action Plan and Roadmap outline various investments and actions required in meeting the 2030 Decarbonization Goals.

In 2024, following recommendations by the Clean Electricity Solutions Task Force, the Provincial government announced a plan to create a new Independent Electricity System Operator in Nova Scotia (NSIESO) and a stand-alone energy regulator, called the Nova Scotia Energy Board. The

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1 creation of these two new entities changes the electricity planning landscape in Nova Scotia
2 including several changes to the Project Accountability Matrix.

3
4 • As described in **Section 4.0** and **Section 5.2.1**, any future Battery Storage projects will be
5 scoped and procured by the NSIESO.

6
7 • As described in **Section 4.0** and **Section 5.4.1**, all Fast-Acting Generation projects will be
8 procured by the NSIESO, including responsibility for the first 300 MW of generation
9 capacity.

10
11 • As described in **Section 4.0** the NSIESO will be responsible for future renewable energy
12 procurements, if needed, following the completion of the Green Choice Program and
13 Community Solar procurements that are currently underway.

14
15 NS Power is committed to supporting the transition of accountabilities to the NSIESO in
16 collaboration with NRR.

17
18 The new resources identified in the 2030 Clean Power Plan were summarized in **Figure 1** below
19 in last year's *The Path to 2030* report. These resources were updated in NS Power's 10 Year
20 System Outlook (10YSO) report submitted to the NSUARB on June 27, 2024, and the updated
21 timelines have been added to **Figure 1** for this year's update. With respect to resources, sizing,
22 and timing, this update to *The Path to 2030* report is consistent with the 2024 10YSO report unless
23 otherwise noted.

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Figure 1 – 2030 Clean Power Plan Resources

	Nameplate Capacity (MW)	Initial Anticipated COD (Year)	Updated Anticipated COD (Year)
Wind & Solar Resources			
Rate Base Procurement	306	2025	2025-2026
Green Choice Program	416	2028	2028
Port Hawkesbury Paper Wind	168	2025	2026
Renewable to Retail Wind	149	2024	2026 ¹
Community Solar	50	2025-2029	2025-2029 ²
Commercial Net Metering	50	2024-2029	2024-2029
Energy Storage Resources			
NS Power BESS Project	150	2025-2026	2025-2026
NSIESO Procurement	50-250 ³	2026	2027 ⁴
Fast Acting Generation Resources			
Stage 1	300	2027	2027
Stage 2	300	2029-2030	2029-2030
Fuel Conversions at Existing Units			
Gas Conversion – Point Tupper 2	150	2028	2028
HFO Operation – Lingan 1/3/4	459	2029	2029
Total New Wind & Solar			
	1,139		
Total New Energy Storage			
	200 - 400 ³		
Total New Fast Acting Generation			
	600		
Total Fuel Conversions			
	609		
Load Management Initiatives			
	150	2025-2029	2025-2029
Total Coal Phase Out			
	1,229		

¹Expected COD for Renewable to Retail wind farm is now 2026. See **Section 6.1.4** for further details.

²2026 was listed as the first year for community solar generation additions in the 2024 10 Year System Outlook. This has been revised in this document to recognize the New Dawn project coming online in 2025. As detailed in **Section 6.1.5** the next projects under this program are not expected until 2026.

³Stated range is as per 2023 Clean Power Plan, actual size of additional battery capacity to be determined by NSIESO.

⁴Stated COD is as per 10 Year System Outlook, actual timing of battery capacity additions will be determined by the NSIESO

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1 These resource additions form a comprehensive strategy that allows for flexibility to accommodate
2 future uncertainties. Through the ongoing Evergreen IRP Action Plan & Roadmap items, NS
3 Power is closely monitoring factors which may influence the Path to 2030, including load
4 management initiatives, electrification, and green hydrogen development. Achieving this
5 significant transition will require the coordination and cooperation of a broad group of partners
6 and stakeholders, including the Government of Nova Scotia, Independent Power Producers (IPPs),
7 EfficiencyOne (E1), Mi'kmaw Partners, NS Power, and the NSIESO, when established. These
8 parties will have various accountabilities in the development and execution of projects that will
9 add and integrate both renewable and dispatchable resources to the grid.

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2.0 INTRODUCTION

In its 2023 Annual Capital Expenditure (ACE) Plan Order (M11017) on September 12, 2023, the Nova Scotia Utility and Review Board (NSUARB, Board) directed Nova Scotia Power Inc. (NS Power, Company) to:

1) File a detailed and specific plan outlining how the Company will achieve the 2030 obligations, what specific steps are required to meet these obligations, how the proposed steps will accomplish that goal, and when these steps will be taken.

2) Use its best efforts to file such a plan with the 2024 ACE Plan. Keeping in mind the usual November filing of the ACE Plan. If this is not possible, the Board directs that a detailed plan be filed by December 31, 2023.

In its 2024 ACE Plan Order (M11458) on August 13, 2024, the NSUARB provided the following direction:

5. The Board directs that NS Power file an update on The Path to 2030 in the ACE Plan on an annual basis until 2030.

In compliance with the Board's direction, NS Power provides herein its 2024 *The Path to 2030* report, which describes the Company's plan to achieve its 2030 obligations. This document includes information regarding the following:

- The 2030 Decarbonization Goals
- The Province of Nova Scotia's 2030 Clean Power Plan
- Creation of the Nova Scotia Independent Energy System Operator (NSIESO)
- Resource Development Plan elements necessary to achieve the 2030 Clean Power Plan
- NS Power Integrated Resource Plan (IRP) Action Plan and Roadmap Items supporting the 2030 Decarbonization Goals
- Project Accountabilities, Coordination, and Risk Management considerations

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- 1 Details related to these topics will provide greater specificity with respect to how the Company
- 2 will meet its 2030 obligations, including more specific timelines for each element of its plan to
- 3 do so.

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3.0 2030 DECARBONIZATION GOALS

NS Power's 2030 decarbonization goals are mandated under several legislative and regulatory frameworks. Although there are many environmental regulations that apply to NS Power's planning and operating environment, the key items relating to planning for and achieving the 2030 obligations are described below. In this year's report there is no change to the details in **Section 3.1** 80 Percent Renewable Electricity Sales and **Section 3.2** Coal Phase Out.

3.1 80 Percent Renewable Electricity Sales

The Province of Nova Scotia amended the Renewable Electricity Regulations¹ on July 9, 2021. The amendment added a Renewable Electricity Standard for 2030 which provides that:

- Beginning in calendar year 2030, load-serving entities must supply customers with 80 percent renewable electricity.
- NS Power must acquire at least an additional 1,100 GWh from independent power producers to meet this new requirement.
- NS Power may incorporate contributions from renewable low-impact electricity acquired from a source outside Nova Scotia.

This requirement was incorporated into the most recent Evergreen IRP and is considered in the 2030 Clean Power Plan.

¹ N.S. Reg. 110/2021.

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3.2 Coal Phase Out

The Province of Nova Scotia introduced the *Environmental Goals and Climate Change Reduction Act*² on October 27, 2021, and the legislation received Royal Assent on November 5, 2021. This Act includes the following elements that influence NS Power's system planning requirements:

- To have 80 percent of electricity sales in the Province supplied by renewable energy by 2030.
- To phase out coal-fired electricity generation in the Province by the year 2030.

In addition to the provincial goal to phase out coal-fired electricity generation by 2030, the federal Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations³ prescribe various regulations on coal generating units, including a requirement to stop generating with coal by the year 2030. The requirement to phase out coal by 2030 was incorporated into the most recent Evergreen IRP and is considered in the Province of Nova Scotia's 2030 Clean Power Plan, described below.

3.3 Proposed Clean Electricity Regulations

In addition to the policies described above, NS Power is considering the proposed Clean Electricity Regulations (CER)⁴ as part of its long-term planning. These regulations, commencing in 2035, will regulate the electricity sector in Canada toward achieving net-zero emissions by 2050. Multiple drafts of these regulations have been released by Environment and Climate Change Canada and NS Power has been engaged with Environment and Climate Change Canada (ECCC) through their stakeholder engagement process. As part of this engagement, the Federal

² S.N.S. 2021, c. 20.

³ [Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations \(justice.gc.ca\)](https://www.justice.gc.ca/sor/2012-167) (SOR/2012-167).

⁴ Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.

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1 Government announced on September 16, 2024 that a common understanding was achieved with
2 the Government of Nova Scotia on the CER: the future CER will provide flexibilities to enable
3 system growth and support decarbonization in the Province while ensuring reliability for
4 customers.⁵ NS Power incorporated an earlier (pre-Canada Gazette 1) draft of the CER into its
5 2022-2023 Evergreen IRP modeling and accordingly this draft was considered in the IRP Findings
6 and Action Plan. NS Power will continue to monitor developments of the CER through to the end
7 of 2024 and the final release of the CER in Canada Gazette 2. ECCC has and continues to
8 acknowledge the requirement for emitting resources operating in a peaking capacity as part of the
9 CER, which is in alignment with NS Power's long-term strategy.

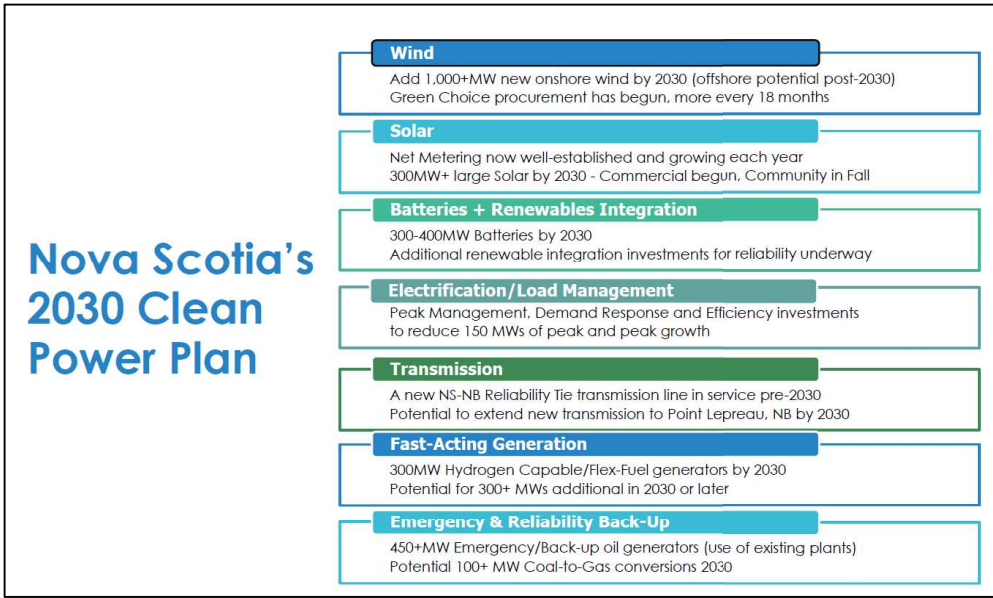
⁵ <https://www.canada.ca/en/natural-resources-canada/news/2024/09/ensuring-access-to-affordable-reliable-secure-and-non-emitting-electricity-in-nova-scotia.html>

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4.0 NOVA SCOTIA’S 2030 CLEAN POWER PLAN

On October 11, 2023, the Province of Nova Scotia released the 2030 Clean Power Plan.⁶ This release detailed the new resources that have been identified by the provincial government as being required to meet the 2030 decarbonization goals. A summary of the 2030 Clean Power Plan is shown in Figure 2 below.

Figure 2 – Nova Scotia’s 2030 Clean Power Plan (October 2023)



⁶ [nova-scotia-clean-power-plan-presentation-en.pdf](https://novascotia-clean-power-plan-presentation-en.pdf) (novascotia.ca)

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5.0 NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR

In February 2024, the Clean Electricity Solutions Task Force, a task force commissioned by the Nova Scotia provincial government, submitted its final report titled, “Modernizing Energy from Transition to Transformation.”⁷ This report identified several recommendations for the electricity sector including the creation of an independent energy system operator and stand-alone energy regulator. On April 5, 2024, The Energy Reform Act - Bill 404 received Royal Assent in Nova Scotia, which in turn enacted the *More Access to Energy Act* (MAEA). The MAEA, amongst other things, mandates the creation of the Nova Scotia Independent Energy System Operator (NSIESO). At this time, it is broadly understood the NSIESO will be responsible for resource and transmission system planning and energy resource procurement.

Since the announcement that an independent system operator will be established, the Department of Natural Resource and Renewables has confirmed to NS Power the NSIESO will be responsible for several components of the Clean Power Plan:

- Any future Battery Storage procurements will be scoped and procured by the NSIESO.
- All Fast-Acting Generation projects will be procured by the NSIESO, including responsibility for the first 300 MW of generation capacity.

In addition, the NSIESO will be responsible for future renewable energy procurements, if needed, following the completion of the Green Choice Program and Community Solar procurements that are currently underway.

The accountability Matrix in **Section 8.1** has been updated to reflect these changes. Accordingly, NS Power anticipates that the NSIESO, once established, will play a significant role in planning and execution of various elements of the Path to 2030 as described in this Plan. NS Power is

⁷ <https://cetaskforce.ca/wp-content/uploads/2024/02/Report-February-23-2024-Final-Signed.pdf>

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- 1 committed to supporting the transition of accountabilities to the NSIESO in collaboration with
- 2 NRR.

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6.0 RESOURCE DEVELOPMENT PLAN ELEMENTS

6.1 Wind and Solar Resources

The 2030 Clean Power Plan incorporates a significant quantity of new variable renewable generation which must be added to the grid by 2030. The required renewable energy projects will be procured by the Province of Nova Scotia, and in the future by the NSIESO, via multiple streams, with NS Power supporting each of these as required. Updates on each procurement stream are provided below, including next steps and timing for each project stream.

6.1.1 Rate Base Procurement

The Rate Base Procurement (RBP) program was initiated by the Province of Nova Scotia in 2021. The goal of the RBP was to contract for 1100 GWh of low-impact renewable electricity per section 6B(2)(b) of the Renewable Electricity Regulations⁸ as part of meeting NS Power's 2030 Decarbonization Goals.

The RBP involved a comprehensive renewable procurement managed by the Province of Nova Scotia's Procurement Administrator, Coho Climate Advisors (Coho). NS Power supported the procurement process by:

- Completing over 35 Feasibility (FEAS) Studies under the Generator Interconnection Procedures (GIP) in support of proponent bids.
- Providing feedback and participating in the NSUARB regulatory process to approve the RBP Power Purchase Agreement (PPA).
- Providing feedback on the draft Request for Proposals (RFP).

⁸ N.S. Reg. 155/2010 as amended to N.S. Reg. 338/2022.

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The RBP Portfolio was announced on August 17, 2022 and subsequently updated on July 12, 2023 and February 8, 2024. The RBP Portfolio initially included five (5) projects representing a total of 373 MW and 1,478 GWh of new wind generation to the Nova Scotia system. Since that initial portfolio was announced, one of the projects awarded a PPA withdrew from the program and a potential replacement project will not proceed under the RBP program. The RBP Program now includes four (4) projects totaling 306MW and 1,165 GWh of wind generation. The advancing projects are:⁹

- IR 673 - Benjamins Mill Wind near Falmouth in Hants County, developed by Natural Forces Development and Wskijnu'k Mtmo'taquinow Agency Ltd, an organization which represents the 13 Mi'kmaw Nations in the province.
- IR 669 - Higgins Mountain Wind Farm near Wentworth in Colchester and Cumberland counties, developed by Elemental Energy and Sipekne'katik First Nation.
- IR 668 - WEB Weavers Mountain Wind near Marshy Hope in Pictou and Antigonish counties, developed by SWEB Development and Glooscap First Nation.
- IR 677 - Wedgeport Wind Farm in Yarmouth County, developed by Elemental Energy and Sipekne'katik First Nation.

Through 2024, NS Power has been supporting the RBP Portfolio projects in moving through the GIP. GIP status for the RBP projects is summarized in **Figure 3** below.

⁹ <https://novascotiarp.com/updates>

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Figure 3 – RBP Project GIP Status

	SIS PART 1	SIS PART 2	FACILITY STUDY	GIA	COD
IR 673 Benjamins Mill	Complete	Complete	Complete	Executed	Oct 15, 2025
IR 669 Higgins Mountain	Complete	Complete	Complete	Executed	Jan 26, 2026
IR 668 Weavers Mountain	Complete	Complete	Complete	Executed	Dec 31, 2026
IR 677 Wedgeport	Complete	Complete	Complete	In Progress	TBD

NS Power is planning for the development of associated Network Upgrades and Transmission Provider Interconnection Facilities for these projects.

6.1.2 Green Choice Program

The Green Choice Program (GCP) was established in April 2022 following amendments to the *Electricity Act*.¹⁰ The goal of the GCP is to procure a minimum of 1500 GWh, and up to 2000 GWh, of new low-impact renewable electricity for which large-scale energy customers can contract to achieve their greenhouse gas emissions reduction targets while supporting the Province's 2030 decarbonization goals, per section 6B(3)(a) of the Renewable Electricity Regulations and per section 24 of the Green Choice Program Regulations.

As a voluntary corporate renewables program, GCP enables large energy consumers (with $\geq 10,000$ MWh of annual load) or aggregated partnerships (with $\geq 1,000$ MWh of annual load, individually, and with an annual minimum subscribed energy of 10,000 MWh) to subscribe up to 120 percent of their annual load to the renewable energy generation projects selected through the RFP process. The Green Choice Program procurement will solicit sufficient new renewable electricity to serve the subscribed load on an annual basis. NS Power will be responsible to continue to plan and operate the system such that it has sufficient capacity available to supply the subscribed load.

¹⁰ S.N.S. 2022, c. 12.

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The GCP involves a renewable electricity procurement managed by the Province of Nova Scotia's Procurement Administrator, Coho, and a tandem participant intake process managed by the provincial department of Natural Resources and Renewables (NRR), Coho, and with support from NS Power. To date, NS Power has supported the program development by:

- Providing feedback and input on the Participant Guide.
- Development of frequently asked questions (FAQs) for participants, specific to Renewable Energy Credits (RECs), published on the GCP website.
- Providing feedback on the draft Request for Proposals (RFP) and the Power Purchase Agreement (PPA), including participation in the public feedback process.
- Providing feedback on materials and attending and being available for questions during both participant and proponent webinars.
- Development of near-term forecast carbon cost on a variable (dollar-per-MWh) basis for publishing on the GCP website.
- Providing feedback, as requested, on participant resources, educational and support materials, and participant agreement/terms and conditions.
- Providing feedback on the draft participant application form and guide.
- Providing feedback on the draft Participant Agreement.
- Completing twenty-one feasibility studies as part of the Generation Interconnection Process for prospective GCP candidates

On December 1, 2023, Coho issued the RFP associated with the GCP. Final bids closed in June 2024. In August 2024, proponents electing to opt-in to Canda Infrastructure Bank (CIB) financing were asked to re-submit pricing, with CIB financing assumed, by October 11, 2024. NS Power understands that proponents selected to be part of the GCP portfolio will be announced after government transition, following the provincial election held on November 26, 2024, is complete. Consistent with requirements under the *Electricity Act*, NS Power shall procure all electricity under a contract awarded by a procurement administrator. Projects selected as part of the GCP portfolio are expected to commit to a commercial operation date (COD) on or before December 31, 2028.

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While the Green Choice Program procurement is open to various types of renewable generation, it is anticipated that the majority of the projects selected will be wind energy projects.

NS Power will continue support of the Green Choice Program development by:

- Continuing to collaborate with NRR and Coho regarding details of the program administration and customer support processes.
- Verification of applicant consumption data and account status.

Like the RBP projects, once the procurement is complete and PPAs are awarded, NS Power will support the development of these projects via the completion of System Impact Studies (SIS) and Facilities Studies, and development of Transmission Provider Interconnection Facilities and Network Upgrades associated with each project. In response to the latest GCP award timeline, and to ensure that projects awarded a PPA are able to enter the SIS process quickly following selection, NS Power has added an additional study group to the SIS Study Calendar in early 2025 to match the anticipated ability of projects to reach the appropriate GIP milestones.

6.1.3 Port Hawkesbury Paper Wind (IR 618 and IR 742)

Port Hawkesbury Paper Wind (PHP Wind), a sister company to Port Hawkesbury Paper, is pursuing the development of a proposed 168 MW wind farm to support the long-term sustainable operation of the paper mill. The environmental assessment for this project was approved by the provincial government in March 2023, and groundbreaking for this project occurred in September 2024.¹¹ PHP Wind forecasts commercial operation to start in the fourth quarter of 2026.

NS Power has been supporting the PHP Wind project as it moves through the GIP. There are currently two IRs associated with the project. Goose Harbour Lake I (IR 618) and Goose Harbour Lake II (IR 742). GIP status for the PHP Wind project is summarized in **Figure 4** below:

¹¹ <https://www.cbc.ca/news/canada/nova-scotia/port-hawkesbury-paper-building-guysborough-county-wind-farm-1.7327216>

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Figure 4 – PHP Wind Project GIP Status

	SIS Part 1	SIS Part 2	Facilities Study	GIA Executed
IR 618 Goose Harbour Lake I	Complete	Complete	Complete	Executed
IR 742 Goose Harbour Lake II	In Progress	In Progress	Pending	Pending

6.1.4 Renewable to Retail

The Renewable to Retail (RtR) electricity market was established in Nova Scotia in 2016 to enable independent licensed retailers to sell renewable energy generated within the Province directly to NS Power's retail customers. One Licensed Retail Supplier (LRS) licence has been granted to provide service under the RtR tariffs.

In the Company's 2022 Load Forecast Report, which was the load forecast used in the development of the Evergreen IRP, 29 GWh of energy sales was forecast to be supplied under the RtR tariff. In the 2023 and 2024 Load Forecast Reports the volume of sales supplied through the RtR tariff increased to 130 GWh and 250 GWh, respectively. NS Power's Load Forecast Report provides details of how these forecasts have been developed and these will continue to be updated as part of NS Power's load forecasting process. While not explicitly considered in the Evergreen IRP, this increase in expected wind generation is consistent with the 2030 Clean Power Plan. The customer load represented by RtR is in-province load and wind generation built to meet this load is aligned with the need for new wind generation to meet the 2030 Decarbonization Goals.

The Path to 2030 and NS Power's 2024 10 Year System Outlook contain 148.5MW of new wind generation proposed to supply RtR customers (IRs 597 and 675), and the first commercial operation is now anticipated in 2026. On November 1, 2024 the LRS submitted a request to the Board to extend the license holder deadline to sell renewable low-impact electricity to customers

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to December 31, 2026. On November 12, 2024 the Board issued an Order approving the request to extend the deadline (M10293).

In addition to these two interconnection requests, two additional requests, IR 739 (90 MW) and IR 785 (223 MW), associated with RtR program have active transmission interconnection requests and NS Power is supporting their progress through the GIP. The GIP status for RtR projects is summarized in **Figure 5** below.

Figure 5 - GIP Status for RtR Projects

	SIS PART 1	SIS PART 2	FACILITY STUDY	GIA	10 11
IR 597 Mersey Wind 1	Complete	n/a*	Complete	Executed	12
IR 675 Mersey Wind 2	Complete	Complete	Complete	In Progress	13
IR 739 Greenfield Wind	In Progress	In Progress	Pending	Pending	14
IR 785 West Wind Farm	Feasibility Study Complete				15

*IR 597 was completed in SIS Group 30, prior to the requirement for EMT analysis that is completed during SIS Part 2. The requirement for a SIS Part 2 study is applicable to SIS Groups 32 – 34, where NS Power worked to provide the load flow and dynamic analysis under SIS Part 1 in advance of the EMT analysis in Part 2 to assist interconnection customers with project development. Starting in SIS Group 35, the reports will be combined into a single SIS Report containing load flow, dynamic, and EMT analysis.

6.1.5 Community Solar Program

The Community Solar Program launched in Q1 2024, following proclamation of amendments to the *Electricity Act*¹² and the registration of the Community Solar Regulations. The program was first conceived in April 2022, when the Government of Nova Scotia passed amendments to the *Electricity Act* (in SNS 2022, c 12, s 5) that enable a Community Solar Program, administered by NS Power, pending the Order in Council that came earlier this year. The Province's stated goal¹³

¹² S.N.S. 2022, c. 12, s 5.

¹³ Action 18 contained within "Our Climate, Our Future – Nova Scotia's Climate Change Plan for Clean Growth" available at <https://climatechange.novascotia.ca/sites/default/files/uploads/ns-climate-change-plan.pdf>

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for the Community Solar Program is to enable at least 50 MW of new community solar generation and facilitate equitable access to renewable energy, including for those otherwise unable to install on-site renewables through either Commercial Net Metering or the self-generating option.

The program will encourage the development of new community solar gardens with a project nameplate capacity of between 0.5 MWac and 10 MWac. Each community solar garden project is built, owned, and operated by an eligible project owner which may include municipalities, towns, First Nations, not-for-profits, towns/townships and villages, business, co-operative, colleges and universities, or a partnership within the aforementioned. The program capacity for all community solar gardens combined is 100 MW.¹⁴

In order to enable the Community Solar program two regulatory proceedings are before the Board. The provincial department of NRR filed the Community Solar PPA (M11903) with the NSUARB on September 25, 2024 and NS Power filed the Community Solar Energy Credit Rider (M11911) with the NSUARB on October 1, 2024. These proceedings are expected to conclude in Q1 2025 and will enable solar gardens to enter into PPA's with NS Power and customers to subscribe to the program.

The first project, a 0.585 MW community solar garden located at Pine Tree Park Estates in Sydney, Cape Breton has 29 residential and commercial subscribers and is anticipated to be enrolled in the program following the conclusion of the regulatory process. NS Power anticipates the next projects will come online no sooner than Q1 2026 and the majority will be connected to the distribution system.

The Community Solar Program is a rolling application intake managed by the provincial department of NRR. Once a project is approved by the Minister, the Project is awarded a PPA and can enter into a Distribution System Impact Study (DSIS) study window for the Distribution Generation Interconnection Procedure (DGIP).

¹⁴ Nova Scotia Department of Natural Resources and Renewables, "Nova Scotia Community Solar Program Guide." February 2024. Accessed at: <https://energy.novascotia.ca/sites/default/files/community-solar-program-guide.pdf>

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NS Power will administer the program billing and assist project owners in subscriber management.

To date, NS Power has supported the program development by:

- Providing feedback and input on the Community Solar Program Guide and Program Application.
- Providing feedback and input on the PPA.
- Development and submission of the Community Solar Energy Credit Rider.
- Providing feedback on materials and attending and being available for questions during webinars.
- Providing feedback, as requested on participant resources, educational and support materials for both programming and interconnection.
- Development of program administration and processes within NS Power.
- Filing the Community Solar Energy Credit Rider (M11911) with the NSUARB on October 1, 2024, along with a letter of support from NRR.
- Completing preliminary assessments for distribution generation interconnect requests.

As of November 25, 2024, NS Power has completed 40 preliminary assessments in 2024 for potential projects under the Community Solar program. Eight additional preliminary assessment are in progress. The 48 projects represent a total potential of 335 MW of installed capacity. Like the other renewable projects, once an application is accepted by the Minister and a PPA is awarded, NS Power will support the development of these projects via the completion of System Impact Studies and Facilities Studies, and as required, the development of Interconnection Facilities and Network Upgrades associated with each project.

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6.1.6 Commercial Net Metering

April 2022 amendments to the *Electricity Act (Nova Scotia)* established the framework for a new net metering program. October 2022 amendments to the *Renewable Energy Regulations*.¹⁵ required that NS Power develop and apply to the NSUARB for approval of the new program by November 2022. NS Power received Board approval for the new Commercial Net Metering Program (CNMP) in July 2023. In August 2023, CNMP was made available for Class 1 Service (installations greater than 27 kW up to 100 kW) and, in October 2023, for Class 2 Service (installations greater than 100 kW up to 1 MW).

CNMP enables customers to generate renewable electricity from a variety of eligible sources (e.g. solar, wind, hydro) for their own use and to export excess electricity to NS Power. Energy exported to NS Power is banked and applied to the customer's next bill to offset energy drawn from the grid until the end of the calendar year. Customers participating in CNMP remain on their existing tariff and exported/banked energy is applied at a rate equivalent to the rate paid for electricity up to a maximum of the customer's total billed electricity within the same calendar year. In comparison to the legacy Net Metering program (under NS Power's Regulation 3.6), CNMP provides an expanded nameplate capacity limit (up to 1 MWac).

NS Power filed the first annual CNMP Report on March 31, 2024, which included the following highlights, as of December 31, 2023:

- 371.9 kW of solar PV installed with an estimated annual output of 400.7 MWh.
- 1,763.9 kW of additional solar PV pending installation with an expected annual output of 1,936.1 MWh.
- 93 percent of requests were for Class 1 Commercial Net Metering Service (Generators up to 100 kW).

¹⁵ N.S. Reg. 338/2022.

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- 1 • 7 percent of requests were for Class 2 Commercial Net Metering Service (Generators
2 greater than 100 kW up to 1 MW).
- 3 • 3 percent of requests were for generators having a nameplate capacity greater than 200 kW
4 (Nameplate capacity group 2).
- 5

6 As of November 25, 2024, NS Power has completed 21 preliminary assessments in 2024 for
7 potential projects under the CNMP. Two additional project preliminary assessment are in progress.
8 The 23 projects represent a total potential installed capacity of 8.9 MW.

9

10 **6.1.7 Additional Renewable Energy Procurements**

11

12 The projects and programs identified above total approximately 1000 MW of new wind generation
13 and over 100 MW of new solar generation (depending on program uptake) beyond what is already
14 in service on the Nova Scotia grid, all of which are anticipated to be in service by 2030. This
15 represents a significant portion of the total resources identified in the 2030 Clean Power Plan as
16 being required to meet 2030 Decarbonization Goals.

17

18 The Nova Scotia 2030 Clean Power Plan identifies the potential for additional procurement
19 activities beyond those noted here to develop the remaining resource requirement; these activities
20 are anticipated to begin in the 2025-2027 timeframe in order to provide sufficient time to reach
21 commercial operation by 2030. The NSIESO will be responsible for new renewable procurements
22 and procurement target(s) for these remaining solicitation(s) will be set by the NSIESO. NS Power
23 understands that NRR and their procurement administrator, Coho, will conclude the currently
24 active procurements for the Green Choice and Community Solar programs.

25

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6.2 Battery Storage & Renewable Integration Resources

The 2030 Clean Power Plan calls for deployments of grid-scale storage in Nova Scotia. In 2024 150 MW of 4-hour storage capacity was approved by the NSUARB and additional storage capacity is anticipated to be added via future procurement activities.

6.2.1 NS Power Battery Storage Project (ECEI)

NS Power filed an application with the NSUARB for the Battery Energy Storage System Project on January 25, 2024 for three 50 MW, four-hour battery sites located near the following existing NS Power substations:

- 99W Bridgewater
- 132H Spider Lake
- 43V Canaan Rd (White Rock Road)

The NSUARB approved the Company's capital cost application on June 13, 2024 and the BESS project proceeded through the Decision Gate 3 governance milestone in late June, resulting in the execution of the BESS Engineering, Procurement and Construction contract with e-Storage (a subsidiary of Canadian Solar Inc.) on July 2, 2024.

Construction activities have begun on all three BESS sites. At Bridgewater, a new driveway was constructed, civil works were completed in preparation for the installation of primary interconnection equipment, and subsequently primary equipment was installed. The main power transformer for the site was delivered and placed in the substation in late September 2024. Driveway extension construction at the Spider Lake BESS site has been completed in advance of the delivery and installation of the site's main power transformer which was completed in November. The commissioning dates for the Bridgewater and Spider Lake BESS sites are Q4 2025.

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Early site preparation activity for the White Rock Road BESS site has also been completed with the construction of the access driveway in December. The commissioning date for the third BESS site is Q3 2026.

Figure 6 – Main transformer installation for Spider Lake BESS site.



As directed by the Board in its Order regarding M11539, NS Power will provide a detailed interim update report to the NSUARB and stakeholders by September 30, 2025, summarizing actual project costs incurred and external funding developments relative to initial cost estimates included in the Company's capital cost application, and additional updates on the projected completion dates for the three BESS Project sites.

6.2.2 Battery Storage Procurement

On March 22, 2023, the Province introduced amendments to the *Electricity Act*¹⁶ that provide new procurement pathways for energy storage in Nova Scotia. Specifically, the changes to the Act

¹⁶ S.N.S. 2023, c. 17.

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1 allow NRR to issue RFPs for energy storage solutions and contracts for well-developed, innovative
2 energy storage projects that can be implemented quickly.¹⁷

3
4 The amendments provide two pathways for new energy storage projects to be designated by the
5 Province:

- 6
7 • Energy Storage Procurements may be initiated under Section 4B of the Act.
8 • Energy Storage Projects may be prescribed under Section 4D (2) of the Act.
9

10 In last year's The Path to 2030 update, NS Power anticipated that up 150 MW of energy storage
11 capacity may be designated, in the near term, by the Province under Section 4D and an additional
12 100 MW of energy storage capacity would be procured by the Province under Section 4B. Since
13 that update the Province has confirmed to NS Power that all future energy storage capacity
14 additions will be procured through a competitive process to be led by the NSIESO. The quantity
15 of energy storage capacity added via procurement and the timing of new energy storage additions
16 is expected to be determined by the NSIESO.

17
18 **6.2.3 Grid Stability & Renewable Integration Resources**

19
20 The transition from a traditional power system, largely made up of synchronous generators, to a
21 power system which will rely heavily on inverter-based resources (IBRs) such as wind, solar, and
22 battery energy storage, will require new sources of grid support to maintain the stability, reliability,
23 and power quality of the transmission system.

24
25 On December 8, 2023, NS Power released its report *Large Scale Integration of Inverter Based*
26 *Resources in Nova Scotia*¹⁸ (Integration Report) as part of its IRP Action Plan. The report
27 identified key metrics for Frequency Control and System Strength which are incorporated into
28 system studies where grid stability issues are identified, mitigation options are assessed, and

¹⁷ [Electricity Act Amendments Allow More Energy Storage Solutions - Government of Nova Scotia, Canada](#)

¹⁸ [Wind-Integration-Study-Large-Scale-Integration-of-IBR-in-Nova-Scotia-Public.pdf \(nspower.ca\)](#)

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1 mitigations are incorporated into grid design and specifications. Mitigation options identified in
2 the report and under assessment include:

- 3
- 4 • IBR Control System Design
 - 5 • Battery Energy Storage Systems
 - 6 • Synchronous Condensers
 - 7 • Flexible AC Transmission System (FACTS) Devices, Static Var Compensators (SVCs),
8 Static Synchronous Compensators (STATCOMs), Switched and Static Capacitor Banks
 - 9 • Fast-Acting Synchronous Generation
 - 10 • Transmission Connections
 - 11 • Operating Guidelines
- 12

13 Mitigation options, such as those identified in the bullets above, will be needed to support both
14 existing and new inverter-based resources to allow for maximum integration of IBR in Nova Scotia
15 while maintaining grid stability and reliability. Updates on BESS (see **Section 6.2.1**), Reliability
16 Tie (see **Section 6.3**), and Fast Acting Generation (see **Section 6.4**) are provided separately in this
17 report.

18

19 NS Power is also advancing a synchronous condenser project in alignment with The Path to 2030.
20 On January 16, 2024 the Minister of NRR issued a directive to NS Power to provide equipment
21 and systems necessary to supply the inertia response required to maintain the stability, reliability,
22 and power quality of the transmission system for interconnection by wind energy conversion
23 systems (WECS) procured pursuant to Sections 4B (1) (a), (b), and (e) of the Electricity Act. At
24 this time, four Interconnection Customers fall under this directive (please refer to **Figure 3**). NS
25 Power has prioritized, for first installation, the inertial support for Benjamin's Mill and Wedgeport
26 based on the studied grid conditions near those wind farms. NS Power has:

27

- 28 • Prioritized the four sites based on local grid conditions.
 - 29 • Identified locations at existing NS Power substations near the first two sites.
-

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-
- 1 • Developed a procurement approach for the synchronous condenser equipment.
 - 2 • Initiated substation design activities to accommodate the synchronous condensers.

3

4 This project has been included in the 2025 ACE Plan as a project for subsequent submission

5 (C0065943 – ECEI Synchronous Condenser). In addition to synchronous condensers supporting

6 wind farms, centralized synchronous condensers are anticipated to be required as large thermal

7 units are retired or not required online as wind generation online increases. System studies are

8 ongoing to determine the optimal sizing and location.

10 **6.3 Reliability Tie**

11

12 The Reliability Tie is a second 345 kV AC transmission line between Onslow, NS and Salisbury,

13 NB. It will improve the reliability of Nova Scotia's transmission link to the New Brunswick Power

14 (NB Power) system and the broader Eastern Interconnection, enabling the integration of additional

15 variable renewable generation on the Nova Scotia system. The Reliability Tie is not anticipated

16 to provide incremental access to firm capacity or energy. NS Power is developing the Reliability

17 Tie in collaboration with NB Power with a target in-service date in 2028, in alignment with the

18 2030 Clean Power Plan.

20 **6.3.1 Update on Reliability Tie Project (ECEI)**

21

22 The Reliability Tie Project continues to progress toward its target in-service date. The Company

23 has provided recent project progress updates in the 2024 IRP Action Plan Update and the 2024 10-

24 Year System Outlook proceeding. Below is a summary of the progress made on the Reliability Tie

25 Project in 2024:

- 27 • Significant progress has been made on the Intertie Project's Development Agreement with
- 28 NB Power. Coordination activities with the NB Power team on advancing pan-project
- 29 matters (e.g. quality management, project controls and integrated schedule refinement)

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1 have ramped up in 2024. A focused effort on setting up project processes and procedures
2 for both teams will continue into the first two quarters of 2025.

- 3
- 4 • Environmental Assessment (EA) Filing: NS Power received approval for the EA of the
5 Nova Scotia portion of the Reliability Tie Project in December 2023. Follow-up studies to
6 support the EA conditions are progressing on schedule. The Company's Environmental
7 Protection Plan for the Project is on track to be submitted to NS Environment and Climate
8 Change in late Q4 2024 or early Q1 2025.

- 9
- 10 • Mi'kmaq Engagement: NS Power and the KMKNO signed a Collaboration Agreement on
11 the building of the intertie in Q4 2023. Regular engagement continues with the Benefits
12 Coordinator and the Implementation Committee for the Agreement to highlight
13 opportunities for First Nations employment and businesses to participate in the project. The
14 KMKNO have completed a review of the Project Environmental Protection Plan and
15 provided their feedback October 17, 2024. NS Power is working to address their feedback.

- 16
- 17 • Engineering and Procurement: Detailed design is complete or near completion for all
18 segments of the project. All major RFPs for the materials and construction services
19 required to execute the project have been released to market as of October 22, 2024.
20 Proposal evaluations are on track to occur in Q4 2024 and Q1 2025 with final contract
21 awards contemplated for later in 2025.

- 22
- 23 • Stakeholder Engagement: NS Power, in coordination with NB Power, has continued its
24 stakeholder engagement process with outreach to stakeholders, special interest groups and
25 municipalities in which the projects will be constructed in both provinces. NS Power
26 continues to meet with stakeholder groups (for example, the blueberry industry) to provide
27 information about the planned work and how they may be affected.

- 28
- 29 • Project Right of Way (ROW): Progress on land easements and rights of way in Nova Scotia
30 is progressing as planned and reaching completion. NB Power is on track to ramp up project
-

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1 work related to land easements and rights of way for the New Brunswick portion of the
2 line in late 2024.

3
4 Key preliminary engineering activities continue on the Project and NS Power anticipates bringing
5 forward a capital application in Q1 2025.

6
7 **6.3.2 Stage 2**

8
9 The 2030 Clean Power Plan notes the potential for the Reliability Tie to incorporate a Stage 2
10 transmission build from Salisbury NB to Point Lepreau NB, to enable greater access to New
11 Brunswick, New England, and Quebec energy imports and exports. This extension would also be
12 accompanied by additional upgrades within Nova Scotia such as the conversion of L-7018 230 kV
13 line to 345 kV (120H-Brushy Hill to 67N-Onslow) and additional transformation capacity at 67N-
14 Onslow. This approach is consistent with IRP Action Plan Item 1b that identifies the need to
15 continue working with neighbouring jurisdictions in support of opportunities for regional
16 integration and was also identified in the Province of New Brunswick's report, *Powering our*
17 *Economy and the world with Clean Energy – Our Path Forward to 2035*.¹⁹

18
19 Future studies for Stage 2 are anticipated to include detailed engineering and economic studies for
20 firm import options requiring new transmission investment and strengthened regional
21 interconnections. This work is anticipated to continue in 2025 in parallel with the development of
22 the Reliability Tie from Onslow NS to Salisbury NB.

23

¹⁹ <https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/energy-energie/GNB-CleanEnergy.pdf>

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6.4 Fast-Acting Generation

The 2030 Clean Power Plan identifies a need for up to 600 MW of new fast-acting generation by 2030. The need for new fast-acting generation capacity was also confirmed in the Evergreen IRP analysis and it was included as part of Action Item #3c in the August 2023 update to the IRP Action Plan and Roadmap. The IRP Action Plan is clear that a significant increase in system firm capacity is required to maintain supply reliability while meeting growing peak demand requirements and replacing firm capacity that will be retired to comply with the 2030 coal phase-out policy requirements.

6.4.1 Project Approach & Next Steps

NS Power had been developing a fast-acting generation project through 2024 in alignment with both the 2030 Clean Power Plan and the IRP Action Plan. Site selection was developed, milestone schedules, initial cost estimates, and interconnection Feasibility Studies were completed.

In a meeting on September 27, 2024, the Department of Natural Resources and Renewables informed NS Power that the responsibility for procurement of all new fast acting generation will be that of the NSIESO, including responsibility for the first 300MW of generation. NS Power is currently in discussion with the Department on how project elements may be transferred to the NSIESO, including appropriate cost recovery.

6.5 Fuel Conversions at Existing Units

The 2030 Clean Power Plan includes alternate fuel operation at four of NS Power's existing thermal units. Similarly, the Evergreen IRP identified that alternate fuel operation at four units was a common resource plan element across IRP scenarios, and these were included in the IRP Action Plan under item #3e.

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6.5.1 Gas Conversion at Point Tupper Generating Station

In all scenarios modeled as part of the Evergreen IRP, the coal-to-natural-gas conversion of Point Tupper Generating Station Unit 2 (150 MW) was observed as a common outcome. This converted unit is shown to be operated in a peaking capacity (with low annual capacity factors) during periods of net peak demand to support system reliability and to meet customer demand. NS Power will be progressing the completion of the coal to gas conversion by 2028 in alignment with the phase-out of coal generation for the Point Tupper unit and the Clean Power Plan.

The coal-to-gas conversion was also a finding of the 2020 IRP and demonstrated value to the system in a peaking capacity. As a result (and reflected in the 2020 IRP roadmap), a coal-to-gas conversion project was initiated and engineering design/economic assessment work was completed to further evaluate the project scope and value. In parallel, NS Power continued to evaluate options for supply of natural gas to the site. This work will serve as a starting point for the advancement of the coal-to-gas conversion project.

To enable the coal-to-gas conversion by 2028, the NS Power team is developing milestones and project timelines for engagement, the regulatory process, and design/commissioning. This work will continue in 2025.

6.5.2 HFO Operation at Lingan Generating Station

Transition to the peaking use of Heavy Fuel Oil (HFO) for Lingan units 1, 3 and 4 (approximately 450 MW total) was identified in the 2030 Clean Power Plan. It was also a consistent outcome across all Evergreen IRP scenarios. This was a new finding as compared to the 2020 IRP, the value of which is supported by the low capital cost (these units already operate on HFO) and the ability for these units to operate in a peaking capacity during periods of net peak demand.

The timing for the transition to heavy fuel oil for Lingan 1, 3 and 4 was a consistent outcome of the Evergreen IRP as well (2028-2030) and is in alignment with the timing of the phase-out of coal

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1 generation for the three units. It is also consistent with the recognized need for dispatchable
2 capacity, including both gas and liquid fueled units, which was acknowledged as part of the
3 development of the draft CER.

4
5 To achieve the necessary timing to enable the 2030 plan, the NS Power team is developing
6 milestones and project timelines for engagement, the regulatory process, and
7 design/commissioning. Due to the timing of these conversions, no significant activity is
8 anticipated to be undertaken in 2025.

9
10 **6.6 Coal Generation Phase-Out**

11
12 The significant addition of new resources described above is designed to both enable coal phase-
13 out and support the forecast of continued load growth on the system. In parallel with these resource
14 additions, NS Power analyzed the timing of coal unit retirement and conversion as part of the
15 Evergreen IRP process in 2023. The IRP scenarios determined it was optimal to retain coal units
16 for firm capacity as late as the model allows with retirements and/or fuel switching occurring later
17 in the 2020s.²⁰

18
19 The coal unit retirement and phase-out dates provided in the 2024 10-Year System Outlook
20 represent NS Power's best estimate of when sufficient new resources will be added to the system
21 to offset retiring coal capacity, support increasing firm demand, and maintain supply reliability for
22 customers. The retirement dates in the 2024 10 Year System Outlook were pushed out for a couple
23 of units in part due to the increase in forecast firm demand in the 2024 Load Forecast and the need
24 to retain sufficient generation capacity to meet this demand. These updates include aligning the
25 retirement of Lingan 2 and Trenton 5 with the first round of new fast acting generation additions
26 and aligning the retirements of Trenton 6 and Point Aconi with the second round of fast acting
27 generation additions. These dates are summarized in **Figure 8** below.

28

²⁰ [Nova Scotia Power Evergreen IRP \(nspower.ca\)](https://www.nspower.ca); page 6

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Figure 7 – Coal Retirement and Conversion Dates as reported in the 2024 10-Year System Outlook Report

Unit	Initial The Path to 2030 Forecast	2024 10YSO Update	Notes
Lingan 1	2029	2029	Converted to HFO operation (reliability resource)
Lingan 2	2025	2027	Currently operating in Cold Reserve
Lingan 3	2029	2029	Converted to HFO operation (reliability resource)
Lingan 4	2029	2029	Converted to HFO operation (reliability resource)
Trenton 5	2027	2027	
Trenton 6	2028	2029	
Point Aconi	2028	2029	
Point Tupper	2028	2028	Converted to Gas operation

The dates provided above will continue to be evaluated as the timing of new resources, forecast for demand growth, and policy factors continue to change in the future. Updates will continue to be provided in the annual 10-Year System Outlook report.

As new firm capacity resources are added to the system, retaining existing thermal units in cold reserve can support commissioning, testing and establishment of reliable operations without compromising the system's planning reserve margin requirements. This will be considered and assessed as plans for new resources are progressed.

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7.0 ADDITIONAL IRP ACTION PLAN AND ROADMAP ITEMS

In addition to the items identified in the 2030 Resource Development Plan, there are other elements of the broader IRP Action Plan which have specific and significant impacts on resource development requirements to 2030. These are highlighted below.

7.1 Demand Side Management

In September 2022, EfficiencyOne (E1) received approval for an investment of \$173.1 million for its 2023-2025 DSM Plan activities. The plan targets 412.7 GWh and 78.8 MW in energy efficiency (EE) savings over the three-year period, and 17.9 MW of available capacity from demand response (DR) programming by the end of 2025. In its Enabling Strategies component, E1 plans to support electrification strategy development. In November 2022, the Government of Nova Scotia passed amendments to the *Public Utilities Act* under Bill 228.²¹ The amendments included replacing references to “energy efficiency and conservation activities” with “demand-side management,” and expanding the definition of “demand-side management” to include “strategic electrification of energy end uses [...]” under Section 79A(b). Bill 228 also prescribed five-year terms for DSM purchase agreements and portfolio-level evaluation of proposed cost-effective DSM programs.

Given that DSM activities have expanded outside traditional energy efficiency, achievement of current planned investments in 2023 to 2025, and development of DSM investments in alignment with the Base DSM profile identified in the Evergreen IRP, are increasingly important to achieving the 2030 decarbonization goals.

In 2024, E1 began its 2026-2030 DSM Plan development in consultation with the Demand Side Management Advisory Group (DSMAG). In tandem, the DSMAG has been consulted on the review of the jurisdictional cost-effectiveness test and framework, and NS Power engaged with the DSMAG to update the avoided costs, using modeling built on NS Power’s 2023 Evergreen

²¹ S.N.S. 2022, c. 53.

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1 IRP analysis. In December 2024, E1 will provide Round Two 2026-2030 DSM Plan model results
2 for DSMAG review and consideration. NS Power continues to review and engage with the
3 DSMAG on the development of the 2026-2030 Plan; it is anticipated that this will lead to an
4 application before the NSUARB in 2025. NS Power's focus in reviewing the plan will be
5 affordability, peak mitigation, traditionally underserved customers and strategic electrification.

6
7 **7.2 Hybrid Peak / Load Management / Demand Response**

8
9 As a component of NS Power's development of its electrification strategy report, it worked with
10 its consultant Energy and Environmental Economics (E3) to prepare load and system peak load
11 forecasts for various heating electrification scenarios. Of the heating electrification load profiles
12 considered, the hybrid peak electrification profile emerged as an opportunity for reduction of
13 system peak load requirements and was studied as part of the Evergreen IRP. This scenario
14 assumes the adoption of mini-split heat pumps along with the retention of existing back up heating
15 sources (such as oil and natural gas) to operate during the colder/peak system demand periods in
16 the winter when heat pumps are less efficient. This potential program was discussed in NS Power's
17 2023 Load Forecast Report; additional details are available as part of E3's report *The Economics*
18 *of Electrification in Nova Scotia* which was shared with stakeholders via NS Power's IRP website
19 on December 8, 2023.²² The Evergreen IRP assumptions for this program incorporate a firm peak
20 reduction of approximately 100 MW by 2030.

21
22 To fully assess the value of the hybrid peak scenario, NS Power is committed to participating in
23 study work to determine the corresponding cost impacts of potential customer programs (please
24 refer to the Action Plan Item 4b). This study, with engagement and participation from multiple
25 organizations including NS Power, will provide a balanced assessment of the cost impacts of the
26 hybrid approach and provide the necessary information to conduct a more refined assessment of
27 the program from an electricity system cost perspective.

28

²² [The Economics of Electrification in Nova Scotia \(nspower.ca\)](https://www.nspower.ca)

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1 In the first half of 2024, NS Power met with NRR on their approach to a Hybrid Peak study as part
2 of the Load Management initiative of the Clean Power Plan. Net Zero Atlantic initiated a study to
3 examine Hybrid Peak options in the fall of 2024 on behalf of NRR. The study will include key
4 stakeholders within the province including E1 and organizations representing fossil fuel heating
5 sources used in Nova Scotia. NS Power has agreed to complete resource planning modeling in
6 support of the study objectives. NS Power understands that the current estimated timeline for
7 completion of the study is Q3 2025.

8
9 In addition to the electrification strategy, the outcome of the 2020 IRP also pointed to the value of
10 DR programming to reduce peak load requirements. NS Power (with support from E1) is
11 progressing DR pilot programming with the intent of developing 75 MW of DR peak load
12 reductions. This includes work in the areas of direct load control for residential, commercial, and
13 industrial classes as well as NS Power's ongoing time varying pricing pilot program.

14
15 On September 23, 2024, NS Power received approval for its 2024/25 TVP Tariffs (M11822)
16 inclusive of a new multi-unit residential building (MURB) time-of-use (TOU) pilot tariff.
17 Recruitment for the 2024/25 season is in full swing, targeting 13,000 participants across Domestic,
18 Small General, and General TOU and critical peak pricing (CPP) tariffs, and 1,000 units for the
19 MURB TOU Pilot Tariff. The stakeholder engagements for the 2024/25 season kicked-off on
20 November 27, 2024, beginning with an online session covering the Year Three Evaluation Report
21 (M11823) and draft work plan (2024/25 Areas of Focus) for stakeholder review and comment.

22
23 During the Winter 2023/2024 period, DR events were scheduled by NS Power through E1's Smart
24 Synergy Commercial & Industrial Aggregator DR program and new Eco Shift DR pilot program.
25 2023/24 season enrollment, as presented in E1's Q2 2024 Demand Side Management Report,²³
26 totaled 77 participants in the Smart Synergy program and 350 participants (1,257 smart thermostats
27 and 48 electric vehicles) in the Eco Shift pilot. Recruitment is underway for the 2024/25 season,
28 which includes additional Eco Shift eligible bring-your-own devices (mini split heat pump smart

²³ Q2 2024 Demand Side Management Report, filed by E1 on Aug 26, 2024 to the NSUARB, Page 19-21.

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1 thermostats and residential batteries). The direct-installation water heater controller program that
2 was paused for the 2023/24 season has been integrated into the Eco Shift pilot as a direct-
3 installation water heater controller offering for the 2024/25 season.

4
5 Additionally, NS Power recently completed its Smart Grid Nova Scotia (SGNS) project,
6 submitting its final report to the NSUARB on March 15, 2024 (M11621). Following a Board
7 established written hearing proceeding regarding the report, the NSUARB provided its decision
8 letter on October 28, 2024. The Board directed NS Power to proceed with the development of a
9 DER integration roadmap with engagement from stakeholders and to file a progress update report
10 no later than December 31, 2024. In the Company's update letter of November 15, 2024 regarding
11 that matter, NS Power advised that it supports a stakeholder engagement process led by the
12 Company. The results of the SGNS project demonstrate potential benefit in several areas regarding
13 DER monitoring and management through a centralized DERMS platform, including with
14 applicability to DR programming. The Company is considering future full-scale deployment
15 options of DER with DERMS initiatives and programming, which may contribute to achieving
16 DR targets alongside price signalling options such as the pilot TVP rates.

17
18 Updates on DR program development will continue to be provided as part of NS Power's IRP
19 Action Plan reporting.

21 **7.3 Green Hydrogen Projects**

22
23 NS Power has had discussions with multiple potential green hydrogen project developers to
24 understand their requirements and provide information about the Nova Scotia power system.
25 Currently, NS Power is working with three project developers, EverWind Fuels (EWF), Bear Head
26 Energy (BHE) and Simply Blue Group to assess their needs from both an operational and tariff
27 perspective. EWF and BHE intend to produce green hydrogen primarily for export, while Simply
28 Blue Group is looking at the production of green hydrogen as a feedstock for sustainable aviation
29 fuel and renewable methanol.

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Since The Path to 2030 resource plan described in this document is based on a load forecast that does not include additional capacity or energy requirements to support these large load customers, incremental resources to meet both the firm load and renewable energy needs of the developers will be required. Given the timelines and the significant load requirement, the following outlines the common approach by the developers:

- Developers will self-develop and supply renewable resources including a mix of wind, solar and battery storage (depending on the developer).
- Developers will require interaction with the Nova Scotia power grid under a new tariff structure for the following:
 - Top up in hours when their self supplied resources do not meet their firm load requirements or, in some cases, when additional resource are required to meet their load factor. Firm load requirements range between 35MW and 100MW for the prospective developers.
 - Energy sales when their self supplied resources exceed their load requirements and these additional resources are a benefit to NS Power customers.

An assessment of this within the context of the 2030 resource plan and beyond is in progress and will be continue as NS Power's understanding of future hydrogen project development potential progresses. In addition, to ensure that any future developments related to hydrogen development in the province are monitored and assessed, NS Power included Roadmap Item 11 (Hydrogen Tariff Impacts) to enable the assessment of the tariff impacts on the Action Plan as they develop.

On December 15, 2023, the Province of Nova Scotia released its Green Hydrogen Action Plan.²⁴ The plan includes seven goals and 23 actions to help develop the sector in alignment with the Province's climate change goals. It will support both domestic use and export of green hydrogen. The plan also identifies green hydrogen as a potential complementary fuel source for the electricity

²⁴ <https://novascotia.ca/green-hydrogen/docs/green-hydrogen-action-plan.pdf>

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system that can help meet peak or emergency demand consistent with the Province's Clean Power Plan.

7.4 Offshore Wind

In September 2022, the provincial government announced a goal of leasing 5 GW of offshore wind by 2030, with specific emphasis on supporting the green hydrogen industry. Seabed lease rights for commercial scale projects are expected to be made available via a competitive commercial process beginning in 2025. First energy delivery is not currently anticipated until after 2030.

With development timelines that currently extend beyond 2030, offshore wind does not play a role in the 2030 Clean Power Plan. Offshore wind could play a part in the future of Nova Scotia's energy mix, with several paths to market available to the industry:

1. Provincial demand for clean electricity or green fuels, particularly as post-2030 renewable energy demand may increase in connection with economy-wide decarbonization.
2. Regional/national demand for clean electricity or green fuels under Canada's 2035 Clean Electricity Standard, in combination with significant transmission system expansion.
3. Demand for clean electricity from the United States.
4. International demand for low carbon, green fuels and chemical feedstock.²⁵

Given the potential installed capacity (5 GW) and market opportunities for offshore wind, NS Power continues to monitor industry and local developments to inform future planning exercises.

In 2024, Net Zero Atlantic initiated the Atlantic Canada Offshore Wind Grid Integration and Transmission Study.²⁶ The study is understood to have a 3-year timeframe (March 2024 to March 2026) with three main phases of work. This study will develop a thorough understanding of the opportunities and challenges for integrating OSW into the Atlantic Canadian grid, both

²⁵ [offshore-wind-roadmap.pdf\(novascotia.ca\)](https://offshore-wind-roadmap.pdf(novascotia.ca))

²⁶ <https://netzeroatlantic.ca/research/atlantic-canada-offshore-wind-grid-integration-and-transmission-study>

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1 provincially and regionally (from both a domestic and export lens). NS Power is participating in
2 the study; the scope of work completed in 2024 included supplying data to support the
3 development of input assumptions and scenarios that will be used by Net Zero Atlantic and their
4 partners as part of the ongoing modeling.

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**8.0 PROJECT ACCOUNTABILITIES, COORDINATION, AND RISK
MANAGEMENT**

NS Power believes that the Nova Scotia 2030 Clean Power Plan is a comprehensive and appropriate clean energy transition plan. It is based on extensive studies and stakeholder engagement.

8.1 Project Accountabilities

Figure 9 below summarizes the role of NS Power and the Province of Nova Scotia in each of the major projects/elements of the 2030 Clean Power Plan. Overall, the NS Government is responsible for the renewable energy projects and load management to meet 2030 RES targets. NS Power is responsible for fuel conversions for existing generation units, transmission and supporting infrastructure to meet off coal targets, and integration of the procured renewable energy.

There are several changes to the figure this year reflecting changes in the Nova Scotia electricity planning landscape that occurred in 2024:

- As described in **Section 5.2.1**, future Battery Storage projects will be scoped and procured by the NSIESO.
- As described in **Section 5.4.1**, all Fast-Acting Generation projects will be procured by the NSIESO.
- The NSIESO, they will be responsible for future renewable energy procurements, if needed, following the completion of the Green Choice Program and Community Solar procurements that are currently underway.

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1 Figure 8 – Project Accountabilities Matrix

2030 Projects	Accountability	NS Power Key Action Items	NS Government Key Action Items	Partner Key Action Items
Wind/Solar	NS Government	- Develop and own grid integration assets for projects serving base customers. - Complete interconnection studies and assets.	- Procure renewables from IPPs to reach RES targets. - Transition future procurement responsibilities to NSIESO.	IPPs develop, construct, and operate renewable projects.
Battery Storage	NS Government and NS Power	- Procure and finance 150 MW / 600 MWh storage through utility regulated model including competitive procurements for required products and services. - Integrate IPP energy storage projects into NS Power's	Transfer of procurement responsibilities to NSIESO.	- NSIESO to procure additional Energy Storage resources. - IPPs develop, construct, and operate additional grid-scale storage.

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2030 Projects	Accountability	NS Power Key Action Items	NS Government Key Action Items	Partner Key Action Items
		processes and operations. Complete interconnection studies and assets.		
Grid Stability and Renewable Integration Resources	NS Power	- Continue to identify required assets through IPP renewable project siting and detailed system studies. - Procure and finance through utility regulated model including competitive procurements for required products and services.	Coordinate preferred IPP project siting based on detailed system studies. Incorporate into procurement processes.	IPPs develop renewable projects in compliance with NS Power's Transmission System Interconnection Requirements (TSIR)
Hybrid Peak / Load Mgmt.	NS Government	Provide detailed load studies and forecasts.	Deliver load management initiatives through	E1 and other partners to support peak management,

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2030 Projects	Accountability	NS Power Key Action Items	NS Government Key Action Items	Partner Key Action Items
		- Participate in broader sector study on Hybrid Peak opportunity. - Collaborate in development of load management initiatives.	policies and program tools.	demand response, and efficiency programming. Net Zero Atlantic to complete Hybrid Peak study.
Reliability Tie	NS Power	- Procure and finance through utility regulated model, including competitive procurements for required products and services. - Continued engagement with NB Power on Stage 2 to Point Lepreau.	- Ensure coordinated review and issuance of required authorizations. - Advocate for federal support and funding. - Continued engagement with NB Government on extension to Point Lepreau.	NB Power to complete work to enable transmission connection to Salisbury, NB.
Fast-Acting Generation	NS Government	Per direction from Natural Resources and	Ensure coordinated review and	NSIESO to procure required Fast-

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2030 Projects	Accountability	NS Power Key Action Items	NS Government Key Action Items	Partner Key Action Items
		Renewables, NS Power is no longer responsible for the project and is to transfer all relevant project-related work developed to-date to NSIESO. Complete interconnection studies and assets.	issuance of required authorizations. Development of project procurement process and transfer of procurement responsibilities to NSIESO.	Acting Generation resources in alignment with required timelines.
Fuel Conversions	NS Power	Procure and finance through utility regulated model including competitive procurements for required products and services		

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8.2 Implementation Coordination

The Province of Nova Scotia and NS Power are both committed to meeting 2030 coal phase-out and 80 Percent Renewable Energy Standard targets. NS Power will continue to participate in a Working Group for 2030 Clean Energy Targets with the Province to support cost-effective, timely, and successful program implementation. The Working Group will ensure close coordination between provincial staff and NS Power staff to support cost-effective, timely, and successful program implementation. The Working Group will also identify enabling conditions for the plan projects.

8.3 Risk Management

Delivering on The Path to 2030 will require significant capital investments and new programs over the next six years. Risk management will be integral to implementation and reaching the 2030 environmental policy goals. Individual projects/elements of the plan will be implemented with detailed risk identification and mitigation strategies.

Last year's The Path to 2030 report identified six industry wide risks to be monitored and addressed as we progress towards 2030. These risks are summarized below, and details have been added to identify how these risks are trending relative to when they were reported in the 2023 report.

1. Supply Chain

- 2024 Trend: No change
- There continues to be constraints in the global electricity industry supply chain due to factors such as high demand/capital build-out for both electricity supply and load facilities across the industry, extreme weather and other one-time events, general inflation, and geopolitical events. This is leading to longer lead times, price increases and volatility, and lack of equipment availability.

2. Inflationary Cost Pressures

- 2024 Trend: Reduced risk

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-
- Inflation has been easing in North America over the last 12 months, with future cuts to the Bank of Canada and the US Federal Reserve overnight interest rates expected. Although inflation indices have been declining, future inflation can lead to project cost risk and cost uncertainty as suppliers refrain from providing long-term price commitments or require indexed price commitments.

3. Human Resources

- 2024 Trend: No change
- The electricity industry continues to face a shortage of talent due to high demand in both the electricity industry and adjacent industries, such as housing and other construction. This is leading to cost pressures, staffing challenges, and ultimately project delays. Talent shortages have the potential to affect NS Power, its partners across the province, and its contractors and suppliers.

4. Project Approvals

- 2024 Trend: No Change
- The 2030 Clean Power Plan requires the approval of large, capital-intensive projects such as IPP wind deployment and NS Power transmission builds. These projects will need clear First Nations, Community, and Stakeholder support to receive environmental approvals. IPP projects will require interconnection facility approvals and inclusion in fuel cost recovery. NS Power projects will require regulatory approval for cost recovery within electricity rates.

5. Transition Planning

- 2024 Trend: Increasing Risk
- The electricity load in Nova Scotia is expected to continue to grow and the comparative cost of potential supply resources will continue to shift over time. In the 2024 Load Forecast report the forecast firm peak for 2025 increased by 108 MW compared to the forecast in the 2023 Load Forecast report. This increase in forecast firm peak delays the retirement of any coal generation until replacement capacity is added to the system and pulls forward the expected timeline for generation capacity additions post 2030.

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1 6. Evolving Policy Landscape

- 2 • 2024 Trend: Reduced Risk

- 3 • As the development of the Clean Electricity Regulations progressed in 2024, clarity
4 on what the final regulation will look like improved, and on September 16, 2024,
5 the Federal Government announced that a common understanding was achieved
6 with the Government of Nova Scotia on the CER: the future CER will provide
7 flexibilities to enable system growth and support decarbonization in the Province
8 while ensuring reliability for customers. Other areas where policy changes could
9 impact system planning through 2030 (and beyond) include North American
10 Electric Reliability Corporation (NERC) and Northeast Power Coordinating
11 Council (NPCC) criteria and requirements as well as provincial and federal policies
12 related to electrification (which influences load forecasts). NS Power will continue
13 to be responsive to changes in the policy landscape via its IRP Roadmap.

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9.0 CONCLUSION

The Nova Scotia 2030 Clean Power Plan is a comprehensive clean energy transition plan that is aligned with NS Power's most recent IRP Action and Roadmap update. Delivering on this plan will require significant investments, program activities, engagement, and coordination across multiple parties including NS Power, the Provincial Government, renewable procurement administrators, third party IPPs, Mi'kmaw Partners, community groups, E1, and the NSIESO over the next five years to achieve the plan.

Pursuant to NS Power's accountabilities under the matrix provided in **Figure 9**, the Company understands its obligations in delivering the associated capital investments, customer programs, and in assisting other parties in satisfying their respective obligations where applicable. NS Power will continue to participate in a Working Group for 2030 Clean Energy Targets with the Province to support successful program implementation. The Working Group will also identify enabling conditions for the plan projects.

NS Power and the Province are in alignment on what must be done to reach 2030 Decarbonization Goals, and that the Province's 2030 Clean Power Plan provides clarity on those requirements and responsibilities. The addition of the NSIESO and NS Energy Board will introduce new stakeholders to assist with reaching Nova Scotia's decarbonization goals. NS Power is committed to supporting the transition of accountabilities to the NSIESO in collaboration with NRR.

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Request IR-4:

The following directive has been issued by the Board since the last general rate application with a bring forward date for the next general rate application (and was not outlined in Appendix 3A). Please outline how this directive has been addressed in the current application:

(a) M11598 - Nova Scotia Power Inc. - CI C0041506 – LM6000 191-253 Major Engine Refurbishment

(i) In its upcoming depreciation study, NS Power is also directed to describe how the costs of the 191-253 engine refurbishment were considered in setting depreciation rates, and to estimate the rate impact of any proposed adjustment to the depreciation rates for the unit.

Response IR-4:

(a) The undepreciated cost of prior LM6000 major engine and hot section refurbishments as of December 31, 2023 are included in the required future accruals for Tufts Cove CT Unit 4 and Tufts Cove CT Unit 5.¹ The required future accruals, which include the net book value and expected future net salvage associated with these units as of December 31, 2023 are divided by the composite remaining life for the units to calculate an annual accrual requirement. The annual accrual requirement is divided by the gross book value of the units to determine the proposed depreciation rate. The company did not include an estimate of the rate impact as part of the Application, but it has been included in response to NSEB IR-5.

¹ M12451, NS Power 2026 General Rate Application, Exhibit N-7, Gannett Flemming NS Power Depreciation Study, Appendix 8A, section VI-4, page 58 of 297.

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Request IR-5:

(a) Related to the directive in IR-4, please explain how NS Power considered the costs of the LM 191-332 engine refurbishment and LM 191-443 engine replacement (Matter M12416) in setting depreciation rates.

(b) Please identify the estimated rate impacts of any proposed adjustment to the depreciation rates for the units.

Response IR-5:

(a) The costs associated with the LM6000 191-332 Life Extension and LM6000 191-443 Engine Replacement were not considered in setting depreciation rates as the required future accruals were determined as of December 31, 2023. Excluding forecast future capital investment is consistent with industry practice and NS Power's last depreciation study in which the required future accruals were determined as of December 31, 2009, with approved depreciation rates implemented as of January 2012.

(b) NS Power estimates that the proposed increase in depreciation rates for Tufts Cove Units 4 and 5 results in an approximate one-time increase in customer rates of approximately 0.2 percent.

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Request IR-6:

Please provide NS Power's reliability indices for 2019 to 2024 inclusive, including:

- (a) System Average Interruption Duration Index (SAIDI).**
- (b) System Average Interruption Frequency Index (SAIFI).**
- (c) Customer Average Interruption Duration Index (CAIDI).**
- (d) Customer Average Interruption Frequency Index (CAIFI).**
- (e) Please include a comparison with each of the other Atlantic Provinces and Electricity Canada.**

Response IR-6:

- (a) NS Power's All-In SAIDI by Year is found below:**

Year	2019	2020	2021	2022	2023	2024
SAIDI	43.88	6.57	5.60	74.87	23.03	6.34

- (b) NS Power's All-In SAIFI by Year is found below:**

Year	2019	2020	2021	2022	2023	2024
SAIFI	4.52	2.71	2.56	5.82	4.97	2.75

- (c) NS Power's All-In CAIDI by Year is found below:**

Year	2019	2020	2021	2022	2023	2024
CAIDI	9.70	2.42	2.19	12.86	4.63	2.31

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(d) NS Power's All-In CAIFI by Year is found below:

Year	2019	2020	2021	2022	2023	2024
CAIFI	4.52	2.70	2.61	5.56	5.03	3.23

(e) The Atlantic Utilities Average, Region 2 (utilities with a service territory characterized by an Urban/Rural mix, like NS Power), and All-Canada (all reporting utilities) results for 2019-2024 are provided for three of the four metrics below. CAIFI is not a metric tracked by Electricity Canada in its annual reporting and as a result no comparison with other utilities is currently available.

SAIDI	2019	2020	2021	2022	2023	2024
NS Power	43.88	6.57	5.60	74.87	23.03	6.34
Atlantic Canada	26.37	7.21	6.03	47.69	18.44	6.91
Region 2	10.74	6.70	7.01	17.08	12.59	7.82
All-Canada	8.38	5.35	5.57	14.32	9.95	6.25

SAIFI	2019	2020	2021	2022	2023	2024
NS Power	4.52	2.71	2.56	5.82	4.97	2.75
Atlantic Canada	3.67	2.86	2.79	4.52	4.18	2.77
Region 2	3.08	2.75	2.77	3.42	3.66	3.07
All-Canada	2.65	2.39	2.42	2.97	3.06	2.63

CAIDI	2019	2020	2021	2022	2023	2024
NS Power	9.70	2.42	2.19	12.86	4.63	2.31
Atlantic Canada	7.19	2.52	2.16	10.55	4.41	2.49
Region 2	3.49	2.44	2.53	4.99	3.44	2.55
All-Canada	3.16	2.24	2.30	4.82	3.25	2.38

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Request IR-7:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.2 Overview of 2026-2027 GRA

On page 10 of the application, NS Power states it has worked hard with customer representatives to balance both the reliability and affordability priorities. Please explain how reliability and affordability have been balanced in the current application. If specific investments have not been included because they were deemed to be not affordable, please identify these investments.

Response IR-7:

As outlined in NS Power's 2025 Annual Capital Expenditure (ACE) Plan (M12012) and the Five-Year Reliability Plan (Exhibit N-3), balancing the cost of improving the reliability against the benefits is a key element when considering rate impacts, and consequently future rates. In line with the approach outlined in the Five-Year Reliability Plan, the competing priorities of reliability and affordability are balanced through a focus on achievement of performance standards for reliability at a reasonable pace, over time. This approach helps to manage the impact of rates necessary to make important investments in reliability while recognizing that no system can be built to withstand every possible threat and the potentially diminishing returns of investments as reliability improves.

Balancing these competing priorities is a difficult endeavour, but is one that benefited from the collaborative approach to this consensus GRA.

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1 **Request IR-8:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 1.2 Overview of 2026-2027 GRA**

4
5 **On page 10 of the application, NS Power compares the proposed rate impacts of this GRA**
6 **to recent annual average rate increases experienced by its Atlantic Canadian neighbours.**

7
8 **(a) Please identify which utilities are referenced and the specific rate increases for each.**

9
10 **(b) Please specify whether each of these utilities also received rate increases since 2023**
11 **and compare the compound rate changes of NS Power from 2023 to the proposed new**
12 **rates with compound rate changes for the same comparator neighbouring utilities**
13 **over the same period.**

14
15 **(c) For a residential customer on a standard service offering, who consumes 10,000 kWh**
16 **per year, please compare annual rates charged and intended to be charged by NS**
17 **Power and these neighbouring utilities in 2025, 2026 and 2027, inclusive of all**
18 **applicable riders.**

19
20 **Response IR-8:**

21
22 **Response**

23
24 **(a) Please see New Brunswick Energy and Utilities Board Matters #0552 (General Rate**
25 **Application) and #0573 (Variance Account Recovery Application) for an approved**
26 **combined average rate increase of approximately 13 percent effective April 1, 2024. (New**
27 **Brunswick Power).**

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1 Please see Newfoundland & Labrador Public Utilities Board Order P.U. 16(2024) for an
2 approved average rate increase of 7.0 percent effective August 1, 2024. (Newfoundland
3 Power).

4 (b) NS Power has not performed this analysis; however, if it were to be performed care is
5 required in using 2023 as a comparator given the fact that NS Power had not sought or
6 obtained a general rate increase for nearly a decade prior.

7
8 (c) NS Power has not performed an analysis regarding a specific customer usage profile
9 compared to rate changes of neighbouring jurisdiction. The Application reflects a consensus
10 agreement with all customer representatives and provides support and justification for the
11 proposed increases for NS Power. NS Power has provided the average annual increase of a
12 domestic customer in Figure 2-1 of the Direct Evidence in the GRA.

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Request IR-9:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.2 Overview of 2026-2027 GRA

On page 10 of the application, NS Power proposed that as of January 1, 2027, compounded rate increases for residential customers would be 8.06%. Please explain how NS Power determined that an increase of 8.06% over the span of one year, from January 1, 2026, to January 1, 2027, is affordable.

Response IR-9:

The consensus outcome of the GRA proposes an overall average of 1.8 and 2.4 percent increases, in 2026 and 2027 for customers. The Board-directed and customer representative supported updated Cost of Service Study dictates how that overall increase is apportioned among customer classes. Furthermore, it is perhaps helpful to clarify that these proposed increases take place in two separate years: first in 2026, followed by an increase in 2027. There is no one time 8.06 percent increase.

As stated on page 10 of the application, NS Power has worked relentlessly to keep costs down in all aspects of its operations, as well as working with the provincial and federal governments to find ways to reduce cost pressures on customers. NS Power further describes efforts undertaken to reduce cost pressure for customers in section 1.5 of the application (page 13) and in response to NSEB IR-54.

While NS Power constantly works to reduce costs and mitigate rate impacts for customers, rate increases are required periodically to provide customers with safe and reliable electricity service. The Company understands this can present challenges for customers and this has been a key driver of the extensive collaboration with customer representatives which was undertaken in advance of this filing and which led to the Settlement Agreement which underpins this GRA.

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1 **Request IR-10:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 1.3 Customer Growth and Support**

4
5 **On page 11, NS Power notes “a significant reduction in residential disconnections (3,158 in**
6 **2023 vs. 1,782 in 2024)”. Is this the total number of disconnects in those years or is it the**
7 **number by which disconnects were reduced in those years?**

8
9 **Response IR-10:**

10
11 **This is the total number of disconnects in those years.**

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Request IR-11:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.4 Reliability and System Strength

On page 11 of the application, NS Power says it is advancing innovative large-scale capital projects that will ensure the stability of the electricity grid as Nova Scotia continues its energy transition, replacing fossil fuels with renewable energy sources at a pace that best serves Nova Scotians.

(a) Please elaborate on what NS Power means by “a pace that best serves Nova Scotians”.

(b) Please comment on this pace in light of the observations in the ScottMadden Report that NS Power’s capital employed metrics are generally at or below the peer group median (noted by NS Power on page 35 of the application).

Response IR-11:

(a) The phrase “a pace that best serves Nova Scotians” refers to the measured approach to the energy transition and reliability investment, which recognizes that the costs associated with those investments have impacts on customers and the need to balance those impacts with the need to progress energy transition and reliability projects.

(b) The ScottMadden work is helpful in that it provides data points to compare and helps validate NS Power’s expenses at a high level. However, the work does not take into account jurisdiction-specific variables such as the presence, extent, or state of an energy transition, load growth and jurisdiction specific economic and environmental factors, legislated requirements, duties or obligations, or the political environment. Such elements, when considered in the Nova Scotia context, provide context that supports the measured approach that has been taken in Nova Scotia at a pace that best serves Nova Scotians.

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Request IR-12:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.4 Reliability and System Strength

On page 11 NS Power notes that over 65 community meetings were held throughout Nova Scotia to discuss reliability and understand customer expectations.

(a) Please provide any meeting notes or summaries that were prepared to record the feedback received.

(b) In M12188 Board IR-2, NS Power noted that it committed to providing preliminary data for computing the value of lost load (VoLL) as recommended by Dr. Gonatas in M11692. Has NS Power used the feedback from the community meetings to enhance its data or modeling for the VoLL calculation?

(c) Has NS Power measured customer satisfaction with respect to reliability as a baseline to test the reliability plan against?

(i) If so,

(1) What are the quantitative measures identified at the start of the reliability plan implementation?

(2) Has any data been collected with respect to impacts on customer satisfaction of reliability efforts since the previous GRA?

(ii) If not, why not?

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1 Response IR-12:

2
3 (a) NS Power works directly with community members during the engagement sessions to
4 ensure the reliability plans for the area are informed with direct feedback from customers.
5 Topics of discussion and feedback generally are centred around planned & unplanned
6 outages, upcoming tree trimming, upcoming capital upgrade work and specific customer
7 escalations. While formal meeting notes have not been compiled, individual action items,
8 as identified during sessions, are acted upon. Follow-up is provided directly with the
9 stakeholders.

10
11 (b) No. NS Power's ongoing work on VoLL as referenced in M12188 Board IR-2 has not been
12 specifically informed by input from community meetings. These reliability engagement
13 meetings are neither intended nor designed to gather the detailed information required to
14 assess VoLL in Nova Scotia which is in progress under a different process.

15
16 (c) While customer expectations provide valuable insights, NS Power does not anticipate using
17 CSAT as a measure of the effectiveness of its Five-Year Reliability Plan. As detailed in
18 the plan itself, NS Power is focused on the achievement of performance standards and has
19 designed its investment tracks accordingly. NS Power anticipates that CSAT related to
20 reliability concerns will be positively impacted by such investments by delivering
21 decreased outage frequency and duration, but CSAT is not considered a consistent and
22 repeatable reliability metric for benchmarking.

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1 **Request IR-13:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 1.4 Reliability and System Strength.**

4
5 **Please provide all data supporting NS Power's statement that it surpassed the Canadian**
6 **average for having power on in 2024.**

7
8 **Response IR-13:**

9
10 Please note that the 2023 Canadian average is 99.89 percent and not 99.73. At the time of filing,
11 the 2023 All-Canada average was the most recent comparison available from Electricity Canada
12 NS Power's 2024 average for power availability is 99.93 percent, thus NS Power's power on
13 availability in 2024 outperforms the Canadian average.

14
15 Please refer to NSEB IR-14 for the calculation of NS Power's power on availability in 2024. The
16 calculation of the average Canadian availability uses the same calculation approach.

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Request IR-14:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.4 Reliability and System Strength

On page 12, NS Power stated: In 2024, \$200 million was invested in reliability and included replacing 3,000 poles and clearing trees from 1,500 kilometers of power lines. In that same year, power was on 99.9 percent of the time, surpassing the Canadian average of 99.73 percent.

(a) How many outages were recorded in 2024?

(b) Please explain how the 99.9% was calculated.

Response IR-14:

(a) A total of 11,484 outage events (planned and unplanned) were recorded by NS Power in 2024. This number includes outages events of all sizes, ranging from events impacting a single customer up to and including full feeder outages.

(b) The availability percentage is calculated by dividing the duration of power on for the average customer by the total number of hours in the year. For Nova Scotia Power's 2024 performance, the calculation is as follows:

$$\text{Hours of Power On} = (8,784 \text{ Hours} - \text{SAIDI})$$

$$\text{Hours of Power On} = (8,784 \text{ Hours} - 6.34 \text{ Hours})$$

$$\text{Hours of Power On} = 8,777.66$$

$$\text{Power On Availability (\%)} = \frac{8,777.66}{8,784} = 99.93\%$$

REDACTED

Request IR-15:

Reference: Exhibit N-3 GRA Direct Evidence, Section 2.1 Electricity Rate Impact

On page 16, NS Power stated that it is seeking approval for a total revenue requirement of \$2.0 billion in 2026 and \$2.0 billion in 2027. Please provide NS Power's actual regulated revenues and expenditures for each year since 2020, including the forecast and actual year-to-date for 2025.

Response IR-15:

Please see table below which provides the regulated revenue and expenses (in \$ million).

	2020	2021	2022	2023	2024	2025 YTD (2)	2025 Forecast
Regulated Revenue	1,493	1,501	1,675	1,670	1,854	1,034	
Regulated Expense (1)	1,360	1,349	1,526	1,515	1,674	910	
Matter	M10080	M10547	M11090	M11662	M12227		

(1) Full year regulated revenues and expenses are filed with the NSEB on an annual basis. The regulated expenses listed includes total operating expenses, income tax expense, interest expense and other expense categories from NS Power's regulated income statement.

(2) YTD is June as of June 30 as regulated financial statements are only calculated quarterly.

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Request IR-16:

Reference: Exhibit N-3 GRA Direct Evidence, Section 9.2 Details of Rate Base

On page 52 of the application, NS Power notes that its proposed rate increases do not include costs for the Reliability Intertie project, which are expected to be recovered through a rider as opposed to NS Power's general rates.

(a) Please explain why NS Power believes it is appropriate to recover these costs through a rider.

(b) When does NS Power expect the rider to commence?

(c) What is the forecast percentage impact on average customer rates as a result of the proposed rider?

Response IR-16:

(a) NS Power believes it is appropriate to recover these costs through a rider as that is the mechanism that is contemplated in section 21B of the *Public Utilities Act*, which is the legislative provision under which Wasoqonatl Transmission Incorporated was formed for the purposes of the Reliability Intertie Project.

Section 21B(4) provides: "The revenue requirement for an ownership arrangement shall be determined by the Energy Board and recovered through an annual assessment against the public utility participant in the ownership arrangement, the amount of which may be determined by the Board." Section 21B(5) continues, stating: "A public utility is entitled to recover annually from its customers any assessment approved by the Energy Board under subsection (4)."

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1 In these circumstances, a rider is the appropriate mechanism to ensure that an assessment
2 that is being approved annually by the Board is also being recovered annually.

3
4 (b) It is anticipated the rider will commence concurrent with the current targeted in-service
5 date for the Reliability Intertie in Q4 2028.

6
7 (c) The rider is anticipated to take effect outside of the 2026-2027 test period. NS Power does
8 not have a forecast of its impact on customer rates at this time.

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1 **Request IR-17:**

2
3 **Reference: Exhibit N-5, Appendix 3A, Status of GRA-Related Deliverables**

4
5 **In Item 3, NS Power notes that it created a Climate Change Adaptation Plan in 2021.**

6
7 **(a) Please explain why, if NS Power had already created a Climate Change Adaptation**
8 **Plan when the Board issued its directive in its 2023-2024 GRA decision, NS Power**
9 **waited 20 months to file it with the Board.**

10
11 **(b) Please provide a breakdown of the deferred costs for the development of the Climate**
12 **Change Adaptation Plan included for recovery in this general rate application and**
13 **identify the amount of these deferred costs incurred on or after February 2, 2023.**

14
15 **(c) Please list all stakeholder engagements undertaken to develop the Climate Change**
16 **Adaption Plan, including when and where they were held and who attended. Please**
17 **specifically identify engagements to which parties who regularly intervene in NS**
18 **Power’s regulatory proceedings in Nova Scotia were invited to attend.**

19
20 **(d) Please explain why Appendix 3A, p. 13, item (c), shows engagement in a consultative**
21 **process to develop a Climate Change Action Plan as “in progress” if the plan has**
22 **already been created.**

23
24 **(e) Please provide details on the Climate Action Leadership Program (CALP), including**
25 **who owns or operated this program and how it is funded.**

26
27 **Response IR-17:**

28
29 **(a) NS Power did have a Climate Adaptation Plan prior to the 2023-2024 GRA Decision but**
30 **the directive required stakeholder engagement in a consultative process to develop a formal**

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1 climate adaptation plan.¹ After the directive was issued, NS Power proceeded with
2 updating the Climate Adaptation Plan submitted for the NSEB's consultation as part of the
3 M11067 NS Power Property and Asset Valuation Inquiry. The consultation process
4 primarily relied on engagement with the Climate Adaptation Leadership Program, and a
5 technical conference with intervenors was held before formally filing as part of the GRA
6 application.

7
8 (b) The operating costs associated with the development of the Climate Change Adaptation
9 Plan have already been incurred and are not included for recovery in this General Rate
10 Application. NS Power did complete a Climate Adaptation Management System Capital
11 project (CI C0024649) to deliver on components of the Climate Adaptation plan totalling
12 \$536,901.

13
14 (c) NS Power has actively participated in stakeholder engagement activities throughout the
15 development and implementation of its Climate Change Adaptation Plan. These
16 engagements were primarily conducted through the Climate Adaptation Leadership
17 Program (CALP), which was initiated in 2021 under the leadership of Nova Scotia
18 Environment and Climate Change (ECC) and later transitioned to ClimAtlantic for the
19 implementation phase (2023–2025).

20 The initial CALP kickoff session in May 2021 brought together a diverse working group
21 of stakeholders from across the electricity sector and related fields. Attendees included
22 representatives from NS Power, EfficiencyOne, Ecology Action Centre, the Municipality
23 of the County of Kings, the Department of Energy and Mines, the Emergency Management
24 Office, Bell Canada, Michelin, Natural Forces, and the Canadian Electricity Association.
25 The Consumer Advocate was an initial participant with the working group.

26 NS Power's engagement included participation in the Scan Team workshops, contribution
27 to the sector-wide climate adaptation survey, and a formal presentation of its Climate

¹ M10431, NS Power's 2023-2024 General Rate Application, NSEB Decision at para. 340, February 2, 2023.

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1 Adaptation Plan to the CALP team in October 2021. These sessions informed the
2 development of the sector-wide strategy and ensured alignment with NS Power’s internal
3 planning processes. NS Power has participated in several CALP meetings each year, and
4 during the implementation phase (2023-2025), four sub-committees have been established
5 that meet bi-weekly to advance specific CALP initiatives.

6 On March 27, 2025, NS Power hosted a dedicated session for regulatory stakeholders and
7 intervenors to present its Climate Adaptation Planning Process. The presentation provided
8 an overview of the eight-step planning framework adopted from Electricity Canada,
9 highlighted key climate risks and adaptation measures, and outlined the integration of
10 climate adaptation into NS Power’s asset management and reliability planning processes.
11 The session also included a summary of CALP’s role in supporting cross-sectoral
12 collaboration and implementation.

13 In addition to CALP-related engagement, NS Power maintains active participation in
14 several industry organizations to stay informed about utility best practices and climate
15 adaptation strategies. These include the Centre for Energy Advancement through
16 Technological Innovation (CEATI), the Electric Power Research Institute (EPRI), and
17 Electricity Canada. Through these affiliations, NS Power regularly contributes to and
18 benefits from collaborative research, benchmarking, and knowledge-sharing initiatives
19 focused on enhancing utility resilience, integrating climate data into planning, and
20 advancing adaptation technologies and frameworks.

21 These engagements reflect NS Power’s commitment to transparency, collaboration, and
22 continuous improvement in addressing climate risks and enhancing system resilience.

23 (d) Appendix 3A, page 13, item (c), refers to engagement in a consultative process to develop
24 a Climate Change Action Plan as “in progress” because NS Power had intentionally left
25 this item open pending any additional feedback or direction through the General Rate
26 Application (GRA) process.

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1 (e) Starting in 2021, the Climate Adaptation Leadership Program (CALP) was originally
2 operated under the leadership of Nova Scotia Environment and Climate Change (ECC) and
3 funded in partnership with Natural Resources Canada through the Building Regional
4 Adaptation Capacity and Expertise (BRACE) initiative. CALP was designed to build
5 sectoral capacity for climate adaptation through a five-step adaptive management cycle.

6
7 During the implementation phase from 2023 to 2025, operational leadership of CALP
8 transitioned to ClimAtlantic. Under ClimAtlantic's guidance, the program continued to
9 support the electricity sector in implementing its climate adaptation strategy, which is
10 structured around four key focus areas: Education & Engagement, Stakeholder
11 Engagement, Programs, and Decision-Making.

12
13 These workstreams include public education campaigns on storm preparedness and climate
14 resilience, the creation of a community of practice and information-sharing platforms,
15 development of recommendations for climate adaptation programs, and the formulation of
16 recommendations for regulatory integration under the Energy Reform Act. CALP, under
17 ClimAtlantic's leadership, remains a central mechanism for advancing the strategy and
18 ensuring alignment with provincial climate goals.

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Request IR-18:

Reference: Exhibit N-5, Appendix 3B Climate Adaptation Plan, p.20

In relation to the CEA climate hazard of “Changes in type, timing and intensity of precipitation” and “Major precipitation events, overland flooding and storm surges” the associated climate variable for amount of precipitation is “Total precipitation, daily”. In NS Power’s recent FAM audit process (M11533), NS Power reported that total daily precipitation data was not sufficient to demonstrate the severity of intense precipitation that had occurred over periods of 12 hours or less.

(a) Was precipitation data of less than 24 hours duration used for the climate data sets and climate risk analysis?

(i) If not, why not?

(ii) If so, where in the reports or modeling is this incorporated?

Response IR-18:

(a) Precipitation data of less than 24-hour duration was not used in the climate risk analysis conducted for NS Power’s Climate Adaptation Plan.

(i) The climate datasets selected were based on best practices for long-term scenario analysis, which typically rely on daily, monthly, and seasonal aggregations. This approach is consistent with the capabilities of global and regional climate models, which generally do not provide reliable sub-daily projections due to limitations in temporal resolution and computational intensity.

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1 Although some datasets used for analyzing past weather patterns do include hourly
2 data, the future-focused analysis relied on sources that only offer daily or coarser
3 data. Therefore, the risk assessment focused on daily total precipitation and related
4 indicators such as:

- 5
- 6 • Number of days with precipitation >10 mm, >30 mm, and >50 mm
- 7 • Standardized Precipitation Index (SPI)
- 8 • Freeze-thaw cycles
- 9 • Landslide hazard (rainfall-induced)
- 10

11 These indices were selected to characterize storm frequency, intensity, and
12 associated hazards, and were considered sufficient for asset-level risk prioritization
13 and adaptation planning.

14

15 (ii) N/A

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Request IR-19:

Reference: Exhibit N-5, Appendix 3B Climate Change Adaptation Plan, p.42

The “Develop a Business Case for Selected Measures” notes that “NS Power strives to minimize costs for customers and maximize the operating capacity and life of its assets”. It is also noted that an Economic Analysis Model may be performed where there are multiple options.

(a) It is not clear to Board staff if any economic analysis is being completed on a holistic basis. Is NS Power doing any calculations that incorporate the increased probability of major storm events and the total forecast cost of those events measured against the cost of system improvements and combinations thereof? (rather than just incorporating the increased risk into the risk assessment for individual assets)

(i) If so, please provide the analysis and explain the scenarios modeled.

(ii) If not, why not? Wouldn’t the overall costs, and probability of incurring those costs, need to be considered to minimize costs for customers?

(b) Have climate impacts already been incorporated into NS Power’s risk ranking processes?

(i) If so, when was this change made?

(ii) If not, when will it be incorporated?

Response IR-19:

(a) NS Power has actively advanced a holistic and cost-effective approach to reliability and climate resiliency through its Five-Year Reliability Plan (2025–2029), which includes \$1.3 billion in targeted investments. These investments are designed to reduce outage frequency

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1 and duration, strengthen grid resilience, and meet the Performance Standards mandated by
2 the Board.

3
4 The Plan is built on three core programs:

- 5
- 6 • Storm Hardening – Vegetation Management,
 - 7 • Storm Hardening – Targeted Equipment Replacements and Upgrades, and
 - 8 • Advanced Grid Modernization
- 9

10 These programs are expected to deliver an approximately 20 percent reduction in SAIDI
11 (System Average Interruption Duration Index), from a five-year average of 5.10 to 4.10 by
12 2029, and support achievement of the SAIFI (System Average Interruption Frequency
13 Index) target of 2.05. This projection includes consideration for climate impacts on system
14 performance from the increasing frequency and severity of weather. During the
15 development of the plan a “business as usual” approach, without the step change in
16 investment of the five-year reliability plan was anticipated to result in a gradual
17 deterioration of SAIFI and SAIDI over the long term due to worsening climate.

18
19 NS Power’s approach is guided by performance standards, which are mandated by the
20 regulator. NS Power is focused on achieving these standards in the most cost-effective way
21 possible, balancing reliability improvements with affordability for customers. NS Power
22 built the plan targeting the activities that would have highest reliability cost efficiency or,
23 in other words, the lowest cost for customers to achieve system performance standards.

24
25 The current Performance Standard framework would not support a simplified holistic
26 system-wide cost benefit analysis using the forecast costs of the outages against the cost of
27 system improvements. To meet the Performance Standards, distribution feeders are
28 prioritized for improvements based on performance (CKAIDI, CKAIFI), not comparing
29 the costs of the overall outages against the cost of improvements. If this economic analysis

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1 methodology were deployed, rural feeders would not be prioritized for reliability
2 improvements.

3
4 (i) N/A

5
6 (ii) NS Power's current approach incorporates climate-related risks into asset-level risk
7 assessments and investment prioritization decisions. In certain cases, when
8 evaluating reliability strategies NS Power incorporates the cost of reliability
9 investment against the restoration costs. For example, the cost of comprehensive
10 undergrounding (estimated in the tens of billions of dollars) would be compared
11 against the cost and impact of responding to extreme events such as Hurricane
12 Fiona (~\$114 million and significant outage impact). In that case it would not be
13 beneficial to customers to deploy this strategy based on the probability of these
14 events.

15
16 NS Power does recognize that understanding the direct cost to customers during
17 severe weather events could help with investment planning and is actively
18 exploring the integration of Value of Lost Load (VoLL) into its investment
19 planning framework. As noted in the Five-Year Reliability Plan (Section 1.2), NS
20 Power supports the approach used in other jurisdictions where customer surveys
21 are used to quantify outage impacts and inform regulatory decisions. NS Power has
22 committed to studying and reporting on the potential use of VoLL in the reliability
23 investment planning process. This work has the potential to help inform future
24 investment decisions and support a more holistic evaluation of system-wide costs
25 and benefits, including those associated with major storm events.

26
27 (b) Yes, climate impacts have been incorporated into NS Power's risk rating processes.

28
29 (i) This integration began during the development of the Climate Adaptation Plan and
30 was further embedded into NS Power's Asset Management Mechanism and risk

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1 profiles. As outlined in the Five-Year Reliability Plan (Section 4.0), climate-related
2 risks such as vegetation condition, storm exposure, and asset vulnerability are now
3 considered in prioritizing reliability investments.
4

5 (ii) N/A

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1 **Request IR-20:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence**

4
5 **On page 12 of the application NS Power states that it plans to spend \$485 million in 2026 and**
6 **2027 and lists several proposed projects on page 12 and 13.**

7
8 **(a) Please confirm that the \$485 million and the listed projects are part of the Five-Year**
9 **Reliability Plan filed by NS Power in the 2025 ACE Plan (Matter M12012).**

10
11 **(b) Please file a copy of the Five-Year Reliability Plan in this proceeding.**

12
13 **(c) Please provide the estimated project costs for each of the projects in the bullets on**
14 **page 12 and 13.**

15
16 **(d) Are any of the proposed projects listed on pages 12 and 13 expected to be in-service**
17 **in the test years? If so, please identify which projects.**

18
19 **Response IR-:**

20
21 **(a) Confirmed.**

22
23 **(b) Please refer to Attachment 1.**

24
25 **(c-d) Please refer to the table below that lists each of these projects, their estimated costs and the**
26 **year they are expected to be in service.**

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Initiative	Cost (\$ Million)	In- Service Date
New high voltage protective device to reduce outages between Middlefield and Maitland Bridge.	3.0	2026
New Bridgewater substation to support load growth.	10.0	2027
Subsea cable replacements for Brier Island and upgrading targeted power lines in the area.	4.0	2027
New Stellarton substation and transformer replacements to support load growth and upgrade infrastructure.	13.0	2026
Smart Grid upgrades in Pictou East for improved communications and switching.	0.5	2027
Reduce planned outages in Amherst area through upgrading the switching capacity of the power system.	2.0	2027
Smart Grid enhancements to in Cape Breton to allow for quicker response to power outages by pinpointing the location of the cause for 5,500 customers, including Eskasoni First Nations.	2.4	2026
Multiple voltage conversions in Sampsons Cove and Arichat areas to upgrade assets and support load growth.	1.25	2026
Transformer replacements in Glace Bay and Aberdeen to upgrade existing infrastructure.	Glace Bay – 4.0	2027
	Aberdeen - 2.0	2026
New Bayers Lake substation to support load growth	15.0	2027
Smart Grid enhancements to allow for quicker response to power outages by pinpointing the location of the cause for Lakeside, Hammonds Plains, and Kearney Lake communities.	1.3	2026
Adding a second circuit for 4.5 km along Peggy’s Cove Road to address customer load issues	2.0	2026

Nova Scotia Utility and Review Board

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

Five-Year Reliability Plan 2025-2029

Nova Scotia Power

December 20, 2024

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1.0 INTRODUCTION

NS Power’s top priority is delivering safe, affordable, and reliable electricity every day to power customers’ homes, businesses, and communities. The Company is committed to improving the reliability and resiliency of the power grid and has developed a Five-Year Reliability Plan (the Plan) detailing \$1.3 billion of investments in reliability programs. Informed by an in-depth analysis of outage causes, the Plan focuses on investments in the transmission and distribution systems through three core programs outlined below:

1. Storm Hardening - Vegetation Management,
2. Storm Hardening – Targeted Equipment Replacements and Upgrades, and
3. Advanced Grid Modernization

As the impacts of climate change have intensified over the past 10 years, NS Power has responded with \$1.8 billion in system infrastructure investments over that period. It has enhanced its organizational structure to place greater focus on reliability improvements through the creation of a Reliability Team responsible for the implementation of reliability-driven work to reduce the duration and frequency of outages for customers.

In the Board’s decision on the 2023 Annual Performance Standards (M11624), the Board directed the following:

...that a comprehensive written version of NS Power’s five-year reliability plan is needed to understand how service improvements will be achieved and against which progress in achieving the performance goals can be tracked. This plan must include specific actions and related timing, demonstrate why these specific investments were selected and quantify the level of reliability or resilience improvement expected from each investment.

In response to the Board’s directive, NS Power has prepared this version of its Plan to provide the Board and Stakeholders with:

- A synopsis of what is causing the reliability challenges,
- A detailed plan with targeted reliability investments to mitigate the risks associated with the impacts of escalating weather events, and
- An overview of the expected improvements in reliability for customers as NS Power executes this Plan.

As shown in **Figure 1** below, NS Power’s Plan includes approximately \$1.3 billion of investment over the 2025-2029 period. This work will result in a more reliable and resilient grid that is better able to withstand and bounce back when the power system is operating under moderate levels of stress, and to a certain extent also from extreme weather events like hurricanes. This level of investment is approximately 12 percent more than the level of investment in the transmission and distribution system over the past five years (2019-2023).

Figure 1: Forecast Investment by Reliability Program 2025-2029 (\$ million)

Reliability Program	2025	2026	2027	2028	2029	Total Plan
Storm Hardening - Targeted Equipment Replacement and Upgrades	152.4	181.1	198.7	192.4	191.8	916.4
Storm Hardening - Vegetation Management	45.0	45.0	45.0	65.0	65.0	265.0
Advanced Grid Modernization	9.2	7.9	7.9	15.3	37.6	77.9
Total	206.6	234.0	251.6	272.7	294.4	1,259.3

1.1 Goals of the Plan

The reliability and resilience investments included in this Plan are aimed at achieving the following two overarching goals:

1) **Improve the customer reliability experience by reducing SAIDI by 20 percent from the current five-year average of 5.10 and achieving the Performance Standards SAIFI target of 2.05.¹**

2) **Continue to strengthen grid resilience to address climate change and achieve the Performance Standards for restoring service to customers within 48 hours after a Major Event.²**

NS Power's reliability programs are designed to enhance reliability while also making the grid more resilient to the impacts of climate change and increasingly severe weather events.

The investments outlined within the Plan will make the power system more resilient for all weather events. Storms with wind gusts exceeding 100 km per hour, like Hurricane Dorian (2019), Hurricane Fiona (2022) and Hurricane Lee (2023), will continue to challenge the reliability and resilience of the power system. However, this Plan is designed to reduce the overall impact of significant storms and improve restoration times.

Section 3 of the Plan outlines the forecast investment levels for each program and highlights the estimated benefits of NS Power's reliability programs.

1.2 The Economic Value of Outages

NS Power acknowledges the Board's direction in its Decision on NS Power's Storm Cost Recovery Rider Application,³ that evaluating the Value of Lost Load (VoLL) by customer classes could provide valuable support for investment decisions. NS Power believes that assessing the specific economic impacts of customer outages must be tailored to Nova Scotia and derived through

¹ All references to SAIDI in the Plan reflect Performance Standards SAIDI, which excludes MEDs and EEDs. A 20% reduction in Performance Standard SAIDI from the current five-year average of 5.10 results in a Performance Standards SAIDI of 4.10 by the end of 2029. The Performance Standards SAIDI metric is set at 4.29 for 2024.

² A Major Event is defined as a significant weather-related or other disruptive event that results in at least one Major Event Day (MED). MED and other key terms are defined in Appendix 1.

³ M11692 2025 Storm Cost Recovery Rider (SCRR)

customer engagement. In other jurisdictions in the United States and Canada, surveys have been distributed to customers to gather this information, which is then presented to regulators for approval and used by utilities to support investment decisions. NS Power supports this approach and is prepared to integrate these factors into the company's existing risk framework to prioritize investments. As directed by the Board, NS Power will study and report on the potential use of VoLL in the reliability investment planning process in the 2026 ACE Plan application.

1.3 Looking Forward

While this Plan is built on sound projections and data and aims to provide the Board and stakeholders with specific actions and related timing and quantification of the improvement to reliability and resilience, there are factors beyond NS Power's control that can impact the Company's ability to achieve the specific actions in this Plan. As a result, the Plan must be adaptable and flexible and be regularly reassessed as required to maintain alignment with changing conditions. All changes will be assessed based on NS Power's asset management framework.

The issue of weighing the cost of improving the resilience of the system as compared to the benefits was recently addressed by the Board in its 2022 Annual Capital Expenditure Plan Distribution Routine D008 ATO decision:⁴

This highlights the need for open and frank dialogue between NS Power, its customers, and government about the level of performance that is desired and how much ratepayers are willing to pay for it. This is not to suggest that investments in resilient systems cannot be cost effective. But rate impacts must also be considered. A significant investment in system resiliency may cause immediate rate increases, whereas a business-as-usual option that may cost more in the longer term could result in more gradual, even if ultimately higher, rate increases.

Additionally, no system can be built to withstand every possible threat. This is an unrealistic expectation. Resilience should be understood more as a question of degree. Investments in resiliency will not necessarily eliminate damage from

⁴ M11169, NSUARB Decision, Nova Scotia Power 2022 ACE Plan Distribution Routines D0008 ATO, June 27, 2024, at paras. 39-40.

1 disruptive events but could help to reduce damage and could also facilitate the
2 recovery from a disrupted state to normal operations..⁵
3

4 These comments from the Board highlight what is an essential part of reliability and resiliency
5 investment decisions. Balancing the benefits from these investment decisions with rate impacts is
6 a complex challenge that requires careful consideration of both immediate and long-term
7 implications. As noted by the Board, these decisions and the weighing of the costs and benefits
8 require open and constructive dialogue among NS Power, its customers, and government to better
9 align the desired level of system performance and the associated costs.
10

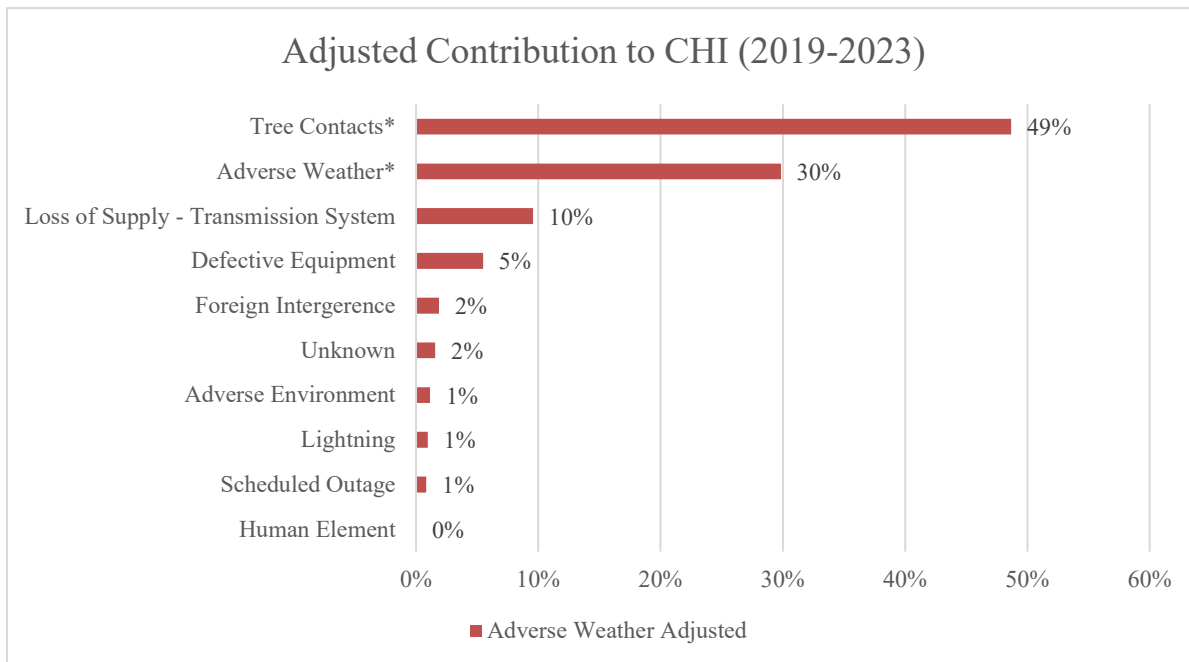
11 With this in mind, it is NS Power's hope that this Plan and the regulatory process related to it will
12 help facilitate such dialogue and assist in making investment decisions that meet the needs of Nova
13 Scotians today and in the future by providing an informed and appropriate balance between desired
14 performance and costs.

⁵ Mentioned first in Board's decision on M11169 (NS Power 2022 ACE Plan Distribution Routines D008 ATO, June 27, 2024 and then restated in M11458, NSUARB Decision, Nova Scotia Power 2024 ACE Plan, August 13, 2024 at para. 94.

2.0 HISTORICAL SYSTEM-WIDE RELIABILITY PERFORMANCE

Over the past five years, the causes of power outages and how they contributed to the customer hours of interruption (CHI) are shown in **Figure 2**. While there is year-over-year variation, NS Power’s operations and vegetation management subject matter experts estimate that up to 40 percent of CHI coded as “Adverse Weather” can be further attributed to tree contacts. Consequently, approximately 50 percent of the total CHI over the past five years has been due to trees contacting power lines, particularly during adverse weather events. Given this has been the top contributor to the hours of power interruption experienced by customers, ensuring the Plan and its investments appropriately address this factor is key to reducing SAIDI and SAIFI over the next five years.

Figure 2: Contribution to CHI by Outage Cause 2019-2023 (Including all Storms)



*These cause codes have been adjusted from the original Electricity Canada methodology as discussed above to illustrate the additional contribution from tree contacts within Adverse Weather.

As detailed in the next section, this Plan has been developed to align with this analysis and allocate planned investment appropriately to target and address the impacts of tree contacts and adverse weather on the power system.

1 **3.0 RELIABILITY PROGRAMS**

2
3 Nova Scotia Power's Five-Year Reliability Plan includes three key reliability programs that
4 address tree contacts and adverse weather (the primary causes of outages as outlined in the
5 previous section), as well as the other causes of unplanned outages:

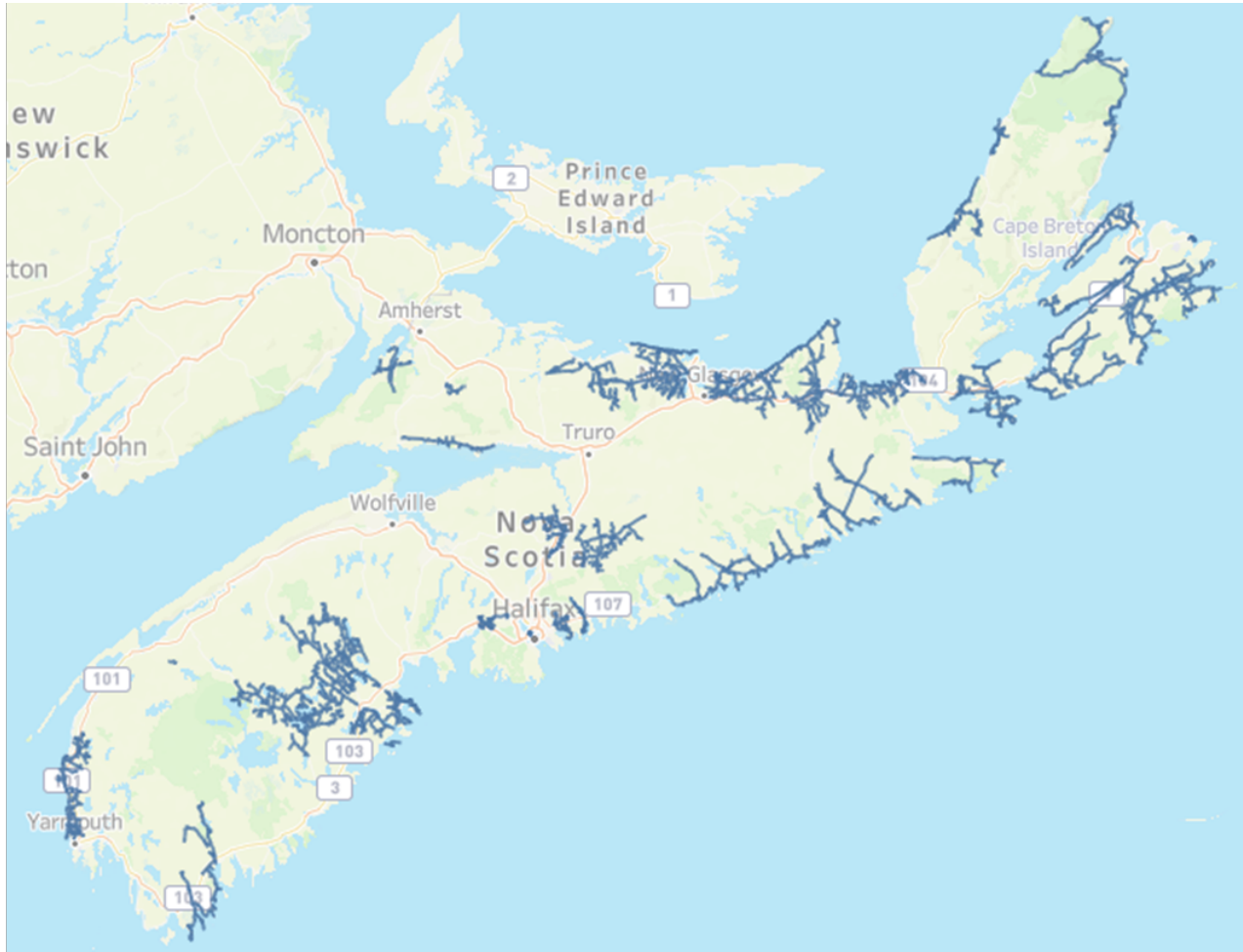
- 6
- 7 • **Storm Hardening - Vegetation Management:** This program includes investment to
8 widen existing rights-of-way serving both the transmission and distribution systems,
9 establish new rights-of-way where required, and trim and remove trees to increase the
10 clearance from power lines. Reducing tree contacts is the number one way to prevent
11 outages and reduce the overall duration when they do occur. This program is critical to
12 minimizing tree contacts with power lines, which are often impacted during weather
13 events.
14
 - 15 • **Storm Hardening - Targeted Equipment Replacements and Upgrades:** This program
16 includes investment to upgrade, modernize, or renew existing equipment and infrastructure
17 through targeted replacement and additional assets to improve resiliency.
18
 - 19 • **Advanced Grid Modernization:** This program focuses on addressing evolving demands,
20 aging infrastructure, and growing integration of renewable energy sources. The Company
21 deploys Grid Modernization investments across many foundational areas including
22 enhancing connectivity to the transmission and distribution grid to reduce occurrence and
23 length of outages and exploring advanced technology in vegetation management. These
24 investments target advanced technologies such as smart meters, enhanced communication
25 systems, upgraded substations, and self-healing devices to improve system reliability and
26 efficiency.
27

28 The priority areas across the province for investments in these programs are determined through
29 NS Power's asset management framework. As part of that framework, historical reliability

1 performance is one of the variables that determines the overall reliability risk and guides where
2 investments need to be prioritized.

3
4 At the time of filing of this Five-Year Reliability Plan, the priority areas for investment in 2025
5 include the following feeders shown below in **Figure 3**.

Figure 3: Highest Priority Distribution Feeders in 2025



Western Region	Metro Region	Northeast Region	Cape Breton Region
14V-303 70W-311 80W-301 16W-301 70W-313 91W-411 23W-302 73W-411 93V-313 25W-301 76V-301 57W-401 78W-301 57W-402 78W-302	137H-412 104H-421 82V-402 113H-433 126H-311	100C-421 30N-412 4C-441 4N-313 57C-426 82V-401 88H-401 50N-410 56N-414 6N-302 96H-411 96H-412 24C-442 4C-430 37N-411	57S-401 57S-402 11S-411 3S-403 59C-402 103C-314 22C-403 22C-404 81S-305 85S-401 58C-403

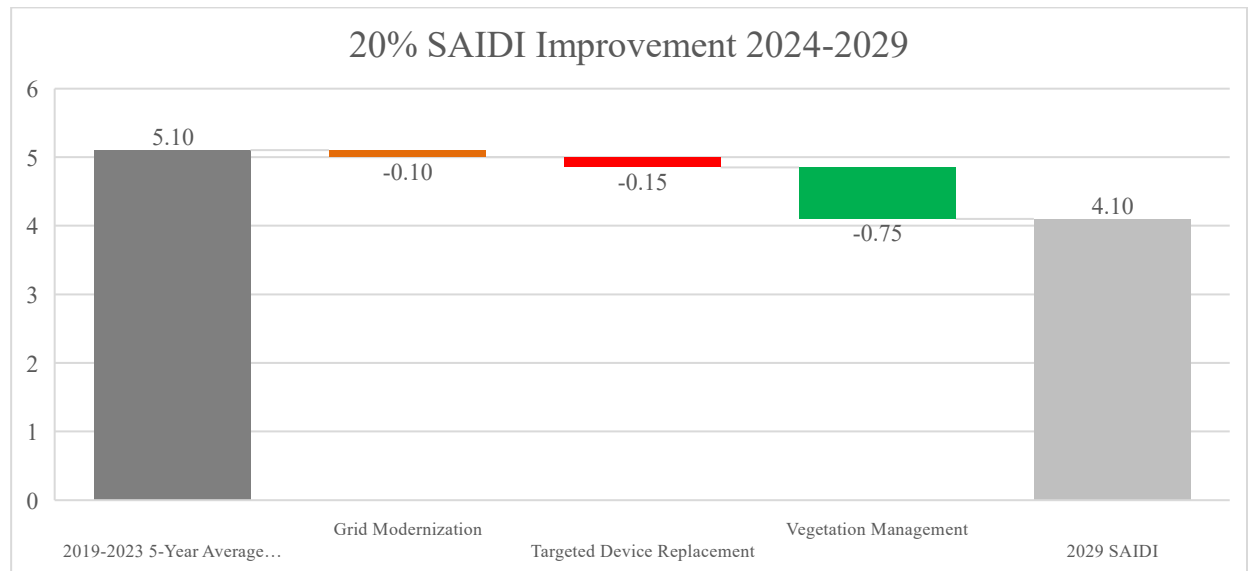
The feeders in **Figure 3** represent approximately 10 percent of NS Power’s distribution feeders across the province. While these are the primary areas of focus in 2025, NS Power will continue to reassess these priorities on an ongoing basis over the course of 2025 and this Plan. NS Power will also continue to respond appropriately to new areas of priority as they emerge.

The reliability improvements that NS Power estimates from these investments over the course of this Plan are outlined in the following section.

3.1 Estimated Improvements in Reliability

NS Power estimates that the programs included in this Plan will deliver an improvement in Performance Standards SAIDI of approximately 20 percent and achievement of the SAIDI metric included in the Standards by 2029. The projected impact of the three reliability programs is illustrated in **Figure 4** below which highlights the anticipated trajectory of Performance Standards SAIDI performance as these programs are executed. This 20 percent reduction in Performance Standards SAIDI equates to a one-hour reduction in outage duration over the course of one year by 2029. These investments will also enhance the functionality of the distribution system, enabling it to efficiently manage and support new load.

Figure 4: The Path to Improving SAIDI by 20 Percent



Every outage event has a resultant impact on the frequency of outages and the overall duration of outages. Consequently, and based on historical correlations between SAIDI and SAIFI performance, NS Power estimates that the Performance Standards SAIFI metric will also improve

1 by approximately 16 percent and will be below the current performance standard target of 2.05 by
2 2029. Every mitigating measure that avoids or reduces the impact of an outage has a related
3 benefit/reduction to the overall frequency and duration of outages experienced by customers.

4
5 SAIDI and SAIFI are often positively correlated because an increase in the frequency of outages
6 (SAIFI) typically leads to an increase in the total duration of outages (SAIDI). Both metrics are
7 influenced by weather conditions, design of the power system and the operational realities of how
8 reliability investments and outage management practices impact SAIDI and SAIFI. Investments
9 that are made to improve reliability and resilience (e.g. automated reclosers that detect transient
10 faults like tree contacts on a line and automatically restore power without the need for manual
11 intervention) simultaneously reduce the frequency of outages (SAIFI) and their duration (SAIDI).
12 The correlation factor between NS Power's SAIDI and SAIFI metrics over the past 20 years is 79
13 percent, meaning that there is a very strong relationship between these two variables and that
14 reduction in one of these metrics (SAIDI) going forward is highly likely to result in a similar level
15 of reduction in the other metric (SAIFI).

4.0 STORM HARDENING – VEGETATION MANAGEMENT

2025-2029 Forecast Investment: \$265.0 million

Estimated Performance Standards SAIDI Reduction: 0.70 to 1.25 hours

The Storm Hardening - Vegetation Management Program is designed to proactively reduce tree contacts with power lines, which is the primary cause of outages under normal, moderate and severe weather conditions. By increasing the width of distribution and transmission corridors and executing proactive vegetation control strategies, the program aims to reduce power interruptions and improve system reliability in the following ways:

- Greater access for crews conducting routine maintenance and/or post-storm repairs,
- Clear rights-of-way allow for easier visual and drone inspections, helping identify risks before they cause outages,
- Preventing contact with trees that have experienced ice accumulation causing them to bend or break onto conductors or equipment,
- Fewer power line conductor failures,
- Fewer equipment failures from the forces created when trees land on power lines, and
- Faster restoration overall.

The program includes the following targeted strategies, explained further below:

- Distribution Corridor Widening with Managed Rights-of-Way,
- Transmission Corridor Widening with Managed Rights-of-Way,
- Establishing New Rights-of-Way (ROW), and
- Trimming and removal of trees around existing power lines.

As outlined in M11921 New Distribution Rights-of-Way Phase 10,⁶ NS Power uses its Asset Management Mechanism and Feeder Risk Profiles to prioritize tree cutting. For distribution feeders, the criticality assessment considers factors such as electricity usage (kWh), regulatory consequences, customer count, redundancy, and ease of access. The condition score incorporates performance results, vegetation condition, load conditions, and feeder inspection data.

The condition rating of 1 to 5 indicates the overall vegetative condition of a feeder, with 1 meaning low vegetation proximity to the conductor (power line) and 5 indicating close proximity. NS Power assigns a condition rating for each section of the power line based on inspection data and work order history. This condition rating, combined with the criticality rating, determines which sections are targeted as priorities for vegetation management work to be completed.

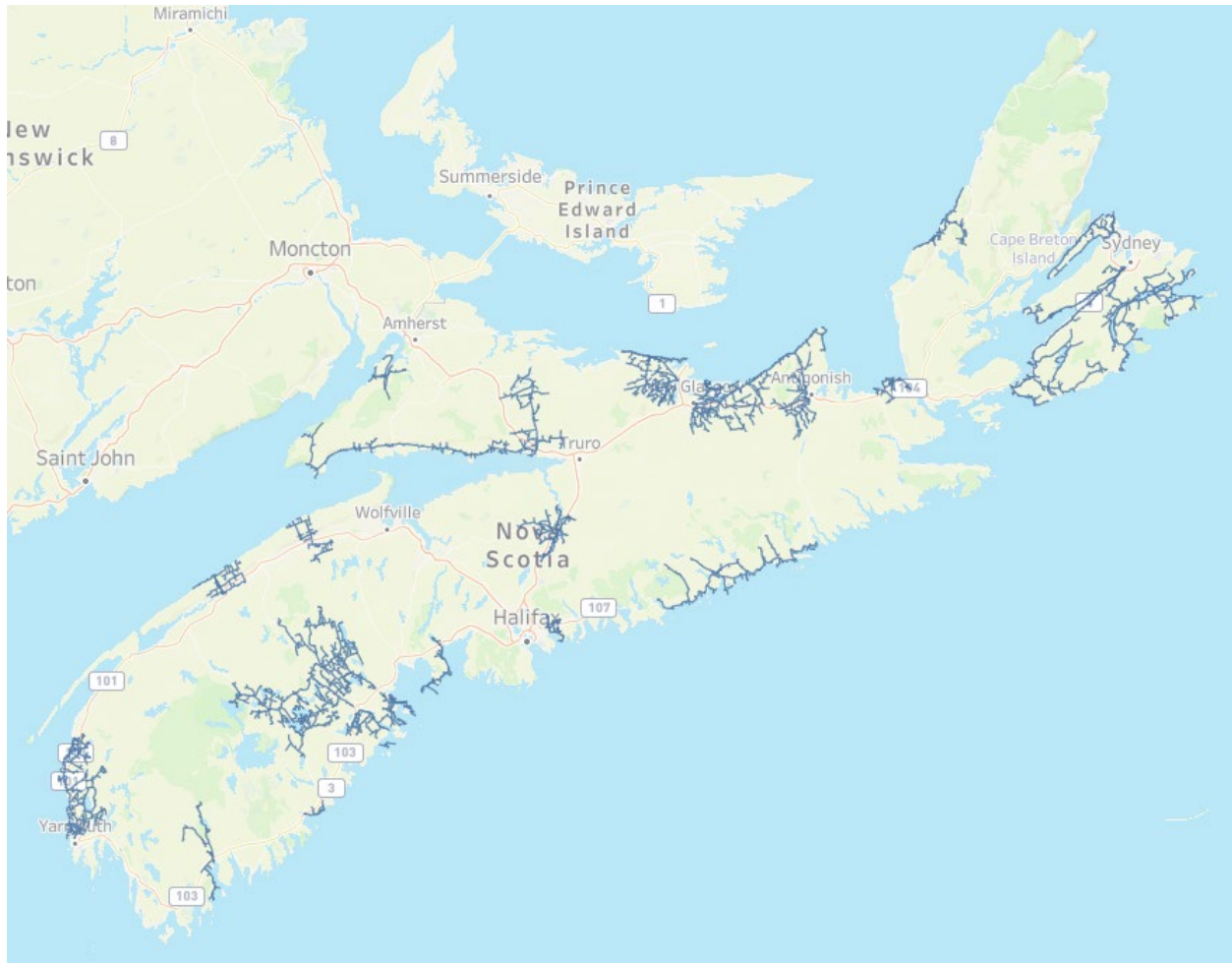
4.1 Distribution Corridor Widening with Managed Rights-of-Way (ROW)

2025-2029 Forecast Investment: \$66 million

This program will expand the width of distribution corridors that currently have a managed right-of-way to reduce tree encroachment risks and enhance clearance standards. Over the course of this Five-Year Plan, NS Power is currently forecasting a total investment of \$66 million in distribution right-of-way widening. In 2025, it is anticipated that NS Power will complete approximately 315 km of work and prioritize widening of the rights-of-way in approximately 40 communities. Vegetation management work is prioritized by analyzing historical outage data related to tree contacts and adverse weather, focusing on feeders or areas with the poorest performance. Previous vegetation cutting schedules are also reviewed to determine if additional maintenance is required, ensuring that high-risk feeders are addressed effectively. **Figure 5** shows the feeders planned for distribution widening in existing rights-of-way.

⁶ M11921, NSPI Responses to NSUARB Information Requests, New Distribution Rights-of-Way Phase 10, pages 9-10.

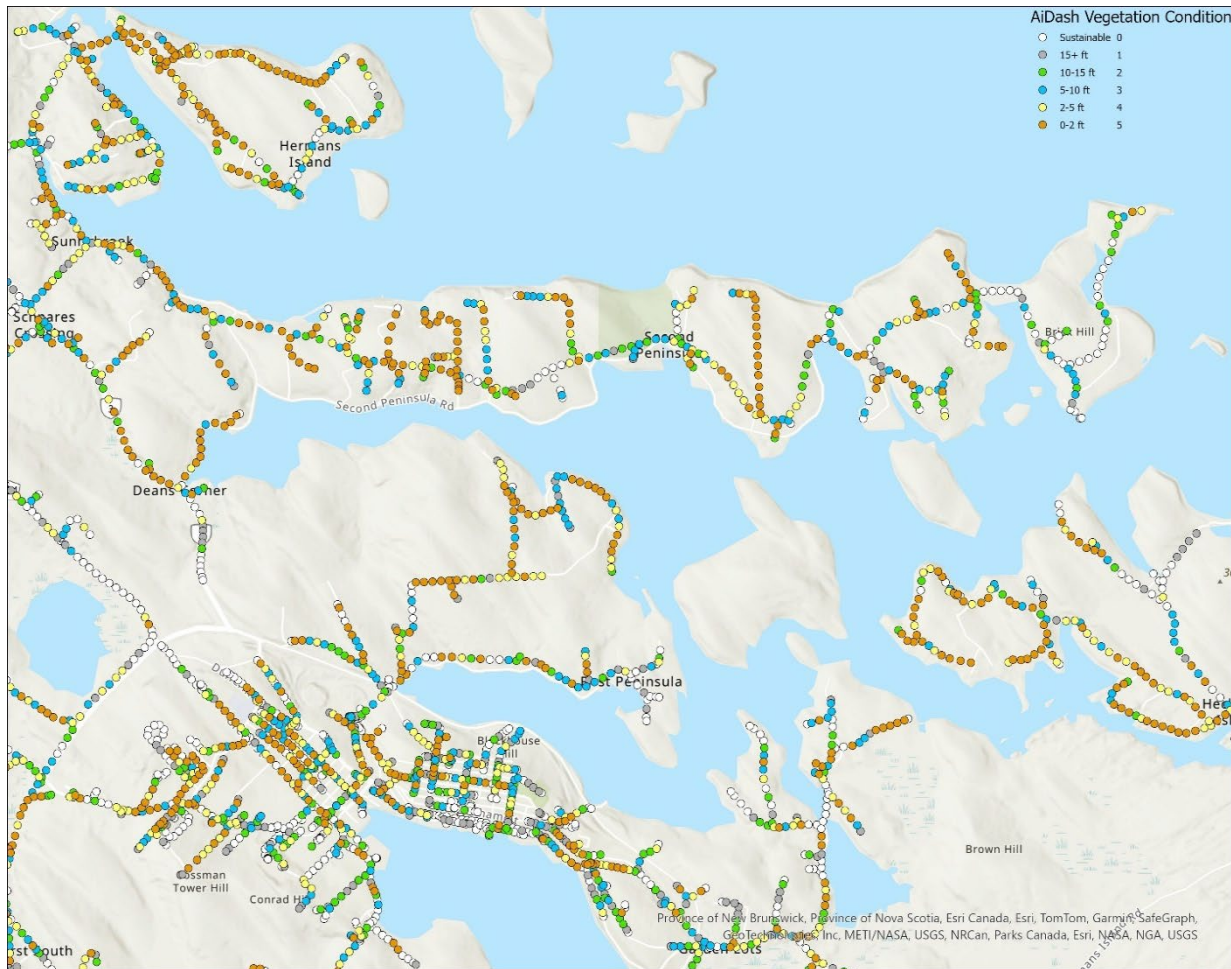
Figure 5: Distribution Vegetation Management Right of Way Widening (2025)



In 2025, NS Power will begin leveraging satellite imagery to further assess vegetation conditions by analyzing the proximity of vegetation to conductors. By combining this data with historical outage information, NS Power will enhance its ability to pinpoint vegetation problem areas within poorly performing circuits, enabling more targeted and precise vegetation management. As this technology is deployed, the evolving data and insights will continuously inform and help refine the workplan, ensuring resources remain focused on areas of highest risk and worst historical performance.

Figure 6 shows the satellite scan of vegetation along a section of priority feeder 78W-302. This scan highlights where vegetation is in close proximity to the conductors, providing a baseline to prioritize targeted vegetation management work on this feeder.

Figure 6: Vegetation Condition on 78W-302 from Satellite Imagery



4.2 Transmission Corridor Widening with Managed Rights of Way (ROW)

2025-2029 Forecast Investment: \$15 million

Similar to the distribution program, this program focuses on transmission lines and widening corridors with existing managed ROWs to improve reliability for critical transmission assets. As

outlined in the 2025 ACE Plan, NS Power is planning to invest \$3.0 million in 2025 to widen transmission rights-of-way. Over the course of this Plan, NS Power is currently forecasting a total investment of \$15 million in transmission right-of-way widening. In 2025, transmission widening is anticipated to take place in six transmission corridors in the following areas:

Figure 7: Transmission Corridors Targeted for Widening (2025)



Transmission	Geographic location of the Line
L-6511	Between New Glasgow and Glen Dhu
L-7003	Between Onslow and Port Hastings
L-7004	Between Dalhousie Mountain and Port Hastings
L-7005	Between Onslow and Port Hastings
L-7008	Between Brushy Hill and Bridgewater
L-7009	Between Brushy Hill and Bridgewater

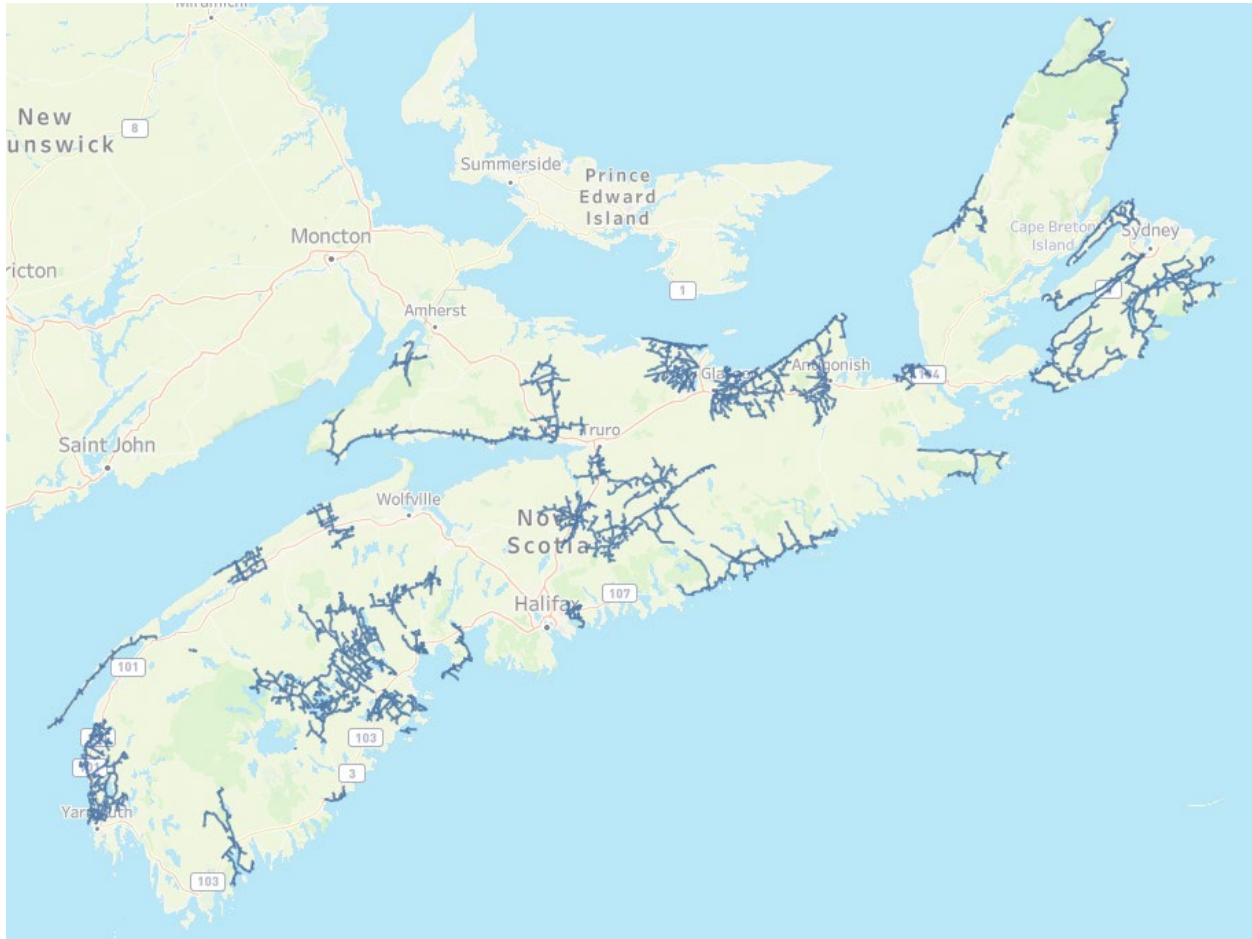
1 Right-of-way widening in these areas will continue to improve the transmission system’s ability
2 to withstand significant weather events where trees falling within the ROW can pose a risk to NS
3 Power’s infrastructure. Widening these ROWs mitigates the tree fall-in risk for the vast majority
4 of trees on the edge of the ROW.

5
6 **4.3 Establish New Rights-of-Way (ROW)**

7
8 **2025-2029 Forecast Investment:** \$86 million

9
10 This program establishes new ROWs for distribution feeders where rights-of-way have not
11 previously existed. NS Power targets feeders where traditional vegetation management practices
12 (e.g. trimming and removing trees) have a limited impact on preventing tree contacts that result
13 from trees outside the right-of-way falling into the power lines. As part of this program, NS Power
14 aims to establish rights-of-way with 20 feet of clearance from the conductor.

Figure 8: New Rights-of-Way for Distribution Feeders



4.4 Trimming and Removal of Trees Around Existing Power Lines

2025-2029 Forecast Investment: \$98 million

Trimming and/or removal of trees from around existing power lines is included under this portion of the Storm Hardening – Vegetation Management program. The work completed to trim and remove trees is aligned with the vegetation condition. The growth cycles also inform how the work is prioritized. The program is focused on areas that cannot be widened, such as in many urban areas that have tree canopies. As much as possible, work is scheduled such that the trees are cut back prior to reaching conductor height. The work plans for trimming and removal of trees will also be further enhanced by the addition of intelligence from satellite imagery. The satellite

1 imagery data is being integrated into the work planning and prioritization process for 2025, and
2 NS Power’s current plan is to trim and remove trees on approximately 3,200 spans (177 km) of
3 existing power lines in 2025.

5.0 STORM HARDENING – TARGETED EQUIPMENT REPLACEMENTS AND UPGRADES

2024-2029 Forecast Investment: \$916 million

Forecasted Performance Standards SAIDI Reduction: 0.13 to 0.24 hours

NS Power’s Storm Hardening - Targeted Equipment Replacements and Upgrades Program is designed to strengthen the power system and enhance its ability to provide reliable service across a range of operating conditions, including periods of adverse weather. By focusing on the highest-risk assets and areas, this program implements targeted measures to improve resilience, reduce unplanned outages, and ensure the system can adapt to evolving challenges (e.g. worsening weather conditions). This program includes the following areas of focus, further detailed below:

- Distribution System Equipment Upgrades and Replacements,
- Transmission System Upgrades and Replacements, and
- Substation Upgrades and Replacements.

5.1 Distribution System Equipment Upgrades and Replacements

2024-2029 Forecast Investment: \$487 million

This program is focused on modernizing and enhancing NS Power’s distribution system to improve reliability and resilience, meet growing demand, and ensure compliance with evolving regulations. Key initiatives include replacing aging infrastructure (e.g. hydraulic reclosers, conductors, step-down transformers), relocating equipment and infrastructure (e.g. relocating lines to roadside locations for better accessibility), and installing advanced protective devices like reclosers and trip savers to minimize outages. Investments under this program also include upgrades to underground infrastructure, upgrading equipment to support load growth in high-demand areas, and ensuring compliance with environmental regulations.

In 2025, \$9.2 million is planned to be invested to modernize and replace aging or obsolete equipment such as hydraulic reclosers, older devices that contain PCBs and step-down transformers. These multi-year programs are designed to improve reliability and ensure environmental compliance is maintained. NS Power plans to replace 39 devices identified as containing or potentially containing PCBs, including 16 step-down transformers, 18 downline primary metering tanks, and 5 voltage regulators. In addition, over 600 pole-top transformers will be replaced. Approximately 400 of these pole-top transformers are being replaced to address environmental and reliability priorities, and approximately 200 are being replaced solely to address the environmental risk associated with the concentration of PCB in those transformers.

The 2025 Distribution System Equipment Upgrades and Replacements program also includes the installation of new protective devices, such as reclosers and trip savers, to enhance the reliability of the grid. Reclosers automatically detect and respond to faults, isolating affected areas and minimizing the number of customers impacted by outages. These devices also reduce outage durations and improve restoration times, helping to prevent cascading outages and enhance overall grid resilience. The reclosers to be installed in 2025 are included in **Figure 9** below:

Figure 9: 2025 Recloser Installations

Region	Feeder	Communities Impacted
Northeast	24C-442	Canso and surrounding area
Northeast	50N-410	Merigomish and surrounding area
Cape Breton	22C-404	Isle Madam
Cape Breton	81S-303	Glace Bay, Port Morien
Metro	127H-411	Waverley and Fall River
West	55V-314	Berwick, Aylesford and Burlington
West	55V-314	Berwick, Aylesford and Burlington

In 2025, NS Power anticipates installing 16 trip saver devices across the province. Trip savers are protective devices installed on smaller sections of the distribution system where fuses would traditionally be used. Similarly to reclosers, trip savers quickly detect and isolate faults, allowing for the restoration of power to unaffected areas while minimizing the duration of outages.

Figure 10 includes the trip savers anticipated to be installed in 2025. Fourteen of the trip savers will be installed on the highest priority feeders.

Figure 10: 2025 Trip Saver Installations

Feeder	Trip Savers Installed
56N-414	1
81S-301	1
6N-301	1
57W-401	2
78W-301	1
57S-401	1
85S-401	1
4N-313	1
70W-311	1
113H-433	1
80W-301	1
91W-411	4

By targeting these locations, the trip-saver program will improve fault isolation and restoration efforts in key areas, ensuring a more stable and reliable power supply for customers. These installations, along with replacements of aging or damaged infrastructure, are part of NS Power's commitment to preparing the grid for future challenges and evolving customer needs.

To meet the growing number of customers and the evolving demands on the distribution system, NS Power is adding new equipment and infrastructure in areas experiencing or anticipated to experience significant growth. These projects address capacity challenges, while also ensuring reliable service for expanding communities.

Two key projects are planned for 2025 to create new distribution feeders:

- Prospect Road, Halifax: A 2.7 km, three-phase line will be constructed to serve the communities along Prospect Road. This project includes the installation of approximately

54 poles and 10.8 kilometers of primary and neutral conductor, enhancing capacity and reliability in this rapidly expanding area.

- 99H Substation, Dartmouth: A new feeder is anticipated to be commissioned from the 99H substation in the North End of Dartmouth to address significant growth in Shannon Park, Wyse Road, and Downtown Dartmouth. This development will alleviate capacity constraints on existing feeders and support the increasing demand in these areas.

These projects are instrumental in accommodating increasing load while maintaining the reliability and efficiency of the distribution network.

As part of NS Power's Plan to improve reliability and resilience, NS Power is updating some of its overhead distribution design standards to align with the latest CSA C22.3 overhead line standards. These updates include specifying larger class poles, resulting in stronger installations in many cases. Advanced pole modeling software is being used to study the effects of wind, ice, equipment, and attachment loads on pole integrity. The analysis completed with this modeling software provides a more accurate assessment of how poles respond to external forces (e.g. high-speed wind gusts), ensuring poles that are capable of withstanding heavy weather and extreme wind conditions and specified and installed.

In addition, NS Power has developed coastal framing standards to storm-harden new and existing power lines in harsh coastal environments. These standards include stronger insulators designed to withstand greater wind loading and utilize clamp-style attachments for a more secure hold compared to conventional tie wire. Together, these enhancements improve the resilience of the distribution system against severe weather conditions.

The following three subprograms are part of the overall Distribution System Equipment Upgrades and Replacements program.

5.1.1 Distribution System Build-to-Roadside Program

2025-2029 Forecast Investment: \$12 million

The purpose of this program is to bring distribution lines closer to the roadside (re-routing them from off-road areas where they are not easily accessible). Relocating infrastructure to roadside reduces the likelihood of tree contacts, since the roadways are clear, and allows the associated equipment to be inspected and assessed more easily. Additionally, Power Line Technicians (PLTs) can patrol and access the distribution feeders more quickly in the event of an outage and thus restore power more effectively.

In 2025, it is anticipated that approximately eight kilometers of distribution line will be re-built closer to the roadside. Details of the projects anticipated to be completed in 2025 can be found in **Figure 11** below.

Figure 11: 2025 Bring-to-Roadside Projects

Feeder	Project Name	Description
100C-421	Havre Boucher Rebuild	Bringing 1.4 km of three phase line from cross-country to roadside.
85S-401	Parks Canada Halfway Brook to Neils Harbour	Bringing 0.75 km of line to roadside, with the new road and bridge being built by Parks Canada.
103C-314	Chéticamp Back Road Bring to Roadside	Bringing approximately 1.0 km of three-phase line along the Cabot Trail at the Grand Étang River to roadside.
512W-311	Lake Torment Rebuild	Upgrading 7.5 km of 12 kV line to 25 kV, including bringing 0.5 km of conductor to roadside.
126H-312	Lawrencetown Route 207 Realignment	Bringing approximately 1.0 km of line to roadside on Route 207 in Lawrencetown.
131H-422	Etter Road Rebuild	Bringing approximately 1.0 km of primary and neutral conductor to roadside on Etter Road in Mount Uniacke.
19C-204	Durrells Island Conversion	Bringing 1.6 km of primary and neutral conductor to roadside on Durrells Island.
33N-201	Canaan Road Conversion	Bringing 1.3 km of primary and neutral conductor to roadside between New Canaan and Halfway River East.

5.1.2 Distribution System Conductor Upgrades

2025-2029 Forecast Investment: \$26 million

The Distribution Conductor Upgrades program focuses on the proactive replacement and modernization of aging infrastructure to reduce the risk of outages and improve reliability and resilience of the distribution system.

In 2025, it is anticipated that approximately 39 kilometers of distribution line will be reconductored. **Figure 12** outlines the feeders that will have portions of the existing conductors replaced or upgraded along with how many kilometers are estimated to be completed.

Figure 12: 2025 Conductor Upgrades by Region

Region	Feeders to be Reconductored	km Reconductored
Cape Breton	2	5.4
West	5	9.7
Metro	18	10.6
Northeast	7	12.8

5.1.3 Distribution System Underground Upgrades

2024-2029 Forecast Investment: \$37 million

Another focus area of the Distribution System Equipment Upgrades and Replacements Program is distribution underground upgrades, supported by \$6.2 million investment in 2025. This includes targeted replacements of underground devices, pad-mount transformers and switches, as well as vault and manhole upgrades to address aging infrastructure and enhance resilience. In 2025, work

1 will begin on the replacement of approximately 800 meters of primary underground cable on 1H-
2 403 in downtown Halifax that has been identified as being at risk of failure due to condition.
3 Additionally, the underground upgrades program includes replacement of approximately 50 pad-
4 mount transformers.

5 6 **5.2 Transmission System Upgrades and Replacements**

7
8 **2025-2029 Forecast Investment:** \$196 million
9

10 In 2025, a targeted transmission investment of \$33 million will fund a range of initiatives aimed
11 at improving reliability and making the transmission system more resilient. These initiatives
12 include over \$14.7 million for traditional replacements and upgrades to reinforce core
13 infrastructure (transmission structures and conductors, for example), along with more than \$3.6
14 million dedicated to unique, site-specific projects, including water crossing upgrades, line
15 realignments and targeted line rebuilds. Additionally, \$4.8 million is allocated to key programs
16 aimed at ongoing maintenance and asset life extension programs, including wood pole retreatment,
17 steel tower refurbishment and removal of older lines from service that are being retired. More
18 details on these transmission system investments are included in the 2025 ACE Plan.
19

20 **5.3 Substation Upgrades and Replacements**

21
22 **2025-2029 Forecast Investment:** \$233 million
23

24 This program supports a range of initiatives to replace existing substation assets such as
25 transformers, breakers and switches. Additionally, \$12 million is designated to construct new
26 substations, or expand/rebuild existing substations.
27

28 In 2025, it is anticipated that four substation transformers will be replaced serving the communities
29 and surrounding areas of Nictaux, Springhill, Mahone Bay, and Dartmouth. At the Middlefield
30 substation, enhanced protection and sectionalizing capabilities are being added to improve

1 reliability by enabling the ability to isolate faults to a specific area, reducing outage impacts and
2 enabling faster restoration.

3
4 Additionally, the purchase of a spare substation transformer is necessary to provide additional
5 coverage for several units across the province which are showing signs of deterioration. The spare
6 transformer will provide backup for a number of contingency scenarios involving these targeted
7 units.

8
9 This investment also includes three new substations in Bridgewater, Stellarton, and Susie Lake, as
10 well as the continuation of construction on the new Mount Uniacke substation. The addition of
11 these four substations will enhance system capacity and reliability in these growing communities.
12 These investments will support increased demand, improve operational flexibility, and strengthen
13 the overall resilience of the electrical grid.

6.0 ADVANCED GRID MODERNIZATION PROGRAMS

2025-2029 Forecast Investment: \$78 million

Forecasted Performance Standards SAIDI Reduction: 0.06 to 0.11 hours

In addition to the grid modernization that is becoming inherent in some of the traditional equipment upgrades described above in section 5.0, the integration of additional real-time monitoring and automation will enable NS Power to better detect and address issues on the power grid more quickly. For example, smart grid technologies can help pinpoint causes of power outages with greater precision and improve recovery times during power outages by reducing the time spent locating a fault and allowing for a more efficient dispatch of resources. Additionally, enhanced visibility and control over Distributed Energy Resources (DERs) allows utilities to better balance supply and demand, manage fluctuating grid conditions, and integrate intermittent renewables improving stability and power quality. These improvements will ultimately reduce the frequency and duration of outages, ensuring that customers experience a more reliable and consistent energy supply.

The following two subprograms, (6.1) Connected Assets and (6.2) Fault Isolation and Service Restoration, are part of the overall Advanced Grid Modernization program.

6.1 Connected Assets

2025-2029 Forecast Investment: \$65 million

NS Power is expanding the implementation of telecommunications connectivity providing telemetry and controls to intelligent field devices throughout the grid, including Remote Terminal Units (RTU) and communications to distributed protection equipment. This allows for improved awareness of outages, expedited knowledge of fault locations and remote operation capabilities as well as enhanced data allowing for more in-depth asset management activities. Currently, it is widely recognized that the deployment of Supervisory Control and Data Acquisition (SCADA)

connectivity to the grid will help enable Grid Modernization and correspondingly, this will be a key area of investment.

6.1.1 Remote Terminal Units (RTUs)

2025-2029 Forecast Investment: \$ 21 million

Throughout 2024-2029, NS Power intends to deploy up to 58 additional RTUs to substation sites in a combination of existing device replacements or upgrades as well as new deployments. In 2025, RTU projects will focus on the following areas:

Figure 13: Remote Terminal Units Proposed for 2025

RTU		
Region	Area / Community	Substation
Cape Breton	Port Hastings	2C
Cape Breton	Southwest Margaree	58C
Cape Breton	Cleveland	22C
Northeast	Tatamagouche	4N
West	Hebron	16W
West	Bridgewater East	89W
West	Bridgetown Rural	70V
West	Kingston	63V
West	Ohio Road	25W
West	Central Argyle	19W
West	Wolfville Ridge	83V
West	Indian Path	80W

6.1.2 Downline Connectivity

2025-2029 Forecast Investment: \$44 million

Expanding on Section 6.1, adding a communications path from a downline recloser to the ADMS environment can provide reliability benefits including faster fault location during power outages, reduction of delays caused by driving distance between devices due to remote SCADA operation, and improved asset management data as well as safety benefits of reducing line-of-fire with remote operation.

Throughout 2025-2029, NS Power intends to deploy connectivity to downline reclosers. Proposed 2025 / 2026 projects include deployment of connectivity on up to 28 downline reclosers and the company is planning projects in subsequent years with intention to scale deployment based on learnings in field deployment and Control Center integration with previously executed projects. The 2025 / 2026 locations include deployments in the following areas:

Figure 14: Downline Reclosers Planned for 2025-2026

Downline Connectivity		
Region	Area / Community	Feeder / Substation (part of)
West	Three Mile Plains	79V-401
Metro	Musquodoboit Harbour	87H-313
		87H-313
Northeast	Dickie Brook	24C-442
Northeast	Ruth Falls	96H-412
		96H-412
		96H-412
West	Waterville	55V-313
Metro	Lucasville	131H-422
Cape Breton	Ingonish & Cape North	85S-401
Cape Breton	Coxheath & Eskasoni	11S-411
Metro	Lakeside	103H
Metro	Kearney Lake	129H
Metro	Hammonds Plains	137H
Metro	Armdale	2H
Metro	Kempt Rd	104H

1 In addition to these efforts, NS Power is investing in advanced technologies and system upgrades
2 to enhance the supporting systems that enable downline connectivity. These include modernizing
3 communication networks to ensure fast and reliable data transfer, upgrading system controls to
4 support more precise device coordination, and implementing advanced grid management software
5 for enhanced monitoring and decision-making.

6 7 **6.2 Fault Location Isolation and Service Restoration**

8 9 **2025-2029 Forecast Investment: \$13 million**

10
11 Fault Location, Isolation and Service Restoration (FLISR) is a system of distribution protection
12 devices sited to allow automatic and remote re-configuration of the distribution grid to improve
13 feeder reliability by reducing interruption impacts to the minimum number of customers possible.
14 Wide-ranging visibility and control of the distribution network is a foundational investment
15 towards grid modernization goals and enablement of communication and remote operation
16 capabilities can improve reliability metrics both during normal operations and when the
17 distribution system is highly stressed during storms and other major events. Industry case studies
18 and statistics show that investment in Centralized and De-centralized self-healing grid projects can
19 impact reliability by reducing Customer Interruptions (CI) and Customers Hours of Interruption
20 (CHI).

21
22 Building on the deployment of distributed connected assets, as discussed in Section 6.1, some of
23 these locations will contribute to future self-healing grid projects as the company aims to build on
24 successfully operationalized pilot projects that have demonstrated a 61 percent reduction in CHI
25 in the area covered by the deployed project.

26 27 **6.2.1 Distributed Energy Resources (DERs)**

28 As the country moves towards a net-zero future, and as Distributed Energy Resources (DER)
29 proliferates throughout energy grids, flexibility of the grid will become increasingly important.

1 Energy will often be generated and timed when weather patterns and customers decide, not when
2 the grid demands. The patterns on which utility customers consume electricity are changing,
3 requiring new methods and capabilities to manage the grid. Enhanced data and automation will
4 enable management capabilities. DER visibility and control will support mitigation of negative
5 grid impacts while unlocking new integrated value chain opportunities.

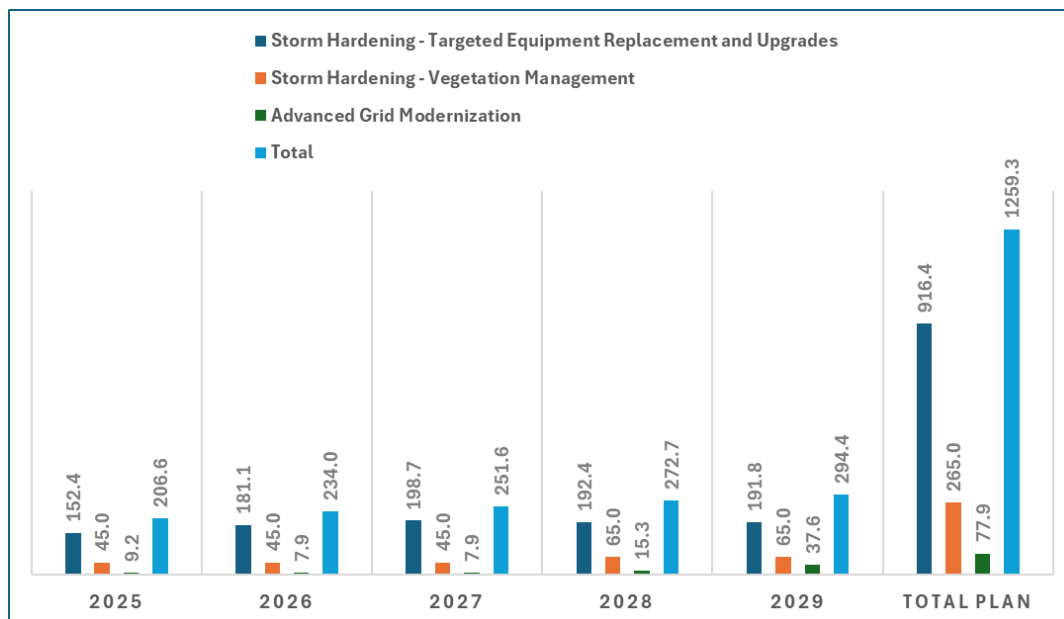
6
7 Following on the successes of the Intelligent Feeder and Smart Grid Nova Scotia projects, NS
8 Power is evaluating its approach to best integrate DER into the Nova Scotia grid, including
9 deployment of a DERMS platform with capabilities to manage DER within system constraints to
10 maintain system stability and reliability by orchestrating DER-related use cases, where control
11 capabilities exist.

7.0 CONCLUSION

This Plan demonstrates NS Power’s commitment to delivering reliable and resilient electrical service to customers. By investing in infrastructure hardening, grid modernization, vegetation management, and leveraging innovative technologies, the Company is addressing both immediate needs and long-term challenges to enhance system performance and recovery capabilities. While this plan aims to provide the Board and stakeholders with specific actions, related timing, and quantification of the improvement to reliability and resilience, evolving circumstances, some of which are beyond NS Power’s control, may impact NS Power’s ability to complete specific actions outlined in this Plan. As a result, the Plan must be flexible and will be reassessed routinely to update strategies to stay aligned with changing conditions.

NS Power commits to identifying all updates to this Plan in subsequent ACE Plans as directed by the Board in M11692. These updates will demonstrate the evolving nature of the Plan, reflecting any emerging risks, information about evolving weather patterns, stakeholder data and feedback, new opportunities for further collaboration, potential new technologies, and updated investment forecasts to the benchmark forecast included in this Plan and summarized in **Figure 15** below:

Figure 15: Benchmark Investment Forecast by Reliability Program (2025-2029):



1 NS Power is committed to proactively communicating progress on reliability improvements and
2 any adjustments to our strategies in a transparent manner. Moving forward, NS Power continues
3 to explore partnerships to advance significant resilience investments, including the potential for
4 capital-intensive projects like undergrounding.

5
6 As stated previously, it is NS Power’s hope that this Plan and the regulatory process related to it
7 will provide the opportunity to engage with stakeholders not only on the importance of making the
8 grid more reliable and resilient to the impacts of climate change, but also the appropriate balance
9 between desired performance and costs.

APPENDIX A – DEFINITIONS

DERs (Distributed Energy Resources):

Small-scale, decentralized power sources such as solar panels, wind turbines, and battery storage systems that are connected to the distribution grid.

DERMS (Distributed Energy Resource Management System):

Software platforms designed to integrate, monitor, and manage distributed energy resources to optimize grid performance and reliability.

Extreme Event Day (EED): A day when the daily cumulative hours of interruption exceeds the Extreme Event Threshold, calculated annually using the 3.5 beta method.

Feeder: A distribution circuit that delivers electricity from substations to end-use customers. Feeders often consist of overhead and underground lines, serving specific geographic areas.

Advanced Grid Modernization: Refers to the integration of advanced technologies, capabilities and data into utility systems and practices to enhance efficiency, customer experience, reliability, resilience and sustainability of the electrical grid. It encompasses upgrades to infrastructure, the adoption of digital tools, and the implementation of innovative operational strategies.

IEEE: Institute of Electrical and Electronics Engineers

Major Event Day (MED): As defined by the IEEE Standard 1366, is a day when the daily cumulative hours of interruption exceeds the Major Event Threshold, calculated annually using the 2.5 beta method.

Major Event: a significant weather-related or other disruptive event that results in at least one Major Event Day (MED).

Performance Standards SAIDI: Calculated in a similar manner to SAIDI, but excluding EEDs, MEDs and planned outages as detailed in the Board’s directive related to Performance Standards⁷.

Performance Standards SAIFI: Calculated in a similar manner to SAIFI, but excluding MEDs and SEDs.

Recloser: An automated electrical switch that can interrupt and reclose a circuit to isolate faults temporarily, allowing power restoration, often, without manual intervention.

Reliability: The ability of the electric grid to deliver uninterrupted power to customers under normal operating conditions.

Resilience: The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions.

SAIDI (System Average Interruption Duration Index): SAIDI is a measure of the duration of electric system outages. It is calculated by dividing the total duration of customer outages by the total number of customers served.

$$\text{SAIDI} = \frac{\text{The sum of the total customer hours of Interruption}}{\text{Total Customers served}}$$

SAIFI (System Average Interruption Frequency Index): SAIFI is a measure of the frequency of electric system outages. It is calculated by dividing the total number of customer interruptions by the total number of customers served.

$$\text{SAIFI} = \frac{\text{The sum of the total number of customers interrupted}}{\text{Total Customers served}}$$

⁷M10279 – Order, April 7, 2022 approving 2022-2026 Performance Standards Compliance Filing Attachment 2, section 1.0.

- 1 **Significant Event Day (SED):** A day when the daily cumulative hours of interruption exceed the
- 2 Significant Event Threshold. The Significant Event Threshold is calculated annually using the 2.0
- 3 beta method.

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1 **Request IR-21:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 4 Load Forecast**

4
5 **On page 24 of the application, NS Power notes that its forecast for net energy consumption**
6 **in the province over the two-year test period was produced in September of 2024 using an**
7 **updated version of the 2024 Load Forecast filed in April 2024, with the main differences**
8 **being assumptions to renewable to retail load, and updated economic and sales forecasts (up**
9 **to May 2024).**

10
11 **(a) Please provide a version of Figure 3 from the 2024 Load Forecast, on page 9 of 175 of**
12 **SR-02, Attachment 1 (Exhibit N-17), to reflect the updated forecast used for the 2026-**
13 **2027 GRA.**

14
15 **(b) Please explain why NS Power did not use or update its 2025 Load Forecast filed in**
16 **June 2025 (M12349) for the purposes of this 2026-2027 GRA proceeding.**

17
18 **(c) Please identify any differences between the GRA load forecast and the 2025 Load**
19 **Forecast and describe the reasons for these differences.**

20
21 **(d) Please compare the electric vehicle adoption rates assumed in the 2026-2027 GRA**
22 **forecast, and the 2025 Load Forecast, which adjusted adoption rates compared to the**
23 **2024 Load Forecast to align with recent trends and the elimination of federal and**
24 **provincial rebates.**

25
26 **(e) Please describe how the 2026 and 2027 forecasts were adjusted for increase behind**
27 **the meter solar uptake, in keeping with the 2025 forecast.**

28
29 **(f) Please confirm, correct and complete the data in the table below:**
30

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2026	Net System Requirement (GWh)	% Difference from GRA Forecast	Net System Peak (MW)	% Difference from GRA Forecast
2024 Load Forecast	11,306	-0.75%	2,428	
GRA Load Forecast	11,392	N/A		N/A
2025 Load Forecast	11,403	0.10%	2,408	
2027	Net System Requirement (GWh)	% Difference from GRA Forecast	Net System Peak (MW)	% Difference from GRA Forecast
2024 Load Forecast	11,347	0.32%	2,437	
GRA Load Forecast	11,311	N/A		N/A
2025 Load Forecast	11,193	-1.04%	2,423	

Response IR-21:

- (a) Please find a version of Figure 3 from the 2024 Load Forecast, modified to reflect the updated forecast used for the 2026-2027 GRA, below:

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2014	11,037	-1.4	2,118	4.2
2015	11,099	0.6	2,015	-4.9
2016	10,809	-2.6	2,111	4.8
2017	10,873	0.6	2,018	-4.4
2018	11,250	3.5	2,073	2.7
2019	11,077	-1.5	2,060	-0.6
2020	10,723	-3.2	2,050	-0.5
2021	10,902	1.7	1,968	-4.0
2022	11,134	2.1	2,216	12.6
2023	11,131	0.0	2,455	10.8
2024F	11,490	3.2	2,365	-3.7
2025F	11,552	0.5	2,398	1.4
2026F	11,378	-1.5	2,418	0.8
2027F	11,289	-0.8	2,429	0.5
2028F	11,347	0.5	2,458	1.2

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Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2029F	11,388	0.4	2,485	1.1
2030F	11,466	0.7	2,539	2.2
2031F	11,487	0.2	2,576	1.5
2032F	11,557	0.6	2,616	1.6
2033F	11,581	0.2	2,663	1.8
2034F	11,675	0.8	2,719	2.1

(b) Work for the 2026-2027 GRA proceeding began before the 2025 Load Forecast was finalized, so an updated version of the 2024 Load Forecast, with assumptions updated based on available data at the time work for the GRA proceeding began, was used. No further updates were made to the GRA Load Forecast once work for the GRA began, to ensure efficiency and minimize confusion in the regulatory process due to changes in assumptions. For further information, please refer to the Company's response to BW IR-7.

(c) A comparison of NSR and System Peak forecasts for 2026 and 2027 from the GRA Load Forecast and 2025 Load Forecast is given below:

Year	NSR (GWh)			System Peak (MW)		
	GRA Load Forecast	2025 Load Forecast	Change (%)	GRA Load Forecast	2025 Load Forecast	Change (%)
2026F	11,378	11,403	0.2	2,418	2,408	-0.4
2027F	11,289	11,193	-0.9	2,429	2,423	-0.2

The main differences between the forecasts are as follows:

- RTR impact: Compared to the 2025 Load Forecast, the GRA Load Forecast has higher RTR sales in 2026 (-300 GWh vs -144 GWh). This is due to updated forecasts provided by the Licensed Retail Supplier.
- EV forecast: Compared to the 2025 Load Forecast, The GRA Load Forecast has higher EV sales for 2026 and 2027. This is because EV sales were adjusted

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downwards for the 2025 Load Forecast due to the removal of federal and provincial incentives. Additionally, the energy impact was increased and the peak impact was reduced based on analysis of customer AMI data.

- Underlying economic forecasts and sales data: These were updated to the end of 2024 for the 2025 Load Forecast, while the GRA Load Forecast only had data up to May 2024, owing to data availability at time of forecast production.

- (d) A comparison of the EV adoption rates assumed in the 2026-2027 GRA Load Forecast and the 2025 Load Forecast is provided in the table below. Energy estimates increased in the 2025 Load Forecast as a result of analysis of AMI data:

Year	EV Sales			EV Energy (GWh)		
	GRA Load Forecast	2025 Load Forecast	Change (%)	GRA Load Forecast	2025 Load Forecast	Change (%)
2026F	3,975	2,442	-39	17	19	12
2027F	5,121	3,009	-41	24	20	-17

- (e) No adjustments were made to behind-the-meter solar uptake for the 2026 and 2027 GRA forecasts. Changes were made for the 2025 Load Forecast only. A comparison of new solar installs assumed in the 2026-2027 GRA Load Forecast and the 2025 Load Forecast is provided in the table below. While the number of installations is lower in the 2025 Load Forecast, there is a higher number of commercial installations which are larger on average, resulting in a larger reduction in energy.

Year	Solar Installations			Solar Energy (GWh)		
	GRA Load Forecast	2025 Load Forecast	Change (%)	GRA Load Forecast	2025 Load Forecast	Change (%)
2026F	3,342	3,085	-7.7	-37	-38	2.7
2027F	3,701	3,530	-4.6	-41	-44	7.3

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(f) The NSR and Net System Peak values from the 2024 and 2025 Load Forecast are confirmed. However, the NSR values given for the GRA Load Forecast are incorrect, as addressed in response to NSEB IR-023. This has been corrected in the completed table below.

2026	Net System Requirement (GWh)	% Difference from GRA Forecast	Net System Peak (MW)	% Difference from GRA Forecast
2024 Load Forecast	11,306	-0.75%	2,428	-0.41
GRA Load Forecast	11,378	N/A	2,418	N/A
2025 Load Forecast	11,403	0.10%	2,408	-0.41

2027	Net System Requirement (GWh)	% Difference from GRA Forecast	Net System Peak (MW)	% Difference from GRA Forecast
2024 Load Forecast	11,347	0.51%	2,437	0.33
GRA Load Forecast	11,289	N/A	2,429	N/A
2025 Load Forecast	11,193	-0.85%	2,423	-0.25

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Request IR-22:

Reference: Exhibit N-3 GRA Direct Evidence, Section 4 Load Forecast

On page 25 of the application, NS Power states “While migration to RTR [Renewable to Retail] reduces sales, it has no impact on forecast peak demand, which is expected to increase by 0.4 percent in 2026 and 1.2 percent in 2027.”

(a) Please explain why RTR has no impact on peak demand. Are 100% of RTR customers assumed to be on NS Power generated energy at system peak?

(b) Please explain the increased net system requirement due to a change in forecast RTR sales noted in the 2025 Load Forecast.

(c) Please describe how the 2026 and 2027 load forecasts were adjusted for the increased sales in the RTR market as provided in the 2025 Load Forecast.

(d) What are the reasons for those expected increases?

(e) What are the MW levels associated with those percentages?

Response IR-22:

(a) NS Power, as the system operator, is required to ensure adequate firm capacity is available to serve the peak in-province demand, including the demand of the RTR participants. The firm capacity contributions of the Licensed Retail Supplier’s generation assets are considered when determining the necessary firm capacity needed to meet forecast peak demand in the province. As such the RTR market’s impact at peak is considered on the supply side rather than the demand side.

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(b-c) The RTR energy assumptions for the 2024, 2024 GRA and 2025 load forecasts are provided in the following table:

Year	2024 Load Forecast RTR Impact (GWh)	2024 GRA Forecast RTR Impact (GWh)	2025 Load Forecast RTR Impact (GWh)
2026	-246	-300	-144
2027	-246	-421	-421

RTR sales have decreased by 102 GWh for 2026 and have increased by 175 GWh for 2027 between the 2024 and 2025 Load Forecasts, increasing net system requirement for 2026 and decreasing net system requirement for 2027 and beyond.

(d) Changes to the RTR assumptions are based on updated forecasts provided by the Licensed Retail Supplier.

(e) As explained in part (a), peak demand is forecast independently from RTR energy sales, so changes to RTR energy sales have no impact on the peak demand forecast.

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Request IR-23:

Reference: Exhibit N-3 GRA Direct Evidence, Section 4 Load Forecast.

On page 25, NS Power stated that compared to the 2024 Load Forecast, sales increased 86 GWh in 2026 and decreased 36 GWh in 2027. However, it also stated that the year over year change is forecast to be -1.4% in 2026 and -0.8% in 2027.

(a) Please reconcile the 86 GWh increase in 2026 against the 1.4% decrease in 2026.

(b) Please reconcile the 36 GWh decrease in 2027 against the 81 GWh decrease on page 24 (i.e., 11,392 GWh - 11,311 GWh).

Response IR-23:

(a-b) Figure 4-1 on page 24 of Exhibit N-3 Section 4 Load Forecast should be as follows:

Year	Anticipated Load (GWh)
2026	11,378
2027	11,289

The corresponding changes from the 2024 forecast should be 72GWh in 2026 and -28GWh in 2027. The 86 GWh increase represents the change between the 2024 Load Forecast report value for 2026.

The 1.4 percent decrease refers to change from 2025 to 2026 from the GRA forecast (11,536 GWh estimated in 2025 to 11,378 GWh in 2026). Likewise, the 0.8 percent decrease refers to the change from 2026 to 2027 from the GRA forecast (11,378 GWh to 11,289 GWh). In the filing, these were calculated from the correct forecast values.

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The values for the forecasts and corresponding variances are provided in the following tables for comparison.

Filed Values

Year	2024 Forecast Load (GWh)	GRA Forecast Load, Figure 4-1 (GWh)	Variance (GWh)
2026	11,306	11,392	86
2027	11,347	11,311	-36

Corrected Values

Year	2024 Forecast Load (GWh)	GRA Forecast Load, Corrected Figure 4-1 (GWh)	Variance (GWh)	Year Over Year Change (GRA Forecast, percent)
2025	N/A	11,536	N/A	N/A
2026	11,306	11,378	72	-1.4
2027	11,347	11,289	-58	-0.8

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1 **Request IR-24:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 4 Load Forecast**

4
5 **On page 26, NS Power noted that the four OATT MEUs will be taking a portion of their load**
6 **through the Municipal Tariff so load adjustments were made for the Municipal class and the**
7 **BUTU. What is the related impact on peak demand and total energy in 2026 and 2027?**

8
9 **Response IR-24:**

10
11 Load added under the municipal tariff for rate making purposes increased the underlying load
12 forecast by approximately 85 GWh. Peak would be unchanged overall as the forecast assumes the
13 full municipal peak would be served by NS Power regardless of the energy supply.

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Request IR-25:

References:

- (1) On pages 21 and 98 of the application, NS Power requests that BCF amounts attributable to FAM customers be set at “smoothed” amounts of \$927.3 million for 2026 and \$850.9 million for 2027.**
- (2) On Page 27 of the application, NS Power notes the forecast fuel and purchased power costs for the two-year test period amount to \$1.8 billion, with \$919 million in 2026 and \$918 million in 2027.**
- (3) On page 27 of the application, footnote 1, NS Power notes, “Total Fuel and Purchased Power including OATT MEUs taking partial bundled Municipal Tariff results in \$924.3 million in 2026 and \$925.0 million in 2027.”**
- (4) On page 27 of the application, NS Power says it “is seeking approval of new Base Cost of Fuel (BCF) amounts for FAM customers in 2026 and 2027 as set out in FOR-07 Attachment 1.” FO-07, Attachment 1, shows Total Fuel and Purchased Power of \$917.5 million for 2026 and \$917.3 for 2027.**
- (5) In OR-01 Attachment 1, cell L348 shows “Base Cost of Fuel” amounts for “Total FAM Classes” for 2026 Standard (\$849.35 million), 2027 Standard (\$841.41 million), 2026 Smoothed (\$864.92 million) and 2027 Smoothed (\$823.98 million).**
- (6) In OE-01A, Attachment 1, a total fuel and purchased power amount for 2026 is shown in cell N53 and in OE-01A, Attachment 2, a total fuel and purchased power amount for 2027 is shown in cell N58.**

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- 1 **(a) Do the amounts in reference 1 include the OATT MEUs and PHP as FAM customers?**
2
- 3 **(b) Please provide the corresponding “unsmoothed” amounts for the “smoothed”**
4 **amounts in reference 1.**
5
- 6 **(c) Please reconcile the amounts in reference 1 to the amounts in reference 2.**
7
- 8 **(d) Please reconcile the amounts in reference 1 to the amounts in reference 3.**
9
- 10 **(e) Please reconcile the amounts in reference 1 to the amounts in reference 4.**
11
- 12 **(f) Please reconcile the amounts in reference 1, and their corresponding “unsmoothed”**
13 **amounts (provided in (b)) to the amounts in reference 5.**
14
- 15 **(g) Please reconcile the amounts in reference 1 to the amounts in reference 6.**
16

17 Response IR-25:
18

- 19 (a) Yes; however, a portion of PHP load in 2027 (506 GWh) will not be priced at BCF rates
20 as it will be supplied by electricity produced by the Goose Harbour Lake Wind Farm¹ and
21 will be subject to a separate fixed \$/MWh charge. The revenue related to 506 GWh is
22 treated as below-the-line revenue, reducing the BCF amount attributable to FAM
23 customers.
24

- 25 (b) Please refer to the tables below for the smoothed and unsmoothed BCF (including PHP).
26

\$ Million	2026	2027	Source
Smoothed BCF	864.9	824.0	OR-01 Att 1 2026 smoothed and 2027 smoothed tabs cell W348

¹ Section 4AA of Nova Scotia's Electricity Act (SNS 2004, c 25) governs and explicitly enables sleeved power purchase agreements (PPAs).

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ATL PHP BCF	62.4	26.9	OR-01 PHP tab column N
Total BCF smoothed	927.3	850.9	

\$ Million	2026	2027	Source
Unsmoothed BCF	849.3	841.4	OR-01 Att 1 2026 smoothed and 2027 std tabs cell W348
ATL PHP BCF	62.4	26.9	OR-01 PHP tab column N
Total BCF unsmoothed	911.7	868.3	

(c-d)

- The amounts in reference 1 represent the amounts attributable to above-the-line customers (ATL) on a smoothed basis as seen in part (a).
- The amounts in reference 2 represent the total fuel and purchased power forecasts for 2026 and 2027 on an unsmoothed basis and include serving both ATL and below-the-line (BTL) customers prior to the inclusion of additional fuel costs to serve the four OATT MEUs under the Municipal Tariff.
- The amounts in reference 3 represent the total fuel and purchased power forecasts for 2026 and 2027 on an unsmoothed basis, and include serving both ATL and below-the-line (BTL) customers with the inclusion of additional fuel costs to serve the four OATT MEUs under the Municipal Tariff.

Please refer to the table below for reconciliation.

\$ Million	2026	2027	source
Total Fuel and Purchased Power	918.6	918.4	OE-01 Att 1 and Att 2 Output 1 tab
OATT MEUs additional Fuel Cost	5.7	6.6	SR-01 Att 5 and Att 6 Data Inputs Cell 140
Total Fuel and Purchased Power Including OATT MEU in Municipal Tariff	924.3	925.0	

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- 1 (e) FO-7 has Total Fuel and Purchase Power costs of \$918.6 million for 2026 and \$918.4
2 million in 2027. The amounts referenced in 4 are not referencing the Total, which can be
3 found on line 33. This includes both ATL and BTL Fuel and Purchased Power. Please see
4 part (c-d) to explain the differences.
5
- 6 (f) The amounts provided in OR-01 are BCF prior to the inclusion of PHP. Please refer to
7 parts (a) and (b) to reconcile the difference.
8
- 9 (g) The amounts in OE-01 Attachment 1 and Attachment 2 represent Total Fuel and Purchased
10 Power as outlined in the response to part (c-d).

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Request IR-26:

Reference: Exhibit N-3 GRA Direct Evidence, Section 5 Fuel and Purchased Power

On page 27 of the application, NS Power states, “To facilitate having more uniform increases across the two test years, NS Power has adjusted the BCF fuel rates to produce an overall smoothed increase in the total rates. This results in NS Power setting rates to have an over-collection of fuel costs in 2026 and then having a corresponding under-collection of fuel costs in 2027.

(a) Please confirm, or explain otherwise, that only the base cost of fuel has been smoothed and that no non-fuel costs have been smoothed over the test years (i.e., all non-fuel costs are fully reflected in the revenue requirement for each year).

(b) Please confirm, or explain otherwise, that the overcollection of fuel costs in 2026 will be a positive adjustment to the FAM balance in 2026 that is intended to be fully reduced by the under-collection of fuel costs in 2027.

(c) Please confirm, or explain otherwise, that unless fuel and purchased power costs in 2028 decline relative to 2027, NS Power will need to reset its base cost of fuel for 2028 to avoid once again growing an unrecovered FAM balance.

(d) Assuming NS Power’s costs in 2028 are identical to 2027, what percentage increase in NS Power’s (i) average fuel rate and (ii) average class rates in 2028 would be necessary to make up the planned shortfall in fuel cost recovery in 2027?

Response IR-26:

(a) Confirmed.

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(b) Confirmed.

(c) Not confirmed. Load changes can also influence collection amounts. NS Power would be required to update its BCF in 2028 in any event as the GRA Application only resets the BCF in 2026 and 2027. If load were to stay constant and fuel costs did not decline a BCF change would be required to avoid under recovering costs in 2028.

(d) Assuming NS Power's costs in 2028 are identical to 2027 and also assuming that class loads in 2028 are identical to 2027, the percentage increases would be approximately 1 percent.

2028 ATL Revenue excluding PHP (in millions of \$'s)				
	Priced at 2027 Smoothed Rates	Priced at 2027 Standard Rates	Variance	% Variance
Fuel	\$824.0	\$841.4	\$17.4	
Non-Fuel	<u>\$966.8</u>	<u>\$966.8</u>	<u>(\$0.0)</u>	
Total	\$1,790.7	\$1,808.2	\$17.4	1.0%

Source: 2026-2027 GRA OR-01 Att 01

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1 **Request IR-27:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 5 Fuel and Purchased Power**

4
5 **On page 29 of the application, NS Power states:**

6
7 **NS Power's currently approved version of the Confidential Fuel Manual,**
8 **which sets out the requirements for fuel and purchased power procurement,**
9 **is included in Standardized Filing OE-01F...**
10

11 **(a) Please confirm, or explain otherwise, that the version of the Fuel Manual referenced**
12 **in this statement, and attached as OE-01F, is Revision #14 dated October 17, 2024.**

13
14 **(b) Please confirm, or explain otherwise, that Revision #14 was filed with the Nova Scotia**
15 **Utility and Review Board by NS Power in Matter M11947 for information purposes**
16 **because the Fuel Manual is not approved by the Board.**

17
18 **(c) Please confirm, or explain otherwise, that the Nova Scotia Utility and Review Board**
19 **letter in Matter M11947 dated October 31, 2024, noted that there is no approval or**
20 **acceptance of the Fuel Manual and that NS Power is responsible for ensuring it**
21 **manages its fuel portfolio in a prudent manner in the best interests of its customers.**

22
23 **(d) Please explain the reference to the "approved" version of the Fuel Manual on page 29**
24 **of NS Power's application.**

25
26 **Response IR-27:**

27
28 **(a-b) Confirmed.**

29
30 **(c) NS Power confirms that the referenced wording appears in the identified letter from the**
31 **Board.**

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1 (d) The word “approved” at the beginning of the second full paragraph on Page 29 refers to
2 NS Power’s internal management approval status. In bringing forward the revisions in the
3 GRA, NS Power is seeking to ensure a proper record and transparency regarding changes
4 to the Fuel Manual. All changes were reviewed with the FAM Small Working Group and
5 no exceptions were identified. One point of clarification that NS Power wishes to make in
6 relation to the above referenced paragraph on page 29 of the GRA is that the reference to
7 Section 17 in that paragraph, should be to Section 16.

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Request IR-28:

References:

(1) On pages 21 and 98 of the application, NS Power seeks Board approval of “administrative” changes to the introduction to Appendix Q (the Hedging Plan) of the Fuel Manual.

(2) On page 35 of Appendix 5A, NS Power notes there is no legislative requirement for the Board to approve NS Power’s Hedging Plan.

(a) Please confirm, or explain otherwise, that Nova Scotia Utility and Review Board approval was explicitly required by legislation for NS Power’s “Fuel Stability Plan” for a “Rate Stability Period” spanning the years 2017, 2018 and 2019, which included “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”.

(b) Please confirm, or explain otherwise, that the Nova Scotia Utility and Review Board, in its decision approving NS Power’s Fuel Stability Plan (2016 NSUARB 129), the Nova Scotia Utility and Review Board noted:

[52] For the first time, since the implementation of the FAM, the Board is required, pursuant to s. 6 of the *EPIA*, to approve the hedging strategies or mechanisms to be used by NSPI to manage fuel costs during the Rate Stability Period.

[53] Since inception of the FAM, NSPI has undertaken hedging activities and the prudence of those activities was then reviewed as part of the FAM audit process. That meant that shareholders were at risk in the event hedging was done imprudently. During the Rate Stability Period, 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.

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1 **(c) Please confirm, or explain otherwise, that NS Power agrees that it is responsible for**
2 **ensuring it engages in hedging practices in a prudent manner in the best interests of**
3 **its customers.**

4
5 **(d) Please confirm whether NS Power's proposed changes to Appendix Q of its Fuel**
6 **Manual and its Hedging Plan have been filed for information purposes in this**
7 **proceeding or if NS Power is actually seeking an order approving these changes. If**
8 **the latter, please explain why, given that the Fuel Manual is not approved by the**
9 **Board and the Hedging Plan was approved only for the Fuel Stability Period from**
10 **2017-2019 because of the specific statutory requirement to do so at that time.**

11
12 Response IR-28:

13
14 (a) Confirmed. Board approval was explicitly required by legislation for a Rate Stability
15 Period spanning 2017, 2018, and 2019.

16
17 (b) Confirmed.

18
19 (c) Confirmed.

20
21 (d) Confirmed. NS Power's intent was not to introduce confusion, but rather to note that the
22 Fuel Manual, filed for information purposes only, is intended to continue in effect beyond
23 the Rate Stability Period. Therefore, all reference to distinct time periods have been
24 removed. The reference in section 2.3, number 4 of the Direct Evidence simply seeks
25 confirmation that the Fuel Manual, as provided, remains the framework for ongoing use.

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1 **Request IR-29:**

2
3 **Reference: Exhibit N-5, Appendix 5B, Fuel Hedging Plan**

4
5 **(a) What is the base document from which the tracked changes in Appendix 5B have**
6 **been made?**

7
8 **(b) Is there any reason why some of the tracked changes in Appendix 5B are in blue and**
9 **some are in red. If so, please explain.**

10
11 **Response IR-29:**

12
13 **(a) The tracked changes in Appendix 5B were based on a June 2021 version of the Fuel**
14 **Hedging Plan (FHP) as filed with the last GRA.**

15
16 **(b) Some of the tracked changes are in blue and some are in red representing different rounds**
17 **of updates since the last FHP was filed. The tracked changes in red represent the most**
18 **recent round of updates to reflect a FHP that is not tied to a specific period.**

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1 **Request IR-30:**

2
3 **Reference: Exhibit N-5, Appendix 5C, Letter from Minister of Environment and Climate**
4 **Change, March 25, 2025**

5
6 **Please provide a copy of the March 24, 2025, letter from Mr. Pickles, and any supporting**
7 **information for NS Power's request for flexibility, including its proposed recovery plan.**

8
9 Response IR-30:

10
11 Please refer to Attachment 1 for a copy of the letter from Mr. Pickles. Please also refer to NSEB
12 IR-31.

March 24, 2025

The Honorable Tim Halman
Minister Nova Scotia Environment and Climate Change
PO Box 442
Halifax, NS, B3J 2P8

Dear Minister Halman,

Re: Nova Scotia Power Inc. (NS Power or the Company) – Request for SO2 Emissions Variance

While NS Power was able to comply with SO2 air emissions limits in 2023 and 2024 as set out in the Air Quality Regulations, the compliance has been costly for customers and has presented challenges for NS Power's generation fleet. NS Power's projections show that the SO2 annual emissions limits presently in the regulations would drive incremental cost of approximately \$175-\$200 million over the 2025–2027 time frame, due mostly to the delays with additional renewable energy installations which are now expected to be online later in the decade.

To protect customer affordability and system reliability, NS Power is requesting a variance, pursuant to Section 61 of the Environment Act, with respect to the requirements of Section 1(10)-(14) of Schedule C of the Air Quality Regulations (the "Regulations"). NS Power's request relates to the timing of the SO2 compliance limits set out in those provisions. The requested variance would adjust the timing of the implementation of the SO2 emission limits while resulting in the same or lower total emissions as those established by the identified provisions. Such a variance would provide better alignment of SO2 compliance with Nova Scotia's overall decarbonization efforts and the path to net-zero emissions, while achieving compliance with the existing caps on total SO2 emissions during the multi-year period in question. NS Power is committed to taking all steps to reduce SO2 emissions in a way that ensures a reliable system and lowest costs for our customers.

The NS Power proposed plan would allow for SO2 annual limits flexibility to reduce the cost of compliance in the 2025-to-2027 time frame, while reducing SO2 emissions limits between 2030 and 2034.

This proposed plan also includes the recovery of 14.4 kt SO2 variance associated with the COV previously issued for the 2022 annual SO2 limit exceedance, in the 2030-2034 recovery period.

To achieve the Fuel and Purchased Power cost savings for customers, NS Power requires annual SO2 air emissions limits in the initial years of the next 10-year period to be higher than those currently provided for by Section 1 of Schedule C of the Regulations and lower in the later years, which more closely coincides with the planned completion of new renewable energy facilities.

Specifically, NS Power requests SO₂ emissions limits to be 45 kt for 2025, 45 kt for 2026, and 40 kt for 2027. The cumulative SO₂ limit for the period between 2026 and 2029 of 104 kt we request be changed to 141 kt. For 2030 to 2034 inclusive, NS Power proposes a reduction of the emission allowances below those currently provided for by the Regulations, by reducing them from 20 kt to 9 kt per annum.

The proposed changes to the timing of allowable annual emission limits, in accordance with the foregoing, would result in the cumulative SO₂ emissions in the 2025 to 2034 period remaining net neutral, or lower, due to significantly lower projected SO₂ emissions in 2030 and beyond associated with decarbonization efforts.

As noted, NS Power's request for a variance is limited to the timing of the SO₂ emission caps. NS Power is not requesting variance to any other requirements of the Regulations. Specifically, we propose that subsections 1(10), (12) and (13) be varied as indicated below:

(10) Beginning January 1, 2025, and in each calendar year after that, the annual emissions of sulphur dioxide from fossil-fuel-fired thermal generating stations owned or operated by Nova Scotia Power Incorporated and affiliated companies must not in the calendar year exceed, in the aggregate, ~~28,000~~ 45,000 t.

(12) From January 1, 2026, until December 31, 2029, the total emissions of sulphur dioxide from fossil-fuel-fired thermal generating stations owned or operated by Nova Scotia Power Incorporated and affiliated companies must not exceed, in the aggregate, ~~104,000~~ 141,000 t.

(13) Beginning January 1, 2030, and in each calendar year after that, the annual emissions of sulphur dioxide from fossil-fuel-fired thermal generating stations owned or operated by Nova Scotia Power Incorporated and affiliated companies must not in the calendar year exceed, in the aggregate, ~~20,000~~ 9,000 t.

Figure 1 summarizes the proposed variance and projected SO₂ releases. Note that the projected SO₂ annual releases are slightly lower than the requested limits, providing a required buffer to manage inherent uncertainties with respect to incremental renewable energy commencement timing, and fluctuations in fuel and imported energy availability.

Figure 1: Annual SO₂ air emissions variance in context of present SO₂ annual limits

SO ₂ [kt]	Present Limits	Flexibility Limits	Projected Release	Variance	Recovery
2025	28	45	43	15	
2026	26-28	45	43	17	
2027	26-28	40	34	8	
2028	26-28	28	28	2	
2029	26-28	28	26	-	
2030	20	9	8		12
2031	20	9	8		12
2032	20	9	8		12
2033	20	9	6		14
2034	20	9	6		14
Subtotal				42	
Variance from 2022				14.4	
Total	232	231	210	56.4	64

In the development of the proposed compliance plan, NS Power has considered the following:

Affordability

- NS Power's modelling shows that the current annual SO₂ limits drive additional fuel cost in the range of \$175 - \$200 million, resulting in increased rate pressure as fuel costs are a direct pass through to customers.
- The projected cost increases are due largely to higher-cost low sulphur coal, which is priced at a premium, additional natural gas from the U.S. which is difficult to secure, and price prohibitive and uneconomic imports.

System Reliability

- The higher cost low-sulphur coal blends have stretched the design parameters of the solid fuel fleet in 2023 and 2024. The fleet is designed to operate on medium sulphur coal, and moving to maximum low sulphur coal has led to opacity issues which prevent the coal fired units from reaching full load, and thus increasing reliance on natural gas, diesel, and emergency import energy, while delaying maintenance on coal fired units.
- In 2023 and 2024, and as projected for 2025-2027, increased natural gas and import energy are at levels which would otherwise be considered uneconomic or unreliable. At these levels, natural gas and imports are subject to availability and supply reliability issues, along with price uncertainty.
- Due to the very tight compliance margins in such a compliance plan, even relatively minor shortages in import energy and natural gas supply may jeopardize the plan, while still incurring significant costs and as the result of uncertainty with base load, relatively minor gains in total system energy demand can make the compliance plan more challenging and more expensive.

United States Markets Exposure

- NS Power is working on reducing risk exposure to United States fuels markets by maximizing fuel purchases from domestic and other international sources where available and economic.

Ambient Air Quality

- NS Power will make sure that the flexibility with the timing of annual SO₂ limits does not affect our compliance with Ambient Air Quality Standards.
- NS Power's coal fleet flexibility allows for reduction of power production in certain locations if the weather conditions are such that ambient air quality may be affected.
- Petcoke use will be limited to Point Aconi. No petcoke will be used in any coal fired generating units.
- Furthermore, NS Power plans to use only low-sulfur coal blends at the Trenton generating facility which is the most inland installation and has the most potential to affect ambient air quality.

In closing, NS Power takes our responsibility to meet all our compliance obligations and government's climate goals extremely seriously and I want to reiterate our commitment and efforts to meet these goals while ensuring reliability and lowest cost for our customers. We believe that the revised plan is responsive to the Department's objectives and ensures our ability to maintain a reliable electricity system for our customers.

Thank you again for your consideration of this revised plan and the requested variance.

Yours truly,



Dave Pickles
Chief Operating Officer, NS Power

cc. Peter Gregg, CEO, NS Power Inc.
Judith Ferguson, EVP Regulatory, Legal, and Government Relations
Lora MacEachern, Deputy Minister, Department of Environment and Climate Change
Matt Seaboyer, Director, Air Quality & Resource Management, ECC

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Request IR-31:

Reference: Exhibit N-3 GRA Direct Evidence, Section 5 Fuel and Purchased Power, Figure 5-4 p. 31

- a) Please explain why shifting sulphur dioxide compliance limits from 2025-2029 to 2030-2034 does not require future customers to pay for the “approximately \$160 million” decrease in NS Power’s revenue requirement over the test years (and presumably additional decreases in the cost of fuel and purchased power in 2025, 2028 and 2029).**
- b) Please compare NS Power’s forecast sulphur dioxide compliance costs for the 2030-2034 period under the original sulphur dioxide limits and the limits that are reduced by more than half under the certificate of variance.**
- c) If it is NS Power’s position that compliance cost increases associated with the significant decreases in sulphur dioxide limits in 2030-2034 will be mitigated by other factors, such as the elimination of coal fired generation in 2030, please list all such factors that NS Power has assumed, what needs to occur for these assumptions to be borne out, and NS Power’s risk assessment and mitigation plan in the event these assumed factors do not materialize in the time frame assumed.**

Response IR-31:

- (a) Compliance with NS Power’s previous sulphur dioxide (SO₂) emissions limits for the 2025–2029 period would have resulted in significant incremental costs to customers. SO₂ compliance at the previous levels would have required a shift toward natural gas and heavy fuel oil (HFO) generation. These options are more expensive than coal and result in higher greenhouse gas (GHG) Output-Based Pricing System (OBPS) costs in the near term due to the performance standards applied to different fuel types. Additionally, the use of low**

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1 sulphur fuel blends at Langan and Point Tupper significantly limit the maximum unit
2 output, which introduces further reliability risks to the system.

3
4 The SO₂ Certificate of Variance (CoV) offers better alignment between SO₂ emissions and
5 GHG OBPS compliance. It enables more efficient use of the fossil fuel fleet in the short
6 term, helping bridge the gap until new renewable projects and new fast acting generation
7 capacity come online.

8
9 After 2030, with substantial new renewable generation expected, new fast-acting
10 generation resources available, and a corresponding reduction in fossil fuel use for baseload
11 generation, long-term models indicate that SO₂ emissions will naturally fall below the CoV
12 limits. As a result, no additional SO₂ compliance costs are anticipated.

13
14 For greater clarity, realigning SO₂ emissions limits over the decade leads to significant cost
15 savings in the early years, without incurring additional costs in the latter half.

16
17 (b) Please refer to part (a) for an explanation of how there are no additional SO₂ compliance
18 costs in the 2030-2034 timeframe. Please refer to Figure 1 for comparison of original SO₂
19 limits, CoV SO₂ limits, and updated forecast SO₂ emissions.
20

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Figure 1: Comparison of original SO₂ limits, CoV SO₂ limits, and forecast SO₂ emissions

Year	Original SO ₂ Limit [kt]	CoV SO ₂ Limit [kt]	Projected SO ₂ Release [kt]
2025	28	45	41
2026	26-28	45	40
2027	26-28	40	30
2028	26-28	28	26
2029	26-28	28	11
2030	20	9	1
2031	20	9	1
2032	20	9	1
2033	20	9	1
2034	20	9	1
Total	232	231	170

(c) A detailed description of the long-term resource plan supporting this conclusion, including risk management considerations, is outlined in NS Power's Path to 2030 (2024 Update), filed as NSEB IR-003 Attachment 1. This report outlines the how NS Power and the Province of NS are working to achieve the 2030 Decarbonization Objectives. Briefly, NS Power anticipates that potential compliance cost increases associated with the significant reduction in sulphur dioxide (SO₂) limits for 2030–2034 will be mitigated by several key factors:

- Addition of new renewable energy resources (e.g., wind and solar).
- Deployment of new non- or low-SO₂-emitting dispatchable generation assets (e.g., battery storage, fast-acting dual-fuel generation).
- Conversion of existing coal-fired units to alternative fuels (e.g., natural gas, HFO).
- Implementation of new renewable integration assets to support inverter-based renewable generation (e.g. Reliability Tie, synchronous condensers).

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1 Conditions for the projects above to be successfully developed include:

- 2 • Timely procurement, completion and commissioning of renewable and new fast-acting
3 generation projects.
- 4 • Successful regulatory approvals and stakeholder support for project development.
- 5 • Supply chain reliability for key project components including high voltage equipment.
- 6 • Availability of talent to support project execution and integration into the system
- 7 • Continued alignment with provincial and federal decarbonization policies.

8

9 NS Power remains closely engaged with the Province and the IESO-NS to understand any
10 schedule changes that could impact the path to 2030 timeframes and will work
11 cooperatively with those parties and customers on alternate solutions. For example, NS
12 Power is assessing fuel switching of additional coal generating units to fulfill capacity
13 requirements should planned capacity additions by the Province/IESO-NS, including fast
14 acting generation and wind, occur outside the currently anticipated timeframes. Such
15 solutions support SO₂ reductions post-2030 while maintaining system capacity
16 requirements as the grid transitions.

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Request IR-32:

Reference: Exhibit N-5, Appendix 5A Fuel and Purchased Power, p.8

It is noted in section 1.1.3 that “NS Power does not use heavy fuel oil (HFO) as a primary fuel to generate electricity due to its high cost relative to natural gas or solid fuels”. Board staff notes that the monthly FAM reports for January and February 2025 showed heavy fuel oil consumption significantly over budget. The reason included in the reports was due to increased total system requirement and lower than budgeted solid fuel generation (which was due to sulphur dioxide emission constraints).

(a) Has NS Power considered the use of a Virtual Power Plant or other means of reducing consumption in instances such as this instead of switching to use of a costly source of fuel such as heavy fuel oil?

(i) If so, please provide details.

(ii) If not, why not?

Response:

In January and February 2025 NS Power used fuel switching from natural gas to HFO when the cost of HFO was lower than the cost of natural gas, providing savings to customers. While demand response programs can relieve temporary load peaks, they would be of limited use during sustained periods of high natural gas prices.

(a) NS Power has piloted Virtual Power Plants (VPPs) and Distributed Energy Resource Management Systems (DERMS) during the Load Control Demonstration Project (M03589), alternatively referred to as Power Shift Atlantic, and Smart Grid Nova Scotia Project (M11621). One of the findings from the SGNS project was:

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1 A DERMS platform can play a powerful role in the central management of
2 DERs to achieve various customer and utility benefits, but other options for
3 the management of DERs are available and effective while adoption rates
4 are low. An effective DERMS platform requires robust monitoring and
5 control capabilities, seamless integration with various DERs, real-time
6 communication and coordination protocols, and advanced analytics to
7 optimize the operation and management of the DERs on the grid to create
8 and capture value associated with the sharing of this technology with
9 customers.

- 10
- 11 (i) NS Power is in the process of developing a Distributed Energy Resource Integration
12 Roadmap (DERIR) which will provide prioritization of potential DER-related
13 initiatives and guiding principles for DER integration in Nova Scotia. The
14 Company will finalize and submit the DERIR report to the Nova Scotia Energy
15 Board by year-end 2025.

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1 **Request IR-33:**

2
3 **Reference: Exhibit N-5, Appendix 6A (FAM Framework) and 6B (FAM Plan of**
4 **Administration).**

5
6 **NS Power proposes a change to s. 3.2.8 of the FAM POA to include costs associated with**
7 **renewable energy programs (e.g., on bill credits for community solar programs).**

8
9 **(a) Please explain how the proposed language distinguishes between program related**
10 **costs that should be included under cost of service and rate design principles and costs**
11 **that, because of statutory restrictions, cannot be recovered from program**
12 **participants and must be subsidized by other customers.**

13
14 **(b) Please comment on the appropriateness of including the following additional**
15 **language to the proposed change (underlined): “and costs associated with renewable**
16 **energy programs (e.g. on bill credits for community solar programs) when such costs**
17 **cannot be recovered from program participants.”**

18
19 **Response IR-33:**

20
21 **(a-b) The Company’s proposed revision to Section 3.2.8 of the POA is intended to capture**
22 **customer renewable energy program-related costs that, due to statutory or program-specific**
23 **limitations, are not recoverable from participating customers and, therefore, require**
24 **recovery through the FAM mechanism. This includes programs where cost recovery is**
25 **explicitly restricted to non-participants (such as the Community Solar¹ and Green Choice**

¹ Section 4 of the *Community Solar Program Regulations* provides “A subscriber must not be charged any additional fees by NSPI or a project owner to participate in the community solar program,” and Section 5 provides “A subscriber is billed by NSPI for their electricity consumption but will receive a bill credit for the amount of solar energy generated from their subscription.”

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1 Programs²), as well as those that, while not statutorily mandated, may result in costs unable
2 to be recovered by participants.

3
4 In this context, the additional language proposed by the Board in part (b), “when such costs
5 cannot be recovered from program participants,” provides helpful clarification and aligns
6 with the underlying intent of the provision. NS Power supports its inclusion to ensure
7 transparency and consistency in recovery of such costs.

² Section 12 of the *Green Choice Program Regulations* provides “(1) Participants must incur no fees, costs or penalties associated with the Green Choice Program outside of those listed in these regulations. (2) A fixed administrative cost charged under these regulations must not exceed \$0.001 per kWh of eligible subscribed electricity contracted by the participant, up to a total of \$100 000 per participant annually.” Section 31(2) of the *Electricity Act* provides, “Nova Scotia Power shall make any necessary billing adjustments to ensure that participants are not subject to any costs related to Nova Scotia Power’s compliance with the *Greenhouse Gas Emissions Regulations* made under subsection 28(6) and Section 112 of the *Environment Act* for electricity procured under the Green Choice Program.”

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Request IR-34:

Reference: Exhibit N-3, GRA Direct Evidence, Section 6 Fuel Adjustment Mechanism and Appendix 6B

NS Power notes that it has proposed changes to the FAM Plan of Administration to move some costs previously included in OM&G to the FAM. Board staff notes that Ash Hauling costs and Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs have both been added to the POA, and that the Board had previously told NS Power that it would only consider moving these costs to the FAM in conjunction with a GRA (M11127).

(a) Please confirm, or clarify otherwise, these are the only costs proposed to move from OM&G to the FAM.

(i) If not confirmed, please identify the other OM&G costs that NS Power has proposed to move to the FAM.

(b) Please provide the amount included in the 2024 test year forecast in the previous GRA for each of these items.

(c) Board staff notes that there is a \$1.5 million decrease in contracts under Power Production Head Office expense in 2026 compared to 2024 actuals related to removal of ash hauling costs, and a minor decrease in contracts under Tufts Cove and Combustion Turbines related to removal of ash hauling costs. It is not apparent to Board staff where the Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs have been removed from the OM&G forecast. Please confirm, or clarify otherwise, where these costs have been removed from the OM&G forecasts for 2026 and 2027.

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Response IR-34:

(a) As noted in the preamble of this IR the POA redline indicates that Ash Hauling costs and Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs have been added as allowable fuel costs under the FAM. However, the POA redline also includes costs related to the third-party production bonuses and penalties for NS Power-owned wind facilities (see section 3.2.18). To be clear, the three costs added in the redline POA, submitted as Appendix 6B, include the following:

1. Section 3.2.2 (Solid Fuel) and Section 3.2.3 (Heavy Fuel Oil) addition of Ash Haulage costs;
2. Section 3.2.3 (Heavy Fuel Oil) addition of Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs; and
3. Section 3.2.18 addition of NS Power-owned Wind Generation Variable Production Costs which includes third-party production bonuses and penalties for NS Power-owned power production.

The NS Power-Owned Wind Generation Variable Production Costs were part of the 2023 application to revise the POA (M11127) and the Board identified these costs as eligible for consideration in a future GRA proceeding in the Decision dated September 6, 2023. In the Decision, at the top of page 3, the Board stated as follows:

Given the nature of the **first three costs**, the Board is willing to consider inclusion at a future date, in conjunction with a GRA. (emphasis added)

Earlier in the Decision, on page 1, the Board identified the first three costs:

NS Power's application included a request to revise the FAM POA to allow for inclusion of four costs previously not included in the FAM: **the premium/discount component of the maintenance contract for Nuttby Wind Farm**, ash haulage costs for solid fuel and heavy fuel oil, Tufts Cove

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wharf /buoy chain inspection and maintenance, and third-party compliance
program costs for heavy fuel oil. (emphasis added)

In the Decision regarding M11127, the Board approved the third-party compliance
program costs for heavy fuel oil as allowable fuel costs beginning in 2023.

(b) Please refer to the table below.

	2024 GRA Compliance (\$)
NSP Owned Variable Production Costs	954,361
Ash Haulage costs	912,796
Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs*	50,000
Total	1,917,158
*The Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs were forecast as part of scheduled plant maintenance OMG in the 2024 GRA Compliance Forecast and is not separately identifiable. This is an estimation based on historical actuals.	

(c) The Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs have been removed
from the Tufts Cove and Combustion Turbines OM&G forecast for 2026 and 2027. The
NS Power-Owned Variable Production Costs, which includes third party production
bonuses and penalties for NS Power-owned Wind Generation, referred to in part (a) have
been removed from the Wind Hydro & Solar OM&G forecast for 2026 and 2027.

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1 **Request IR-35:**

2
3 **Reference: Exhibit N-5, Appendix 6A Fuel Adjustment Mechanism Plan of Administration,**
4 **Section 3.1.**

5
6 **Why has NS Power removed the reference to carrying costs being paid by customers paying**
7 **a balance owing over time?**

8
9 Response IR-35:

10
11 The Company proposed the Section 3.1 Fuel Adjustment Mechanism (FAM) Plan of
12 Administration (POA) revisions to reduce the overlap of provisions within both the POA and the
13 FAM Tariff. The removal of this specific reference¹ from the POA does not amount to the
14 exclusion of transitioning customer responsibility for carrying costs where payments are made
15 over time. Consistent with Section 1.2 of the FAM Framework,² any FAM balances paid by, or
16 returned to, customers over time include carrying costs to ensure that both customers and NS
17 Power are kept whole. The application of carrying costs is also reflected in the monthly FAM
18 reports, as the FAM calculation models are designed to apply interest to the FAM balance on a
19 monthly basis.

¹ The specific reference on page 12 of Appendix 6B is, “Where payment is made over time, the transitioning customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.”

² Please refer to Section 1.2.2 which provides “At year end, the under- or over-recovered amount (plus the applicable interest) will be the total FAM deferral amount for that year,” and Section 1.2.3, footnote 2, which states “Although the actual AA figures will be based on 12 months of actuals, there will be a BA based on the difference between the forecast sales and the actual sales and as a result of financing costs on the AA balance while it is being collected or refunded. [...]”

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Request IR-36:

Reference: Exhibit N-3 GRA Direct Evidence, Section 2.2 FAM Treatment

- a) Please reconcile the forecast total FAM balance owing from customers at the end of 2025 of approximately \$94 million (from the August 2025 monthly FAM report) with the FAM deferral balance forecast in RB-2-16.**
- b) Has the annual amount owing to Invest Nova Scotia related to the \$117 million receivable been incorporated into the BCF amounts in 2026 and 2027?**
 - i. If not, why not?**
- c) Please confirm NS Power intends to file a FAM AA/BA application in Q4 of 2025.**
 - i. If confirmed:**
 - a. Have the estimated rate adjustments been presented to and discussed with the customer representatives?**
 - b. Please provide the estimated rate impacts.**
 - ii. If not confirmed:**
 - a. Please explain the treatment of the AA/BA balances at the end of 2025.**

Response IR-36:

- (a) FAM balance reconciliation is presented in Figure 1 below. The higher under-recovery as reported in the August Monthly Report is primarily driven by the increase in actual FAM Fuel Costs as of August 2025 of \$68.9 million. The increase in FAM fuel costs was primarily the result of increased HFO consumption during winter 2025 to meet the system demand. As NS Power did not receive the SO₂ emissions Certificate of Variance (CoV) until April 2025, NS Power was constrained by how much coal could be consumed at the thermal units, due to low-sulphur coal blend effect on precipitator operation, which resulted in these units having to use HFO to reach full capacity. In addition, there was a significant**

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increase in the market price of natural gas during winter 2025, which resulted in HFO being more economical than natural gas to run at Tufts Cove. As a result of the increased HFO consumption, there was an increase in the amount of OBPS expense required to be recorded in FAM fuel expense. The provincial legislation that increases the purchased power price for biomass energy at Brooklyn Power also contributed to the increase in FAM fuel costs.

The other main driver of the increase in the under-recovery in the FAM balance is the increase in forecast FAM fuel costs for the remainder of the year, i.e. September to December 2025. This is primarily due to the forecast used in development of the monthly FAM reports using assumptions from August 2024, meaning that the decrease in fuel costs as result of the SO₂ emissions CoV was not incorporated into the forecast. The forecast used for the GRA filing was completed in April 2025 and includes the SO₂ emissions CoV and the associated cost savings in fuel.

Figure 1: FAM Balance Reconciliation

FAM Over-Recovery per RB-2-16		(\$0.3M)
Change in actuals for January to August 2025		
Increase in Actual FAM Fuel Costs	\$68.9M	
Decrease in Actual BCF Revenue	\$4.0M	
Reduced Actual Interest Owed to FAM customers	\$0.8M	
Total Change as result of actuals		\$74.7M
Change in forecast for September to December 2025		
Increase in forecast FAM Fuel Costs	\$17.7M	
Reduced Interest Owed to FAM customers	\$1.7M	
Total Change as result of forecast amounts		\$19.4M
FAM Under-Recovery per August Monthly FAM Report		\$93.8M

- (b) No, the annual amount owing on the \$117 million is not incorporated into the BCF fuel cost or BCF rates for 2026 and 2027. Per M11393, the purposes of the FAM Asset Sale to Invest Nova Scotia was to reduce the required increase to fuel rates that would have been required under the normal FAM AA/BA process for collection of previously unrecovered fuel costs that NS Power is currently carrying. The \$117 million FAM Asset Sale was

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1 treated as a one-time reduction in the carrying balance of the FAM in April 2024. As the
2 interest rate on the repayment of \$117 million to Invest Nova Scotia is less than NS Power's
3 weighted average cost of capital, the removal of the \$117 million from FAM results in less
4 interest required to be recovered from customers. As directed in M11393, the \$117 million,
5 with interest, will be collected by NS Power on behalf of Invest Nova Scotia.

6
7 As shown in Section 2.2 of the Direct Evidence, BA-1 relates to the collection of the
8 amount owed to Invest Nova Scotia was approved on April 17, 2024 in M11393. The
9 amounts to Invest Nova Scotia and the amounts received from this rider are tracked outside
10 the FAM, meaning it has no associated fuel cost. NS Power remits the interest amounts to
11 Invest Nova Scotia on a quarterly basis. The GRA assumes that the separate rider will
12 continue to be in place through the GRA test period and as can be seen in OR-01
13 Attachment 1 in tab 2026 smoothed and 2027 smoothed column AG the FAM BA Rider
14 continues to collect this balance on behalf of Invest Nova Scotia. Also refer to PR-01
15 Attachment 25 for the proposed FAM Tariff where this rider remains in place.

16
17 (c) NS Power anticipates filing an AA/BA Application in Q4 of 2025.

18 (i) As part of the consensus GRA discussions, initial estimates of potential impacts
19 were discussed with stakeholders. As can be seen in NSEB IR-1 Attachment 1
20 NS Power has committed to working with certain customer classes to help
21 smooth or mitigate the overall impact of rate changes from these riders for the
22 2026/2027 test period.

23 (ii) NS Power has not completed the rate impact analyses with the final actual results
24 to September 30, 2025. The details will be provided in the FAM AA/BA
25 Application. The Company has not determined the date in which its next FAM
26 AA/BA Application will be filed but anticipates that the filing will be made prior
27 to the end of 2025.

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1 **Request IR-37:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence Appendix 5A**

4 **Prior general rate applications have included a Fuel Update in late August of the filing.**

5 **a) Please provide the date on which the fuel and purchased power assumptions in the**
6 **GRA application are based.**

7
8 **Response IR-37:**

9
10 The pricing date of the forecast was October 29, 2024. All other assumptions were dated October
11 2024 except for the sulphur dioxide (SO₂) assumptions which were updated in March of 2025.

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1 **Request IR-38:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence Appendix 5A**

4 **On page 34 of Appendix 5A, the application states that NSPML's forecast assessments for**
5 **the Maritime Link against NS Power are \$200.5 million in 2026 and \$203.9 million in 2027**
6 **(including \$41.5 million and \$40.6 million for 2026 and 2027, respectively related to interest**
7 **and principal on the \$500 million Federal Loan Guarantee).**

8 **a) Please explain the reason why Operating & Maintenance costs are forecast to increase**
9 **from \$21.7 million in 2026 to \$29.0 million in 2027.**

10
11 **Response IR-38:**

12
13 (a) The increase in NSPML's estimated O&M costs from 2026 to 2027 is primarily related to
14 expected submarine cable maintenance activities, including a full marine survey planned
15 for 2027.

16
17 Please note, the figures included in NS Power's General Rate Application for the Maritime
18 Link were based upon estimates prepared in mid-2024. Updated figures are included in
19 NSPML's 2026 Assessment Application which is currently being assessed by the NSEB.
20 The total assessment amount in the Application is for \$198.7 million, with the variance to
21 the \$200.5 million being primarily attributed to lower actual FLG2 costs. O&M costs of
22 \$22 million are detailed in NSPML's Application and are substantially similar to the 2024
23 estimate of \$21.7 million. Any variance to amounts included in NS Power's General Rate
24 Application and NSPML's Annual Assessments are balanced through the FAM.

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

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Request IR-39:

(a) Please provide the actual Bad debt expense and Write-offs of accounts receivable for 2019 to 2024 inclusive, as well as the estimated amounts 2025 to 2027 inclusive.

(b) If available, please provide these amounts by customer class.

Response IR-39:

(a) NS Power's net bad debt expense is comprised of write-offs, commissions and recoveries which are forecast on a cumulative basis. Please also refer to GT IR-50.

NS Power's actual net bad debt expense for 2019 to 2024 is as follows:

Year	Actual Net Bad Debt Expense
2019	4,777,945
2020	5,785,758
2021	2,280,327
2022	3,386,618
2023	3,843,434
2024	5,379,966

NS Power's estimated net bad debt expense forecast for 2025 to 2027 is as follows:

Year	Estimated Net Bad Debt Expense
2025	5,060,793
2026	5,162,009
2027	5,265,249

(b) NS Power does not track net bad debt expense by customer class.

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1 **Request IR-40:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 1.1 Support for 2026-2027 GRA**

4 **On page 8 of the application, NS Power notes that the GRA does not include costs related to**
5 **the cybersecurity attack. While not included in the forecasted revenue requirement, please**
6 **provide a breakdown of all costs NS Power anticipates it will incur in the test period due to**
7 **the cybersecurity attack, and its most recent forecast for each cost.**

8
9 **Response IR-40:**

10
11 NS Power has not prepared a 2026 forecast of recovery costs related to this incident. NS Power's
12 recovery efforts from the cybersecurity incident remain ongoing. Full restoration for major
13 capabilities is expected to progress through 2026.

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Request IR-41:

Please confirm, or clarify otherwise, that the total cost reduction in operating costs due to the consensus is \$9 million, made up of \$5 million allocated to administration (Appendix 7C, p.50), \$2 million allocated to customer service (Appendix 7C p.52), and \$2 million allocated to corporate adjustments (Appendix 7C, p.58).

Response IR-41:

Confirmed. In addition to the \$9 million decrease in Operating, Maintenance and General (OM&G) expense in each of 2026 and 2027, NS Power decreased Depreciation and Accretion expense and Regulatory Amortization expense per the terms of the settlement agreement with customer representatives. Please also refer to NSEB IR-1 Attachment 1 for the breakdown of the OM&G and regulatory amortization reduction.

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Request IR-42:

- (a) Please provide a listing showing the total number of 2026 forecast full-time equivalent employees (FTEs) included in each operating expense category compared to current (2025) actuals and the numbers included in the 2024 compliance filing. Please include in the listing a variance column showing the increased number of FTEs per category over 2024 compliance as well as the percentage increase per category.**
- (b) For increases in the number of FTEs that are greater than 10%, please explain why the additional FTEs are necessary.**

Response IR42:

- (a-b) Please see the table below for the number of FTEs included in the 2024 compliance forecast and 2026-2027 GRA Forecast. NS Power has restructured certain areas of the business since the time of the 2023-2024 GRA filing. NS Power cannot re-state the FTEs included in the 2024 Compliance forecast to match the updated structure on the requested timeline.**

NS Power's current number of FTEs is 2478. At this time NS Power does not have the reporting capability available to provide the breakdown requested for 2025.

The figures included for the 2026 and 2027 GRA have not been adjusted to reflect the \$9 million reduction in OM&G expense agreed to by NS Power as part of the settlement agreement with customer representatives. In addition, NS Power has recognized a vacancy adjustment of \$5.7 million in 2026 to recognize that not all these positions will be filled.

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	2024 Compliance	2026 GRA	2027 GRA	2026 GRA vs. 2024 Compliance	% Change	Explanation
Executive Management	4	4	4	-	0	
Legal and Corporate Secretary	12	11	11	(1)	-8	
Corporate Finance	33	33	33	-	0	
Communications and Public Affairs	10	15	15	5	50	Note 1
Human Resources and Safety	50	63	63	13	26	Note 2
Facilities, Procurement & Security	70	86	86	16	23	Note 3
Information Technology	204	239	244	35	17	Note 4
Regulatory Affairs	18	17	17	(1)	-6	
East Coast Energy Initiative	0	40	40	40	N/A	Note 5
Total Corporate Groups	401	508	513	107	27	
Head Office	20	20	20	-	0	
Thermal Plants	291	340	340	49	17	Note 6
Tufts Cove & Combustion Turbines	104	100	100	(4)	-4	
Solar, Hydro and Wind Energy	74	94	94	20	27	Note 7
Biomass	31	32	32	1	3	
Energy, Fuel and Risk Management	32	34	34	2	6	
Total Power Production	552	620	620	68	12	
Enterprise Asset Management & Project Implementation	118	116	116	(2)	-2	
Environment	24	30	30	6	25	Note 8
Customer Operations/Energy Delivery	769	950	918	181	24	Note 9
Customer Service/Customer Experience & Innovation	251	398	400	147	59	Note 10
NS Power Total	2115	2622	2597	507	24	

Note 1- Please refer to NSEB IR-061.

Note 2- Please refer to NSEB IR-062.

Note 3- Increase is due to system growth and increase in customer-requested work. The 2024

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1 Compliance forecast expected lower staffing levels due to the closure of two generating units at
2 the time of the 2023-2024 GRA.

3
4 Note 4- Please refer to Appendix 07A, Section 1.8 and GT IR-019.

5
6 Note 5- This is a new department that was not contemplated at the time that the 2024 Compliance
7 budget was developed.

8
9 Note 6- Primarily due to the assumption that two thermal units would be retired during the 2023-
10 2024 period. These units have been retained to serve customer load and provide system capacity.

11
12 Note 7- Primarily due to increased regulatory requirements driving increased investment, aging
13 Wind assets, increased resourcing for Dam Safety, increased resourcing for sustaining Mersey
14 Hydro operations and increased scope of the hydro capital program.

15
16 Note 8- Additional Environmental staff due to increased regulatory requirements related to
17 operation of NS Power's hydro and increased additional staff requirements on NS Power's
18 Mi'kmaw Relations team.

19
20 Note 9- Increased resourcing due to increased customer-requested work and increased investment
21 in system reliability. Please refer to Appendix 07A, section 1.5. The increases in FTEs in this
22 department are partially offset by decreases to the reorganization of NS Power's departmental
23 structure, with employees moving to Customer Experience and Innovation.

24
25 Note 10- Please refer to Appendix 07A, section 1.6. The departmental reorganization since the
26 development of NS Power's 2024 Compliance forecast has resulted in the movement of employees
27 from Energy Delivery to Customer Experience and Innovation.

REDACTED

Request IR-43:

Please specify all costs included in the application which are related to compensation for any Emera or Emera-related employees.

(a) Please name each employee and job title and provide a breakdown of those costs for each employee.

(b) Please specify any compensation for the President and CEO of Emera that is included in the Application.

Response IR-43:

(a-b) The President and CEO of Emera receives compensation from NS Power in the form of a fee for acting as the Chair of the Company's Board of Directors. The amount included in the Company's 2025 forecast is [REDACTED], and this amount is increased by 2 percent in each of 2026 and 2027. There are no other labour costs included in the application related to compensation for Emera or Emera-related employees. NS Power does receive corporate support services from affiliated companies and provides corporate support services to affiliated companies. The provision and charges for these services are in accordance with NS Power's Affiliate Code of Conduct and costing for these services is determined in accordance with NS Power's Cost Allocation Manual.

REDACTED

Request IR-44:

Please identify the number and percentage of employees who were eligible to receive a bonus, and the number and percentage that actually received a bonus, in any or all of the previous five years (i.e., 2020 to 2024, inclusive).

(a) What was the total amount of the bonus in each year?

(b) Provide a breakdown of the number and percentage of employees within each bonus category along with the associated bonus amounts.

(c) Please provide similar details regarding expected bonus payments in the application for 2026 and 2027.

Response IR-44:

(a-b) NS Power assumes the questions in this information request refer to the variable portion of employee compensation for non-union employees, which is part of an employee's base compensation as opposed to a bonus. Please refer to Confidential Attachment 1.

(c) Please see the table below:

	2026	2027
Regulated Variable Compensation Expense	8,976,215	9,193,322
Eligible Employees		

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Request IR-45:

Reference: Exhibit N-3 GRA Direct Evidence, Section 7 Operating Costs

Page 36 of the application refers to wage increases for both union and non-union employees.

(a) Please describe the current status of NS Power's collective agreement with its unionized labour force and identify the percent increase and the total salary costs included for 2026 and 2027.

(b) Are any non-unionized workers subject to the same or similar percentage increase in wages? Please provide details.

(c) Please provide the actual pension expense from 2015 to 2024, and 2025 forecast (in similar format to the response to Request IR-46 in M10431).

Response IR-45:

(a) The current collective bargaining agreement (CBA) with the International Brotherhood of Electrical Workers Local 1928 expires on March 31, 2026. As a result, there are no wage increases in the current CBA for 2026 or 2027.

(b) Yes, the average 2026 and 2027 wage increases are assumed to be the same for both union and non-unionized employees in the 2026-2027 GRA budget. Non-union wage increases are assumed to be effective at January 1st of each year. Union wage increases are assumed to be effective at April 1st of each year, due to the timing of the expiry of the current CBA.

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1 (c) Please see the table below:

Year	Pension recorded in OM&G	Pension recorded in Other Expense (Income)	Total Pension Expense
2015	49,039,000		49,039,000
2016	41,100,000		41,100,000
2017	35,980,266		35,980,266
2018	11,944,132	18,369,106	30,313,238
2019	9,958,251	(2,182,064)	7,776,187
2020	10,661,010	(9,582,067)	1,078,943
2021	10,725,833	(9,648,294)	1,077,539
2022	10,103,690	(19,781,529)	(9,677,839)
2023	3,387,465	(24,348,070)	(20,960,605)
2024	5,271,465	(21,429,619)	(16,158,155)
2025	18,165,000	(23,300,000)	(5,135,000)

2

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Request IR-46:

(a) Please identify the amount budgeted in proposed rates for OM&G costs for vegetation management in 2026 and 2027.

(b) Please provide a table showing the amount of OM&G funds spent on vegetation management for each year from 2019 to 2024 inclusive. Please separately identify funds related to distribution and transmission.

(c) Please provide similar information to b) regarding capital funds associated with routines and individual work orders.

Response IR-46:

(a) Please refer to the table below.

Year	OM&G (\$ million)
2026	9.6
2027	9.8

(b) Please refer to the table below.

Year	Distribution (\$ million)	Transmission (\$ million)	Total (\$ million)
2019	8.0	3.5	11.5
2020	2.5	1.7	4.2
2021	2.0	2.3	4.2
2022	2.5	2.4	4.9
2023	7.5	3.0	10.5
2024	3.1	5.7	8.8

(c) Please refer to Attachment 1.

2026-2027 GRA NSEB IR-46 Attachment 1 has been filed electronically.

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Request IR-47:

**Reference: Exhibit N-3 GRA Direct Evidence, Section 1.5.6 NSEISO Transition, p.75,
Exhibit N-6 Appendix 7A**

(a) Please provide a breakdown of the \$1.6 million in costs removed from NS Power's revenue requirement for 2026 and \$4.5 million in 2027, due to the transition of some current NS Power responsibilities to the Nova Scotia Independent Energy System Operator.

(b) What is NS Power's current assessment of the likelihood that the phase one transition will occur on January 1, 2026, and the phase two transition on January 1, 2027?

Response IR-47:

(a) Breakdowns of the \$1.6 million in costs removed from NS Power's revenue requirement for 2026 and \$4.5 million in 2027 are as follows:

	2026
Labour for 22 employees	1,540,196
Travel	12,760
Membership Dues	6,120
Telephones	5,429
Training	4,090
Personal Protective Equipment	1,538
Total	1,570,132

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	2027
Labour for 38 employees	4,444,787
Training	39,125
Travel	31,213
Telephones	19,009
Membership Dues	4,680
Personal Protective Equipment	994
Total	4,539,807

- 1
2
3 (b) There remain a number of issues to be resolved before the transition can occur, including
4 completion of compliance related registrations, finalization of people transfer and
5 operational arrangements, and continued coordination among the parties. The parties are
6 continuing to work collaboratively toward achieving an orderly transition. While
7 assumptions have been made using January 1, 2026, and January 1, 2027, as potential target
8 dates for phase one and phase two respectively, the timing remains uncertain and will
9 depend on the resolution of several developing factors that could affect readiness.

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Request IR-48:

Reference: Exhibit N-3 GRA Direct Evidence, Figure 7-1 – Five-Year Operating Cost Forecast.

Please update the five-year forecast from NS Power’s last general rate application (reproduced below) to include actuals and percentage variance from forecast to actual for the period:

Figure 6-4: 2022-2026 Operating Cost Forecast

	2022	2023	2024	2025	2026
Operating costs (\$ million)	283.6	288.8	297.4	316.2	321.6
Increase (\$ million)		5.2	8.6	18.7	5.5
Percent Change		1.8	3.0	6.3	1.7

Response IR-48:

Please see the table below:

	2022	2023	2024
Operating Costs (\$ million)	279.8	325.7 ¹	328.5
Increase (\$ million)		45.9	2.8
Percent Change		16.4%	0.9%
Forecast Operating Costs (\$ million)	283.6	288.8	297.4
Percentage Variance to Forecast	-1.3%	12.8%	10.5%

¹ Includes approximately \$21.8 million that was deferred and is being recovered through the 2025 Storm Cost Recovery Rider (SCRR).

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Request IR-49:

Reference: Exhibit N-3 GRA Direct Evidence, Section 1.1 Support for 2026-2027 GRA

On page 9, NS Power stated that “...the process that has been undertaken to develop this GRA has been extensive” and “Indeed, this collaborative outcome includes reduced costs to account for the anticipated GRA-related regulatory efficiencies that have been created by the parties’ collaborative efforts and work.”

(a) How much is the cost reduction referenced above?

(b) Please provide a breakdown of the actual and forecast regulatory costs for each of 2020 to 2030 inclusive. That breakdown should further identify the internal NS Power GRA-related costs and the external GRA-related costs.

Response IR-49:

(a) NS Power reduced the forecast amortization of external costs associated with the 2026-2027 GRA from \$4 million to \$2 million due to anticipated GRA-related regulatory efficiencies of achieving a settlement agreement with customer representatives in advance of filing the GRA.

(b) Please see the table below:

Year	Regulatory Affairs Expense (\$ million)	GRA and COSS Costs (\$ million)
2020	7.3	-
2021	6.0	-
2022	11.7	3.7
2023	7.5	0.3
2024	9.4	0.5
2025F	9.3	1.5
2026F	9.5	-
2027F	9.7	-

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Year	Regulatory Affairs Expense (\$ million)	GRA and COSS Costs (\$ million)
2028F	9.9	-
2029F	10.1	-
2030F	10.3	-

1
2 All GRA and Cost of Service Study costs are external and incremental costs. NS Power
3 does not track internal GRA costs. Please note that \$0.8M of GRA expense was incurred
4 in 2021 but was expensed in 2022 as NS Power had initially proposed to defer and amortize
5 costs associated with its previous GRA. Costs associated with the 2023-2024 GRA are
6 included in OM&G expense in the years 2021-2023. Costs associated with the 2026-2027
7 GRA are not included in the 2024-2026 OM&G expense figures (i.e. are not included in
8 the totals of \$9.4 million and \$9.3 million), consistent with NS Power's request to defer
9 and amortize these costs over the 2026-2027 test period.

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1 **Request IR-50:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 7.3 Five-Year Operating Cost**
4 **Forecast.**

5
6 **On page 36, NS Power stated that “The consensus approach to this GRA results in a greater**
7 **year-over-year increase from 2027 to 2028.” Figure 7-1 shows an increase of \$6.1 million**
8 **from 2026 to 2027 and \$22.1 million from 2027 to 2028.**

9
10 **(a) Please explain this statement.**

11
12 **(b) What is the variance from the 2025 forecast to the 2026 forecast?**

13
14 **(c) Please itemize the components and their contributions to the forecast \$16 million**
15 **increase from 2027 to 2028.**

16
17 **(d) Please explain the forecast \$2.5 million reduction in operating costs from 2029 to 2030.**

18
19 **Response IR-50:**

20
21 **(a) NS Power forecast 2028 OM&G expense by escalating costs at inflationary rates from the**
22 **2027 forecast, prior to the OM&G reduction agreed to per the consensus agreement with**
23 **customer representatives and adjusted for any other expected changes to operating expense.**
24 **Building inflationary increases for 2028 on the 2027 forecast and subsequently decreasing**
25 **the 2027 forecast has resulted in a larger percentage increase in forecast operating expense**
26 **from 2027 to 2028.**

27
28 **(b) NS Power forecasts OM&G expense of \$343.7 million in 2025 and \$351.8 million in 2026,**
29 **an increase of \$8.1 million.**

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- (c) NS Power understands this question to be referring to the \$22 million increase in OM&G expense from 2027 to 2028 as opposed to \$16 million as stated in the question. Please see the table below:

Component	Contribution (\$ millions)
Reduction to 2027 OM&G per Consensus Agreement	9.0
Inflation	7.3
Increased Pension Expense	2.2
Increased Corporate Expense (IT and Insurance)	1.7
Decreased Administrative Overhead	1.7
Total	22.1

- (d) The decreased OM&G forecast in 2030 as compared to 2029 is primarily due to a forecast reduction of \$25.5 million in the Thermal Plants operating group due to the anticipated retirement of certain plants and facilities partially offset by reduced administrative overhead and inflationary increases across other operating groups. The plants and facilities that are forecast to be retired at the end of 2029 are consistent with the assets that are currently expected to be within the scope of the Decarbonization Deferral Account.

REDACTED

1 **Request IR-51:**

2
3 **Reference: Exhibit N-6, Appendix 7A.**

4
5 **Please explain the basis for the labour inflation rates noted on page 6 in Appendix 7A.**

6
7 Response IR-51:

8
9 The labour inflation rates for union employees were determined using the current ratified collective
10 agreement, which provided a 4 percent increase on April 1, 2025 and expires on March 31, 2026,
11 and research provided by the Company's compensation consultant, Mercer, resulting in a [REDACTED]
12 [REDACTED] on April 1, 2026 and April 1, 2027. The Company's compensation consultant considered
13 select economic indicators including unemployment rate, real GDP growth, and inflation rates,
14 including both historical and forecast data from a number of reputable sources (i.e., Bank of
15 Canada, and major Canadian banks). Mercer recommended an average Atlantic salary [REDACTED]
16 [REDACTED] for 2026 to 2027.

17 NS Power assumes that the labour inflation rates will be the same as for union and non-union
18 employees. The [REDACTED] in 2026 recognizes the assumption that wages will be [REDACTED]
19 [REDACTED] in the first quarter of 2026 due to the timing of the [REDACTED] on April
20 1, 2025.

NON-CONFIDENTIAL

1 **Request IR-52:**

2
3 **Reference: Exhibit N-6, Appendix 7A**

4
5 **Please confirm, or explain otherwise, that the primary driver of the primary drivers on**
6 **increased actual operating expenses noted on page 7 in Appendix 7A was the delay of the**
7 **Nova Scotia Block.**

8
9 Response IR-52:

10
11 Not confirmed. NS Power received a greater amount of NS Block energy in 2024 than was
12 included in the 2024 GRA budget. NS Power received 1,378 GWh of NS Block energy in 2024 as
13 compared to 1,134 GWh that was included in the 2024 GRA budget, due to NS Block make up
14 energy from lower 2022-2023 delivery of NS Block energy. Increased thermal unit utilization in
15 2024 was primarily due to reduced imports due to lower surplus energy availability over the
16 Maritime Link and lower import energy availability from New Brunswick. In addition, there was
17 decreased renewable generation by NS Power and independent power producers and increased
18 system requirement.

19
20 NS Power forecast retiring Trenton Unit 5 and Lingan Unit 2 during the 2023-2024 test period but
21 now expects to require these units until 2028 and 2029, respectively, due to system load and
22 capacity requirements.

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1 **Request IR-53:**

3 **Reference: Exhibit N-6, Appendix 7A**

5 **Please explain the reason for the increased regulatory requirements for fuel system**
6 **equipment inspections at Tufts Cove, noted on page 8 in Appendix 7A.**

8 Response IR-53:

10 The increased regulatory inspections for fuel system equipment inspections at Tufts Cove are
11 driven by a combination of factors, including asset age, condition, and compliance obligations
12 under the Nova Scotia Petroleum Management Regulations and associated Industrial Approvals
13 issued by the Nova Scotia Department of Environment and Climate Change. As fuel system assets
14 age, their condition may deteriorate, triggering more frequent or detailed inspections to ensure
15 continued safe operation and environmental protection.

17 NS Power's Petroleum Piping and Tank Inspection and Integrity Program (Quality Processes QP-
18 G011 and QP-G039) outlines a risk-based approach to inspection planning. This program includes
19 daily visual inspections, periodic external in-service inspections (typically every five years), and
20 internal out-of-service inspections (up to every 20 years), all informed by Risk-Based Assessments
21 (RBA). These assessments evaluate asset condition, degradation mechanisms, and criticality, and
22 are used to determine appropriate inspection intervals and scope. As specific assets at Tufts Cove
23 reach inspection milestones or exhibit signs of wear, the RBA process may recommend increased
24 inspection frequency or additional testing to maintain compliance and mitigate risk.

26 The forecast inspection costs during the GRA period reflect the planned execution of inspections
27 for assets identified as due through the RBA process. These inspections are essential to meet
28 regulatory requirements and to ensure the integrity of fuel system equipment, particularly given
29 the critical role of Tufts Cove in supporting system reliability and integrating intermittent
30 renewable generation.

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1 **Request IR-54:**

2
3 **Reference: Exhibit N-6 Appendix 7A**

4
5 **Regarding s. 1.5.7 (Cost Savings Initiatives), please identify any initiative or pilot projects**
6 **NS Power plans to undertake in 2026 and 2027 to identify or assess new cost savings**
7 **initiatives or processes to increase efficiencies and reduce costs for customers.**

8
9 Response IR-54:

10
11 In addition to the numerous initiatives identified in s. 1.5.7, which will continue throughout the
12 2026-2027 period, the entire GRA process is a cost-saving initiative for the years 2026 and 2027.
13 In preparing its revenue requirement forecast, NS Power challenges each business unit to identify
14 and find cost savings. Through the collaborative process with customer representatives that
15 resulted in this consensus GRA, NS Power agreed to reduce its O&M costs further, which
16 represents a further initiative within the business to find these savings (Please see NSEB IR-1).

17
18 Of course, these initiatives are in addition to the work NS Power has done on behalf of customers
19 in relation to the purchase of the \$117 million receivable by Invest Nova Scotia, the \$500 million
20 FLG, the adjustment to sulphur emission regulations (resulting in approximately \$160 million in
21 savings for customers), and the proposed securitization of approximately \$704 million in rate base,
22 all of which were identified, pursued, and achieved as a result of NS Power's persistent efforts on
23 behalf of customers.

24
25 Further examples of where NS Power has created significant value for customers by working with
26 stakeholders such as the Provincial and Federal Government to reduce costs and rate pressure for
27 customers, include the following:

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- NS Power has created significant forecast savings described in M11539 Battery Energy Storage System. NS Power negotiated beneficial financing and securing federal grant funding through the SREP program reducing costs by a combined \$131 million.
- NS Power has created significant forecast savings described in M12217 NS-NB Reliability Intertie Project. NS Power established the Wasoqonatl Transmission Incorporated financing structure with low-cost CIB equity creating an expected \$200 million in NPV cost savings.

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Request IR-55:

Reference: Exhibit N-6 Appendix 7A, Figure 7A-10 2020-2024 Storm Restoration Operating Expenses.

(a) Please explain why the approved deferred recovery of Post Tropical Storm Fiona costs makes it inappropriate to include these costs for a more complete picture of storm costs actually incurred in the period covered by Figure 7A.

(b) Please restate Figure 7A to include these costs.

Response IR-55:

(a) NS Power is not of the opinion that the approved deferred recovery of Post Tropical Storm Fiona costs makes it inappropriate to include these costs when illustrating a complete picture of storm costs for the 2020-2024 period. The intent of Figure 7A-10- 2020-2024 Storm Restoration Operating Expenses was to show the calculation of NS Power's proposed storm Level 3 and 4 OM&G expense using prior period OM&G expense as the starting point in this calculation. As Hurricane Fiona storm recovery costs are not included in NS Power's prior period OM&G expense, these costs were omitted.

(b) Please see the table below:

(\$ million)	2020	2021	2022	2023	2024	2020-2024 Average
Level 1-2	9.5	7.2	6.2	12.0	9.0	8.8
Level 3-4 (including Hurricane Fiona)	9.1	1.4	39.3	32.1	3.7	17.1
less: Hurricane Fiona	-	-	-24.4	0.0	-	-4.9
less: Post Tropical Storm Lee	-	-	-	-14.2	-0.3	-2.9
Adjusted Level 3-4	9.1	1.4	14.9	17.9	3.4	9.3
Total	18.5	8.6	21.1	29.9	12.4	18.1

NON-CONFIDENTIAL

1 **Request IR-56:**

2
3 **Reference: Exhibit N-6 Appendix 7A**

4
5 **On page 27 of Appendix 7A, NS Power advises it has increased expense in Grid**
6 **Modernization and Customer Integration to hire seven additional employees on the**
7 **Customer Experience team for continued expansion of services and product offerings and**
8 **customer support with focus on awareness, education, and adoption for customers and an**
9 **additional four employees to focus on data analytics to provide asset management insights to**
10 **further enhance NS Power's asset management capabilities and improve capital investment**
11 **decision-making and expand customer rate offerings.**

12
13 **(a) Please describe the new services and product offerings that NS Power intends to**
14 **introduce in 2026 and 2027.**

15
16 **(b) Please confirm, or explain otherwise, that NS Power's ability to expand customer rate**
17 **offerings is limited by its outdated Customer Information System, which NS Power**
18 **does not expect to be launched until sometime in 2029 (see Matter M11884).**

19
20
21 **Response IR-56:**

22
23 **(a) The incremental labour supports the maintenance and enhancement of the expanding**
24 **portfolio of digital solutions such as Green Button, Provincial Community Solar, My**
25 **Energy Insights, Rate Offerings (including expanding the Time-varying Pricing pilot) and**
26 **the customer-facing website. Customer, grid asset, and AMI data is used to assess and**
27 **design customer programs and subsequently evaluate, measure, and validate program**
28 **performance. The impact that customer programs have on how and where energy is**
29 **consumed on the grid is an input to distribution asset management planning. In addition to**
30 **the expanded digital channel and rate offering support, NS Power is delivering a Customer**

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1 First, role-specific training program to educate employees in delivering a positive
2 customer experience. NS Power is expanding its communication initiatives with customers
3 across a variety of mediums and in-person engagements such as home shows to ensure
4 customers have access to information and expertise in managing their energy needs.
5

6 (b) The NS Power August 29, 2025 filing in M11884 outlined NS Power's Customer
7 Information System (CIS) Project Summary and Timeline. NS Power anticipates the scope
8 of the CIS Replacement project would include enhancements to enable new customer
9 offerings and tariff designs in the future. The work in 2026 and 2027 does not require a
10 new CIS system but will be further enhanced by modernizing the Company's CIS in the
11 future.

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1 **Request IR-57:**

2
3 **Reference: Exhibit N-6, Appendix 7E, Executive Compensation Report**

4 **(a) Please confirm, or explain otherwise, that the “pay plan” referenced in the *Nova***
5 ***Scotia Power Incorporated Regulations* is defined as “the Senior Officials Pay Plan**
6 **approved by the Governor in Council by Order in Council 2007-85 under the *Civil***
7 ***Service Act* and the *Public Service Act*, and as amended from time to time.”**

8
9 **(b) Please confirm, or explain otherwise, the “pay plan” referenced in the *Nova Scotia***
10 ***Power Incorporated Regulations* was not amended but revoked by Order in Council**
11 **2023-138.**

12
13 **(c) Please explain how NS Power determined the amounts recoverable through rates in**
14 **Appendix 7E if the pay plan used as the benchmark was revoked.**

15
16 **(d) Please confirm, or explain otherwise that the new Senior Officials Pay Plan approved**
17 **by Order in Council 2023-138 is materially different from the revoked version**
18 **referenced in the *Nova Scotia Power Incorporated Regulations* in that it: (i) includes a**
19 **number of additional pay scales; (ii) no longer references a single pay scale applicable**
20 **to deputy ministers; (iii) no longer includes any pay scales that provide for a salary**
21 **based on a 110% compa ratio.**

22
23 **(e) Please provide details of any discussions between any representative of NS Power any**
24 **government official about the revocation of the pay play referenced in the *Nova Scotia***
25 ***Power Incorporated Regulations*.**

26
27 **(f) Please provide copies of any written communications between any representative of**
28 **NS Power and any government official about the revocation of the pay plan**
29 **referenced in the *Nova Scotia Power Incorporated Regulations*.**

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1 Response IR-57:

2
3 (a) Confirmed.

4
5 (b) Not confirmed. The Senior Officials Pay Plan was amended in its entirety, thereby
6 resulting in the revocation or repeal of the prior plan.

7
8 (c) NS Power used the Senior Officials Pay Plan as amended and determined the amounts
9 recoverable through rates by using the higher of the published pay scales, in the same
10 manner it has in previous GRAs. It then calculated a 110 percent compa ratio.

11
12 (d) NS Power acknowledges that OIC 2023-138 amended the pay plan such that there are
13 differences between the existing and prior versions.

14
15 (e–f) NS Power has had no discussions or communications with any government official
16 regarding OIC 2023-138 or its effect.

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Request IR-58:

Reference: Exhibit N-6, Appendix 7A, page 7 of 37.

NS Power notes a significant increase in the utilization of thermal plants and combustion turbines, which was 4,525 GWh estimated capacity and 6,148 GWh used capacity, appears to be one of the primary drivers for operating expense increase in 2024.

(a) Please explain the cause of this scenario and NS Power's plans to mitigate similar issues to lower operating expense.

(b) Please indicate if NS Power expects similar expense levels in 2025, 2026 and 2027, and identify the amount budgeted in proposed rates.

Response IR-58:

(a) Increased thermal unit utilization in 2024 was primarily due to reduced imports due to lower surplus energy availability over the Maritime Link and lower import energy availability from New Brunswick. In addition, there was decreased renewable generation by NS Power and independent power producers and increased system requirement.

(b) NS Power expects similar levels of operating expense in 2025–2027, although the drivers of those expenses differ from those in 2024. In 2025–2027, while overall thermal generation is forecast to decline, NS Power anticipates sustained or increased unit cycling and flexible operation to support the integration of new renewable resources and battery storage.

As described in GRA NSEB IR-75, flexible operation involves frequent start-ups, shutdowns, and operation at partial or lower loads to accommodate variable renewable

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1 energy. These operating modes increase wear and tear, reduce thermal efficiency, and
2 elevate fuel and chemistry costs—particularly during start-up phases.

3
4 Therefore, although total operating hours may decline, the intensity and variability of
5 operation are expected to maintain OM&G expenses at levels comparable to 2024. This
6 dynamic reflects the evolving role of thermal assets in a more flexible, renewable-
7 integrated grid.

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Request IR-59:

Reference: Exhibit N-6, Appendix 7A, Figure 7A-10, page 22 of 37

NS Power provided the storm restoration operating expenses for years 2020 to 2024.

a) The table indicates a much lower operating expense in 2021 and 2024.

i. Please explain any activities NS Power performed to lower operating expense in these two years.

ii. Please update the table with the number of Level 1-2 and Level 3-4 storms for each year from 2020 to 2024.

b) In M12071 Storm Outage Analysis Report -December 12, 2024, NS Power provided a response to the Board's IR-10 e):

NS Power is implementing higher-strength insulator designs and improved installation techniques in areas prone to high winds. This includes transitioning to insulator types with enhanced mechanical performance and evaluating new installation methods to ensure greater resilience against wind-related stress.

i. Please provide the research and activities NS Power performed on grid resilience improvement against wind-related stress.

Response IR-59:

(a)

i. NS Power continuously improves after every storm and as indicated in the IR responses to the 2024 Storm Rider filing, NS Power has implemented a number of cost improvement activities for Level 3 and 4 storms, however since the beginning of 2024, there has only been one Level 3 storm but the response ended up being less than that due to the actual weather experienced. The cost of responding to a storm event varies based on the specific conditions faced by NS Power, even within

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the same level of storm band. The difference in operating expense in 2021 and 2024 is largely a function of the lower number of level 3-4 storms in each of those years. Those two years were characterized by only a single level 3 EOC activation and the remaining storm events categorized as level 1-2. The operating spend differences of these years are a result of the lower spend responding to a single level 3 event, compared with 3, 8, and 6 level 3-4 storms in 2020, 2022, and 2023 respectively.

ii.

Year	2020	2021	2022	2023	2024
Level 1-2 Storms	4	4	3	1	7
Level 3-4 Storms	3	1	8	6	1

(b)

- i. NS Power Standards engineers participate in the CSA technical committee for Overhead Systems (C22.3 No. 1). Since 2016, climate scientists with the CSA have collected weather data across Canada and built models for projecting changes to this weather data up to the year 2090. These changes are based on a projected average global temperature increase of 2.0 degrees Celsius over a 60-year period, followed by an additional 0.5 degrees Celsius temperature increase in the following 10 years, after which the global temperature increase is expected to level off. The CSA Overhead Systems standard (C22.3 No. 1) provides weather data and conditions for which all overhead power and communications systems must be designed to withstand. This includes wind speeds for 25 locations across Nova Scotia. In this standard, wind speeds for the 50-year return period (a 2 percent probability of occurrence annually) are provided along with the future wind projections based on 2 degrees Celsius and 2.5 degrees Celsius of global warming. These projected wind speeds have been used in the wood pole models which were

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1 built for developing the new pole class standard, resulting in stronger poles as the
2 standard for Nova Scotia.

3 In addition to increasing the size and strength of wood poles, Nova Scotia Power
4 has increased the usage of clamp top insulators. A power wire is secured to a
5 traditional polymer insulator using a ‘tie wire’, a short piece of high strength
6 aluminum wire wrapped around the conductor in a fashion that secures it at the
7 correct angle against the insulator. An alternative to the traditional insulator and tie
8 wire is a clamp top insulator, which uses a built-in clamp device to secure the wire.
9 In excessive wind speeds, vibrations can occur in the power conductor that may
10 cause the tie wire to break. Clamp top insulators have higher strength in the clamp
11 mechanism that secures the conductor to the insulator. As a result, they are less
12 prone to breakage in extreme wind conditions. These insulators were first deployed
13 in the highest wind regions of Nova Scotia (Cheticamp and along the Cabot Trail)
14 and proved to be very resilient in extreme winds. As a result, these insulators have
15 been more widely deployed across Nova Scotia in recent years, with a focus on
16 deploying these insulators in regions with projected future wind speeds exceeding
17 110km/h.

REDACTED

Request IR-60:

Reference: Exhibit N-6(ii), Corporate Office of Secretary and General Counsel

With respect to the reasons given for the following significant projected increases for 2026 over 2024 actuals:

(a) Consulting and Ext Legal & Audit

(i) While it is understood that the CRA litigation is ongoing, please explain the reasons for the year over year increases in costs for consulting, travel, contracts, and external legal audit.

(ii) As noted by NS Power on page 54 of its application, it filed an appeal in the Tax Court of Canada six years ago, on November 19, 2019. Please explain the reasons for the delay in having this matter heard and indicate if a hearing date has been set and when the matter is likely to be resolved.

(iii) What are the total costs related to the CRA appeal in these areas and all other expense categories incurred to date? (i.e. including the additional FTE noted in M10431 Board IR-38(a))

(iv) What is an estimate of the remaining costs related to the litigation that will be required up to the point where a decision is rendered?

(v) Has NS Power done a cost/benefit analysis with respect to the benefits of earlier deduction of the disputed costs versus the cost of the litigation?

a. If so, please provide.

b. If not, why not?

(b) Insurance

(i) Please provide additional details and a breakdown for the increases in insurance premiums.

(ii) Has NS Power sought quotes for 2026? If not, what is the forecast based on?

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1 Response IR-60:

2
3 (a) Consulting and External Legal & Audit

4
5 (i) As the CRA matter is ongoing, costs that will take place in the future, are not occurring
6 at the same level in 2024 actual. The year over year increases relate to the fact that as
7 delays in the file continue, costs get pushed out and estimates are made for inflation.

8
9 The forecast for External Legal costs are reflective of the currently anticipated stages
10 of the litigation. The 2025 budget and 2026-2027 forecast anticipate a substantial
11 increase in activity in the litigation associated with a “ramp up” to trial (*ie* trial
12 preparation and trial).

13 (ii) Since the appeal was filed, Tax Court of Canada has experienced a significant backlog
14 as a result of lack of resources (including Judges) and COVID closures. This backlog,
15 coupled with the fact that the parties are currently waiting for decisions in discovery
16 motions that were heard in January 2025 are the reason for the delay in having the
17 appeal heard. The outcome of the discovery motions will impact the process and timing
18 of the balance of the litigation.

19 No hearing date has been set for the litigation. It is currently unknown when the matter
20 is likely to resolve.

21 (iii) The total costs incurred to date on the CRA appeal is [REDACTED]

22
23 (iv) As stated in part (a, ii), the timing for next steps in the litigation is currently unknown
24 and the process and scope of those steps will be impacted by matters outside of NS
25 Power’s control (including the outcome of the discovery motions). As a result, NS
26 Power cannot provide an estimate of the costs through to a decision being rendered at
27 this time.
28

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1 (v) At all times, NS Power's analysis and decision-making is guided by the best interests
2 of customers. The cumulative net amount in dispute to date is \$126 million. Any
3 analysis prepared by NS Power and/or its counsel with respect to the litigation
4 (including potential outcomes) is subject to solicitor-client and/or litigation privilege
5 and cannot be disclosed.

6 (b) Insurance
7

8 (i) A list of insurance premiums for 2025 is provided in GT IR-09. This reflects the
9 Company's recent experience in obtaining insurance coverage and forecast for the test
10 period and is reflective of the benefits NS Power achieves on behalf of customers as a
11 result of being part of the larger Emera insurance portfolio.
12

13 (ii) The forecast is based on quotes for the 2025 budget and are given escalators by NS
14 Power's brokers for estimates on what insurance premiums will be for the test years.

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1 **Request IR-61:**

2
3 **Reference: Exhibit N-6(ii), Communications and Public Affairs**

4
5 **(a) The reason given for the increase from 2024 actuals to forecast 2026 expense in labour**
6 **expense under Communications and Public Affairs is the same as many other**
7 **categories stating it is due to staff complement change and salary escalations. The**
8 **increase in this category in 2026 over 2024 actuals is 48%, and over 100% compared**
9 **to the 2024 compliance filing. Please explain why there is a more significant increase**
10 **in this labour category than in others.**

11
12 **(b) Similarly, the consulting expense forecast for 2026 has increased over 400% from the**
13 **2024 compliance filing. Please explain why such a significant increase has been**
14 **required in the last two years.**

15
16 **(c) Please provide additional details about the advertising increases and the planned**
17 **engagements for Customer Communications, including whether new initiatives have**
18 **been undertaken or are planned for the test years.**

19
20 **(d) Please confirm that no part of the increases (a) or (b) are related to the cybersecurity**
21 **breach or its aftermath in the test years.**

22
23 **Response IR-61:**

24
25 **(a) The increase of \$0.9 million for labour since 2024 compliance and \$0.6 million since 2024**
26 **actual to 2026 Budget is due to the addition of Communication and External Engagement**
27 **employees that perform tasks that previously weren't undertaken.**

28
29 External Engagement is a new department that was not included in the 2024 Compliance
30 forecast. The department is focused on increasing engagement with stakeholders and

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1 communities across the province to receive input and feedback, and to share more
2 information on priorities, projects and initiatives undertaken by the utility in response to
3 customer and stakeholder feedback. Through more engagements such as community
4 meetings and open houses, NS Power can gather feedback that can be incorporated into
5 plans for work in the community. For example, these engagements may provide
6 community and/or stakeholder updates on capital projects such as hydro work and
7 reliability-focused upgrades or sharing information on Nova Scotia Power's Five-year
8 Reliability Plan, as well as major projects as part of the Eastern Clean Energy Initiative.

9
10 In addition, in the Communications and Public Affairs department, there has been an
11 increased focus on finding new ways to reach out to customers to provide more
12 information. This would include such items as alternative rate offerings from NS Power,
13 updates on reliability investments and planned outages, as well as information to help
14 customers prepare for winter heating season to try to help ease concerns or questions about
15 billing. NS Power has also brought more marketing and graphic design in-house as opposed
16 to contracted work. This shift has reduced costs associated with contracting this work, and
17 feedback from customers shows that the content being produced internally has been
18 received favorably (as measured by engagement metrics).

19
20 (b) The increase of \$0.7 million for consulting as compared to 2024 Compliance forecast is
21 related to an increased focus on research and engagement with customers to improve the
22 information and content that they receive from NS Power. The Company engaged external
23 consultants to further improve the ability to provide information that is sought after by
24 customers and ensure NS Power is reaching customers in the most effective way possible.
25 Consulting expense in 2026 will include the development of increasingly customized
26 and targeted content for customers and the continuation of customer feedback surveys to
27 understand if these methods continue to be effective.

28
29 (c) For the previous ten years, NS Power relied on traditional media, and later social media, to
30 communicate with and provide messaging to customers. With the changing media

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1 landscape, NS Power is finding it necessary to find more ways to reach customers with
2 information they need on key topics such as safety, affordability/value, storm response and
3 reliability improvements. The advertising expense is to incorporate different content
4 channels to reach customers in the most effective way possible and thus, is spread over
5 many different channels. Engaging with customers in person is another important
6 component of this work, with advertising required to notify customers of upcoming
7 opportunities to engage with Nova Scotia Power staff in person. These new initiatives have
8 begun and will continue to take place over the GRA test period, with ongoing measurement
9 of these initiatives to confirm effectiveness and identify the need for new approaches.

- 10
- 11 (d) Confirmed. NS Power developed the forecast for the test period in advance of the cyber
12 security incident and there are no costs associated with the cyber security, or its aftermath,
13 included in the test period forecast.

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Request IR-62:

Reference: Exhibit N-6(ii), Corporate Human Resources

(a) The reason given for the increase from 2024 compliance restated to forecast 2026 expense in labour under Human Resources is due to staffing level increase and salary escalation. This is an increase of 58%. Please explain why such a significant increase is required in Human Resources.

(b) The increase in consulting expense is similarly high at 47% over 2024 compliance and 114% over 2024 actuals.

(i) Please explain why such a significant increase is required in consulting given the additional internal staff in this area. Could this work have been done internally? If not, why not?

(ii) NS Power notes the increase is partly due to increased safety programs. The increase holds steady through 2027. Are these safety programs expected to take place over two years? Please provide further information on the safety and health and wellness programs.

(c) Please provide additional details about the allocation of costs for talent management.

(d) Please comment on the cost increases noted above from 2024 to 2026, in light of the observations in the ScottMadden Report (OP-03, Attachment 1, Pages 64-68 of 87) that suggest, based on five years of data up to 2023, that NS Power is already above average for human resources costs compared to its peers.

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1 Response IR-62:

2
3 (a) The increase of \$2.3 million for labour from the 2024 Compliance forecast is primarily due
4 to additional resources in the Safety department to focus on further reducing serious injury
5 frequency and enhancing contractor safety management. This is required due to the
6 increased number of NS Power employees and significant growth in customer-requested
7 work. In addition, NS Power has added additional employees to attract skilled employees
8 and support Diversity, Equity and Inclusion programs. The difference of \$0.8 million from
9 2024 actual to 2026 GRA forecast is related to additional Safety department staff and
10 labour cost escalations.

11
12 (b)

13 (i) The increase of \$0.3 million for consulting since 2024 compliance and \$0.5 million
14 since 2024 actual is driven by the overall increase to total company headcount,
15 which increases the support required by the Human Resources and Safety teams.
16 The primary driver of the increase is increased medical consulting expense. NS
17 Power has determined that it is more economic to purchase these services from a
18 third-party as opposed to performing the work internally.

19
20 (ii) As NS Power continues to focus on safety by further reducing serious injury
21 frequency and enhancing contractor safety management, these types of programs
22 are expected to be ongoing as NS Power has determined it is more economic to
23 purchase these services from a third-party than performing the work internally.

24
25 (c) Talent Management is handled by NS Power's Parent company Emera and costs are
26 allocated to NS Power in accordance with the Board-approved Affiliate Code of Conduct
27 and Cost Allocation Manual. The centralization of these functions allows for cost savings,
28 rather than using separate departments at each affiliate. The difference compared to 2024
29 Actual is primarily due to increased staffing levels at NS Power, driving an increase in the
30 utilization of Talent Management services from Emera and cost allocation to NS Power.

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1 (d) As noted by NS Power in its direct evidence, comparing electric utilities in different
2 Canadian and American jurisdictions can be difficult and has its limitations, because of the
3 differences in company structure, ownership, customer base, asset base, operating
4 geographies and size. For example, other utilities may embed some Human Resources
5 functions in operating and other corporate groups as opposed to centralizing the functions
6 in a Human Resources department or may be of a larger size, improving the economies of
7 scale to offer Human Resources programs on a per employee basis.

8
9 NS Power continually evaluates the required Human Resources complement and programs
10 that are required, to provide customers with improved value. In addition, the Company
11 evaluates whether services are more economic to provide with internal staff or outsourced
12 to a third party and operates on a shared service model for some Human Resources and
13 Safety functions to improve economies of scale.

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1 **Request IR-63:**

2
3 **Reference: Exhibit N-6(ii), Regulatory Affairs**

4
5 **The consulting expense forecast for 2026 is 57% higher than 2024 compliance and slightly**
6 **below 2024 actuals. Board staff assumes that much of the work leading into the GRA would**
7 **have been completed, or at least commenced, in 2024 (i.e. the depreciation study, the line loss**
8 **study, the cost of service study).**

9
10 **(a) Given this level of pre-GRA work occurring in 2024, please explain why the expense**
11 **is expected to stay at this level? Specifically, what regulatory engagements in 2026**
12 **and 2027 are expected to result in a “greater volume and scope” of regulatory work**
13 **in these years?**

14
15 **Response IR-63:**

16
17 **(a)** While GRA pre-work began in 2024, the majority of incremental cost associated with the
18 2026-2027 GRA is expected to be incurred in 2025. In addition, the incremental GRA
19 expense is not reflected in the Regulatory Affairs operating expense as this expense is
20 currently being deferred pending NS Power’s proposal to expense the forecast incremental
21 cost over the two-year test period as illustrated in NS Power’s Direct Evidence, Figure 8-3
22 – 2026-2027 Regulatory Amortizations. NS Power has not included costs associated with
23 a GRA in future year forecasts, consistent with the Company’s proposal to amortize these
24 costs over the test period. As a result, the increased Regulatory Affairs consulting expense
25 as compared to the 2024 GRA Compliance budget is associated with the greater volume
26 and scope of regulatory affairs activity in proceedings other than the GRA and Cost of
27 Service Study. Furthermore, NS Power is increasingly being relied upon to carry out
28 specialized tariff and rate work and modelling for specific customers or industries. It is
29 anticipated that such work will continue throughout the test period.

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1 **Request IR-64:**

2
3 **Reference: Exhibit N-3 Direct Evidence, Exhibit N-6(ii), Information Technology**

4
5 **Pages 8-9 in the direct evidence notes that the test year forecasts were completed before the**
6 **cybersecurity incident occurred, and that the forecasts were not updated to reflect any**
7 **increases after the incident. The consulting expense in Information Technology has an over**
8 **1000% increase over the 2024 compliance restated. The explanation given for the increase is**
9 **that it is due to support for the cybersecurity program and incremental expenses for**
10 **continued improvements to Tableau and PowerBI.**

11
12 **(a) Please further explain the drastic increase in information technology consulting**
13 **expense that has occurred since the previous rate case. Did this increased level of**
14 **spending in any way mitigate the damage from the cybersecurity incident?**

15
16 **(b) Board staff notes that the actual consulting expense incurred in 2024 is in line with**
17 **the forecast for 2026 and 2027. Will this level of expense be required annually on an**
18 **ongoing basis? Or is this increase related to one-time costs for implementation of new**
19 **programs or projects?**

20
21 **(c) What are Tableau and PowerBI?**

22
23 **(d) Please provide the Matter number reference for any Board capital work order**
24 **matters related to Tableau and PowerBI.**

25
26 **Response IR-64:**

27
28 **(a) The Nova Scotia Power (NSP) Cyber Security Program was formalized in March 2022**
29 **where NS Power chose a strategic cyber partner to assist with cyber strategy, roadmap, and**
30 **workplan development. The majority of the cyber security consultant spend**

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1 (approximately 85 percent) is with NSP's cyber security strategic partner, assisting NS
2 Power with its cyber strategy, roadmap, and annual workplan. This partner also plays a key
3 role in the project management, execution, and delivery of several cyber security projects
4 within the annual workplan. Prior to 2024, the workplan primarily included cyber security
5 for the IT environment. For 2024 onward, the workplan included execution and delivery
6 of both IT and OT, thus an increase in consultant costs for strategy, roadmap, workplan
7 and IT/OT project execution / delivery to meet NS Power's integrated IT/OT cyber security
8 workplan objectives.

9
10 Yes, the additional consulting spending helped mitigate damage from, and improved NS
11 Power's ability to respond to the cybersecurity incident. The annual project spend is
12 required to support the continuous advancement of cyber security capabilities to improve
13 cyber security defences at NS Power. The cyber security strategy, roadmap and workplans
14 are updated annually. The cyber security projects are various projects that work together
15 over time to lower the cyber risk for both NSP's IT and OT environments, implementing
16 new or enhanced cyber security capabilities within each project

17
18 (b) The increased consulting expense is due to the addition of the delivery/execution of the
19 enhanced Operational Technology (OT) Cyber Program in addition to continuing the
20 Information Technology (IT) Cyber Program. This is an ongoing permanent increase to
21 support managing cyber security risk within both IT and OT.

22
23 (c) Tableau and Power BI are both powerful data visualization tools, but they differ in focus
24 and integration. Tableau is known for its advanced visualization capabilities and flexibility,
25 making it ideal for users who need highly customized dashboards and deep data
26 exploration. Power BI, developed by Microsoft, integrates well with other Microsoft
27 products like Excel, offering a more user-friendly interface. While Tableau does well with
28 visual reporting, Power BI stands out for its accessibility and integration within the
29 Microsoft ecosystem.

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- 1 (d) No capital investment related to Tableau or PowerBI has exceeded the materiality threshold
2 of \$1 million that would require a capital application to the NSEB.

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1 **Request IR-65:**

2
3 **Reference: Exhibit N-6(ii), Tufts Cove and Combustion Turbines**

4 **The explanation for the increase in materials expense is that it is due to increased pricing**
5 **and increased running hours.**

6
7 **(a) Why is there such a significant increase in materials expense forecast (particularly**
8 **the 75% over 2024 compliance restated) compared to materials expense in other**
9 **categories?**

10
11 **(b) What is the forecast increase in running hours in 2026 versus 2023, 2024, and 2025?**

12
13 **Response IR-65:**

14
15 **(a)** NS Power's 2023-2024 GRA budget was prepared in 2021. At the time of that forecast,
16 the Company assumed an inflationary rate of 2.7 percent in 2022, 1.9 percent in 2023 and
17 2.0 percent for 2024 when forecasting test period operating expenses. The actual
18 inflationary rate significantly exceeded that forecast. Per the Bank of Canada inflation
19 calculator, the increase in inflation over the 2021 to 2024 period was 4.6 percent on an
20 annual basis. In some cases, materials and contract expenses required for NS Power's
21 operations have significantly exceeded the inflationary rate.

22
23 As per the 10-Year System Outlook, the unit utilization for Tufts Cove is sustained,
24 requiring similar levels of maintenance and as such, more materials. Unit utilization does
25 not just consider running hours, as cycles also drive utilization rates.

26
27 In 2021, the TUC4 and TUC5 Air House project was completed to reduce noise and
28 improve air quality for the engine, thereby extending the asset life. This has resulted in
29 increased cost of materials for the filters for the air house.

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

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(b) Please refer to the table below showing 2023 and 2024 actual operation vs. 2025 and 2026 operation forecasts showing sustained utilization due to unit cycles increasing.

Year	2023	2024	2025	2026
Source	Actuals	Actuals	2024 Q4.4.4	2025 10YRSO
TUC-1 - Hours	5247	6105	3929	448
TUC-1 - Cycles	7	12	12	4
TUC-2 - Hours	5741	5491	5360	1581
TUC-2 - Cycles	22	8	35	24
TUC-3-Hours	6544	7218	6109	2138
TUC-3-Cycles	12	9	33	31
TUC-4 - Hours	7638	7707	5844	6183
TUC-4 - Cycles	50	56	164	123
TUC-5 - Hours	7727	7849	6884	6965
TUC-5 - Cycles	65	24	90	51
TUC-6 - Hours	6105	6940	6124	6742
TUC-6 - Cycles	90	66	61	43

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Request IR-66:

Reference: Exhibit N-6(ii), Control Center

There is a 42% forecasted increase in labour expense for 2026 over 2024 actuals in this category (as well as a significant projected increase over 2025 budget) despite a reduction of three employees due to transfer to the Nova Scotia Independent Energy System Operator (NSIESO). The reason given is due to additional employees for operational requirements.

(a) Please provide additional details about the significant increase in additional employees for operational requirements in 2026, just before they are transferred to the NSIESO in 2027.

(b) Please provide NS Power's actual and forecast annual number of full-time equivalent employees in its Control Center group from 2024 to 2028

Response IR-66:

(a) These additional resources are required immediately in the Control Centre due to the significant increase in IPP interconnection requests and as an outcome of the FAM Audit Dispatch Study. If the IESO-NS didn't exist, these additional employees would stay at the NS Power System Operator, but they are anticipated to transfer to the IESO-NS as part of the Phase 2 transition in 2027.

(b)

Year	Number of FTEs
2024 Actuals	64 due to vacancies at December 31
2025 Budget	76
2026 GRA	81
2027 GRA	43 as FTEs transferred to the IESO-NS
2028	NA – no forecast numbers available

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1 **Request IR-67:**

2
3 **Reference: Exhibit N-6(ii), Transmission & Distribution Contractor Management**

4
5 **There was a 133% increase in contracts expense in 2024 versus the forecast amount in the**
6 **2024 compliance. The explanation given for the higher costs over the 2024 compliance**
7 **forecast is due to increased maintenance on larger fleet and aging fleet vehicles, increased**
8 **utility services costs, and inflation. Please provide more information on the \$7.6 million**
9 **increase in 2024 expense compared to the compliance forecast for 2024.**

10
11 **Response IR-67:**

12
13 The increase in Fleet vehicle costs is a direct result of the increase of PLTs, Regional Planners and
14 Wiring Inspectors needed to execute the increased customer-requested work and reliability work.
15 With the significant supply chain challenges, more vehicles are being maintained for longer than
16 was historically the case.

17
18 The additional Utility Services costs are due to a large increase in Bell and other third-party work
19 that NS Power employees complete on behalf of the third parties. All these costs are recovered
20 through Other (non-electric) revenue by NS Power.

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Request IR-68:

Reference: Exhibit N-6(ii), Storm

The 2026 forecast for labour in this category is significantly higher than the 2024 actual, but in-line with the 2024 compliance restated.

(a) Did NS Power reduce its FTEs in this category during 2024 or are these non-salaried employees?

(b) There doesn't appear to be separate accounts used for level 3 and level 4 storms. If not, why not? Wouldn't this be the easiest way to track these costs for the storm rider?

(c) How are the level 3 and level 4 storm costs tracked separately from level 1 and level 2 if not by separate accounts? Is there a manual process of extracting data?

(i) If this is how its done, isn't this more cumbersome and time consuming than tracking in separate accounts?

Response IR-68:

(a) As per NS Power's Emergency Services Restoration Plan (ESRP) the majority of NS Power employees have storm roles, but NS Power does not have FTEs whose only role it is to respond to storms. Since most NS Power employees have storm roles, the storm labour forecasts are based on historical averages of internal labour required to respond to storms. Regular labour charged to Storm OM&G is for employees that charge to specific activities as opposed to a home cost centre. This includes unionized employees such as Powerline Technicians, Planners, Electricians, and Utility Workers. When non-union employees are assigned to a capital project(s), these employees are unable to charge to their assigned capital projects when they are undertaking storm restoration activities as the storm

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1 restoration activities are attributable to OM&G rather than capital. Employees who do not
2 charge to specific activities or projects (this excludes managers and above) are only eligible
3 to charge overtime labour costs to storm restoration activity.

4
5 During 2024, actual storm activity was less than the historical average, and therefore these
6 employees were able to focus on assigned customer-driven or customer-requested work or
7 other planned capital investment.

8
9 (b-c) NS Power tracks storm costs within individual projects in its project accounting software,
10 PowerPlan. Once a Level 3 or 4 event has been declared, a unique project name and number
11 are assigned for cost tracking. All storm OM&G are charged to cost centre 117. NS Power
12 can generate reports in PowerPlan by project, account, and cost centre to identify cost data
13 for Level 1 & 2 and Level 3 & 4 storms.

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1 **Request IR-69:**

2
3 **Reference: Exhibit N-6(ii), Grid Modernization and Customer Integration**

4
5 **There is a forecasted increase of 34% in labour in this category over 2024 actual. The reasons**
6 **given are additional resources in the Smart Meter Operations Center, primarily to support**
7 **data analytics, Customer Experience for expansion of customer focused initiatives, increased**
8 **requirements for Telecom and WAM support, and salary escalation.**

9
10 **(a) Please provide additional specific details on the increased requirements or expanded**
11 **initiatives in each of the mentioned areas from 2024 to 2026.**

12
13 **(b) Please comment on the need for additional resources in the Smart Meter Operations**
14 **Center to support data analytics, when NS Power's ability to obtain smart meter data**
15 **has been impacted by the cybersecurity attack.**

16
17 **(c) When does NS Power expect to be able to fully access smart meter data from customer**
18 **meters?**

19
20 **(d) How long will NS Power's customer meters store customer data? Has NS Power**
21 **already lost smart meter data because it was unable to access it due to the**
22 **cybersecurity attack?**

23
24 **Response IR-69:**

25
26 **(a) The increased requirements for the Smart Meter Operations Center are for data analytics**
27 **support. The incremental data analyst roles will leverage AMI, customer, and other data**
28 **sources to troubleshoot power quality concerns at customer premises, provide operational**
29 **reporting on Smart Meter Operations, respond to customer inquiries on billing and usage,**
30 **and support the design and evaluation of customer programs.**

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1 The incremental labour for Customer Experience supports the maintenance of the
2 expanding portfolio of digital solutions such as Green Button, My Energy Insights, the
3 customer-facing website, and the large complex customer portal planned for 2026. In
4 addition to the expanded digital channel support, the Customer Experience team is
5 delivering a Customer First, role-specific training program to educate employees in
6 delivering exceptional customer experience. The Customer Experience team is expanding
7 its communication initiatives with customers via media campaigns and in-person
8 engagements such as home shows to ensure customers have access to information and
9 expertise in managing their energy needs.

10
11 The incremental labour for Telecom support is for increased maintenance requirements for
12 new and upgraded telecommunications equipment. New Remote Terminal Unit
13 installations and new renewable generation interconnections are examples of initiatives
14 that increase the volume of telecom assets that require regular maintenance.

15
16 The incremental labour for WAM Support is for the maintenance of new business processes
17 that are deployed on the WAM platform. Expansion of business processes include new
18 requirements for maintaining system configurations and integrations, managing data
19 quality, and supporting new end users.

20
21 (b) NS Power data analysts are able to use smart meter data that was delivered from smart
22 meters up to the date of the cybersecurity attack (April 2025). Data analysts use this data
23 with other data sources to support the analytics described in part (a). Smart meters installed
24 across the province continue to measure customer usage and accumulate the overall energy
25 consumed at the meter, much like the odometer of a vehicle. Restoration of AMI
26 capabilities is expected in early 2026. This will return the overall usage of the meter to
27 support analytics as well the other meter data that supports the increased analytics as
28 forecast.

29
30 (c) NS Power expects to fully access smart meter data from customer meters in early 2026.

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1 (d) NS Power smart meters measure and maintain the total energy consumed at a meter, much
2 like the odometer of a vehicle. This measurement will not be lost as a result of the
3 cybersecurity attack. Other meter data stored at the meter, such as 15-minute interval usage
4 and meter notifications, are stored for a range of 60 to 90 days, depending on the meter
5 configuration. Most residential customer meters store 90 days of this data. Bi-directional
6 residential meters and commercial meters store 60 days of this data. Due to the time
7 required to restore AMI systems, some of the meter notifications and interval
8 measurements will be lost due to the cybersecurity attack.

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1 **Request IR-70:**

2
3 **Reference: Exhibit N-6(ii), Corporate Adjustments.**

4
5 **(a) Please explain what the vacancy adjustment is (under labour), and how it was treated**
6 **previously.**

7
8 **Response IR-70:**

9
10 (a) The labour vacancy adjustment is a reduction to the Company's overall labour forecast to
11 reflect the assumption that all positions included in the 2026-2027 GRA budget will not be
12 filled at all times. This reduction in the labour budget is related to unexpected staffing
13 turnover and is an additional reduction to expected staffing vacancies which are included
14 in departmental budgets. In previous GRAs NS Power did not include a labour vacancy
15 adjustment, as it assumed full staffing levels for all budgeted positions. This approach was
16 based on the expectation that vacancies would be temporary and managed within
17 departmental budgets. Recent analysis of vacancy trends and turnover rates has
18 demonstrated that these impacts are significant enough to warrant a formal vacancy
19 adjustment to improve forecast accuracy.

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1 **Request IR-71:**

2
3 **Reference: Exhibit N-14, OP-03, Attachment 1, ScottMadden Report**

4 **In a number of instances, the ScottMadden Report includes a discussion of “Factors**
5 **Contributing to Performance” along with its observations. Please explain why these factors**
6 **appear to offer exogenous or structural reasons in areas where NS Power’s performance**
7 **may appear to be poorer or trending poorer compared to its peers, but no similar comments**
8 **are made to highlight similar factors that NS Power may be benefitting from in areas where**
9 **the data shows its performance to be superior to its peers.**

10
11 **Response IR-71:**

12
13 As noted in NS Power’s direct evidence, the benchmarking study shows that NS Power’s costs are
14 below or in line with electric utility norms, and NS Power performs favourably compared to its
15 peers, generally in the top quartile. As this was consistent with the benchmarking study produced
16 for the last GRA, the focus was primarily on providing potential explanations for areas in which
17 NS Power’s results did not appear to be favourable.

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Request IR-72:

Reference: Exhibit N-14, OP-03, Attachment 1, ScottMadden Report, p. 12 of 87, Peer Group Selection

(a) Is the entire universe of regulated US electric operating companies limited to 149 companies? If not, how was the starting point determined?

(b) Were any US utilities that are vertically integrated (production, transmission, and distribution functions) or diversified (electric and gas) excluded from the 103 companies at step 2 of the screening process? If so, which ones and why?

(c) Were any US utilities of comparable scale (total plant between \$2.5B and \$12.5B, number of customers between 250,000 and 1,300,000, and generation capacity between 700 MW and 4,000 MW) excluded from the 25 companies at step 3 of the screening process? If so, which ones and why?

(d) Why were each of the following US utilities that have fewer than 250,000 customers included in the peer group: Duke Energy Kentucky, Inc., Empire District Electric Company, Kentucky Power Company, MDU Resources Group, Inc., Monongahela Power Company, Otter Tail Power Company and Southern Indiana Gas and Electric Co.?

(e) Please explain how the NERC regions were used to screen US utilities. Which regions were excluded, and why?

(f) Please provide a flow chart, similar to the one shown for US utilities, to describe how the Canadian utilities were selected.

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1 **(g) Please identify which of the Canadian utilities included in the peer group would have**
2 **been excluded if the screening criteria applicable to US utilities (total plant between**
3 **\$2.5B and \$12.5B, number of customers between 250,000 and 1,300,000, and**
4 **generation capacity between 700 MW and 4,000 MW) were used.**

5
6 Response IR-72:

7
8 (a) ScottMadden defined regulated US electric operating companies as having at least two of
9 the following: electric generation, electric transmission, or electric distribution (i.e., no
10 stand-alone generation, transmission, or distribution companies). Based on this definition,
11 ScottMadden's universe of regulated US electric operating companies included electric-
12 only and combined electric and gas distribution companies. Today, there are 142
13 companies that meet this definition.

14
15 (b) No.

16
17 (c) ScottMadden inadvertently made a data entry error in the "Customers" column of the peer
18 panel table that it reviewed with NS Power. Because of this error, ScottMadden incorrectly
19 excluded from the original benchmarking report five companies that did meet the screening
20 criteria: AES Indiana, Cleco Power, Evergy Kansas South, Northern Indiana Public Service
21 Co., and Westar Energy (KPL). These five companies have been added to the updated
22 benchmarking report included as Attachment 1. The updated benchmarking report also
23 excludes seven companies that were incorrectly included in the original benchmarking
24 report, as described in sub-part (d) below. ScottMadden's findings do not have any
25 substantive changes in the updated benchmarking report.

26
27 (d) The data entry error noted in sub-part (c) above resulted in ScottMadden incorrectly
28 including seven companies in the original benchmarking report: Duke Energy Kentucky,
29 Inc., Empire District Electric Company, Kentucky Power Company, MDU Resources
30 Group, Inc., Minnesota Power Enterprises, Otter Tail Power Company, and Southern

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1 Indiana Gas and Electric Co. (Monongahela Power Company was listed in part (d) of this
2 IR but was correctly included in the peer group; Minnesota Power was not listed in part (d)
3 of this IR but was incorrectly included in the peer group). These seven companies have
4 been deleted in the updated benchmarking report (as well as the inclusion of five companies
5 described in part (c) above). ScottMadden's findings do not have any substantive changes
6 in the updated benchmarking report.

7
8 (e) The following NERC regions were excluded from screening US utilities due to their
9 proximity, climate, and operating characteristics:

- 10 • SERC Reliability Corporation (SERC)
- 11 • Texas Reliability Entity (Texas RE)
- 12 • Western Electricity Coordinating Council (WECC), except for the Northwest
13 Power Pool (NWPP) sub-region

14
15 (f) ScottMadden was provided the list of the Canadian utilities by NS Power.

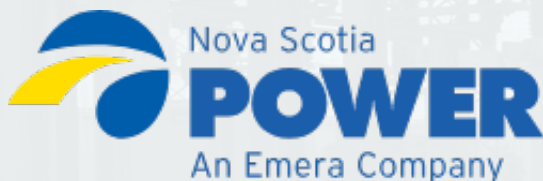
16
17 (g) If the same screening criteria applicable to US utilities were applied to the Canadian
18 utilities then Nova Scotia Power Inc., New Brunswick Power, and ATCO Electric would
19 have been included.



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Nova Scotia Power Benchmarking Analysis

2025

UPDATED 10/30/25

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Glossary of Acronyms Used in the Report

- A&G – Administrative and General
- AMI – Advanced metering infrastructure
- APQC – American Productivity & Quality Center
- ACFB – Atmospheric circulating fluidized bed
- AZNMSN – Arizona, New Mexico and Southern Nevada
- CAD – Canadian dollars
- CAGR – Compound annual growth rate
- CAMX – California-Mexico sub-region of WECC
- CAPS – Center for Advanced Procurement Studies
- CC – Gas-fired combined cycle blocks
- CoalST – Coal-fired steam turbine
- EIA – Energy Information Administration
- ERP – enterprise resource planning
- FERC – Federal Energy Regulatory Commission
- FP – Florida Peninsula sub-region of SERC
- FTE – Full-time equivalent
- GATEWY – Gateway sub-region of SERC
- HFOST – Heavy fuel oil steam turbine
- HR – Human resources
- kWh – kilowatt-hour
- LED – light-emitting diode
- MW – Megawatt
- MWh – Megawatt-hour
- MRO – Midwest Reliability Organization
- MRO-US – U.S. sub-region of MRONA – Not available
- NE – Northeast sub-region of NPCC
- NPCC – Northeast Power Coordinating Council
- NSPI – Nova Scotia Power Inc.
- NWPP – Northwest Power Pool
- NY – New York sub-region of NPCC
- OM&G – Operating, maintenance & general
- PO – Purchase order
- psi – pounds per square inch
- RFC – Reliability First Corporation
- RMPA – Rocky Mountain Power sub-region of WECC
- R-MISO – MISO sub-region of RFC
- ROW – Right of way
- R-PJM – PJM sub-region of RFC
- SERC – Southeast Reliability Corporation
- SOU – Southeastern sub-region of SERC
- SPP – Southwest Power Pool
- T&D – Transmission and Distribution
- TRE – Texas Reliability Entity
- U.S. – United States
- USD – United States dollars
- WECC – Western Electric Coordinating Council



Executive Summary



Executive Summary

- Nova Scotia Power Inc. (NSPI) commissioned this benchmarking effort in 2024 to provide useful directional-based insights around OM&G and capital costs, allowing NSPI to better understand how its overall performance compared to peers
- While every attempt was made to align functional data across peer companies and to understand differences reflected in the data, it is important to recognize that there are limitations to this approach, including:
 - The functions included in this study are typical of work performed at an electric utility, but they are still open to interpretation and functional costs are dependent on the terminology used by each organization
 - Company data and reports are typically aligned around the organizational structure of each company and not the work performed in each function, requiring available cost data to be realigned to the functions using other methods
- Given the diversity and variability of operations between utilities, inherent cost differences are unavoidable between peer companies. The data provided by NSPI is comparable to the data compiled for the peers; however, it should be noted other factors may influence results in a specific area. This does not diminish the benefits of this work, but demonstrates some of the limitations of benchmarking analyses
- Key Conclusions:
 - Overall, NSPI OM&G costs compare favorably to the peer group, i.e., NSPI is in the first quartile for most metrics despite low usage per customer compared to peers. ~~Since 2021, the positive gap between NSPI and its peers has decreased as NSPI's Total OM&G expenses has grown faster than its peers~~
 - NSPI Transmission ~~and Distribution~~ OM&G costs are ~~both~~ first quartile in the peer group on a per Retail MWh Sold ~~and~~, per Kilometer of Transmission ~~/Distribution~~ Line, ~~and per Retail Customer~~ basis. NSPI Distribution OM&G costs are first quartile in the peer group on a per Retail Customer and per Retail MWh Sold basis, and at the first/second quartile line in the peer group on a per Kilometer of Distribution Line basis. The positive gap between NSPI and its peers has ~~closed decreased~~ given 2023 storm expenses, customer growth, increased investment in reliability and significant growth in customer requested work
 - NSPI Production OM&G per MWh Generated at an enterprise-level and at the plant-level compares favorably to peers, ~~ranking in the first quartile and~~ among the lowest compared to peers for all metrics
 - NSPI Customer Accounts OM&G per Retail Customer and per Retail MWh Sold are **in the first quartile and** at the first/second quartile line, **respectively**, compared to the peer group and have increased at a slower rate than peers
 - A&G costs as a whole are also favorable compared to the peer group
 - NSPI Capital Employed per Retail Customer is below the median and lowest among all peers

OM&G and Reliability Metrics

Category	5-Year Average		NSPI Performance
	Median	NSPI	
Total OM&G*			
Total OM&G* as % of Retail Revenue	~~30%~~ 29%	18%	
Total OM&G* per Retail Customer	~~\$1,023~~ \$951	\$506	
Total OM&G* per Retail MWh Sold	~~\$40.28~~ \$39.67	\$26.44	
Power Production			
Production OM&G* Per MWh Generated	~~\$11.74~~ \$11.03	\$9.69	
Customer Accounts			
Customer Accounts OM&G per Retail Customer	~~\$82.10~~ \$73.70	\$47.70	
Customer Accounts OM&G per Retail MWh Sold	~~\$3.16~~ \$2.88	\$2.51	 UPDATED

Category	5-Year Average		NSPI Performance
	Median	NSPI	
Transmission & Distribution			
Transmission OM&G per Retail MWh Sold	~~\$7.35~~ \$5.36	\$1.70	
Transmission OM&G per Km of Transmission Line	~~\$8,704~~ \$25,033	\$4,311	
Distribution OM&G per Retail Customer	~~\$132~~ \$122	\$78	
Distribution OM&G per Retail MWh Sold	~~\$5.34~~ \$5.13	\$4.10	
Distribution OM&G per Km of Distribution Line	~~\$1,920~~ \$1,813	\$1,512	
Administrative & General			
A&G OM&G as % of Retail Revenue	~~9.1%~~ 9.0%	4.6%	
A&G OM&G per Retail Customer	~~\$266~~ \$301	\$131	
A&G OM&G per Retail MWh Sold	~~\$11.12~~ \$12.20	\$6.85	

Key:

Arrows	Trend in metric between 2019 and 2023 (e.g., up = improved performance)**
Green	5-year average is first quartile
Blue	5-year average is second quartile
Yellow	5-year average is third quartile
Red	5-year average is fourth quartile

*Excludes fuel and purchased power costs.

**If change was immaterial, deemed flat.

Capital Additions Metrics

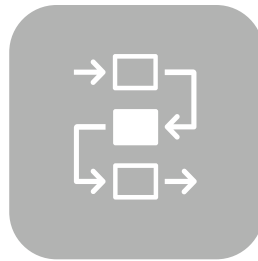
Category	5-Year Average	
	Median	NSPI
Total Plant Additions		
Total Capital Employed per Retail Customer	~~\$11,778~~ \$10,350	\$7,753
Total Plant Additions as % of Total Electric Plant	~~6.4%~~ 5.6%	5.1%
Total Plant Additions as % of Depreciation Expense	~~216%~~ 186%	147%
Production Capital Additions		
Production Additions as % of Production Plant	~~3.0%~~ 2.8%	2.9%
Production Additions as % of Depreciation Expense	~~107%~~ 87%	100%
Transmission and Distribution Capital Additions		
Transmission Additions as % of Transmission Plant	~~7.2%~~ 7.1%	4.7%
Transmission Additions as % of Depreciation Expense	~~306%~~ 304%	194%
Distribution Additions as % of Distribution Plant	7.0%	8.2%
Distribution Additions as % of Depreciation Expense	~~254%~~ 259%	192%
General Plant Capital Additions		
General Plant Additions as % of General Plant	~~9.8%~~ 8.6%	9.8%
General Plant Additions as % of Depreciation Expense	~~252%~~ 201%	159%

Corporate Support Metrics

Category	Industry Group Median	NSPI 2023	NSPI Performance
Finance & Accounting Metrics			
Invoices Processed per Full Time Equivalent (FTE)	9,540	7,548	
% Electronic Invoices/ Paperless Payments	50%	88%	
Finance & Accounting Cost as % of Revenue	0.54%	0.36%	
Cost per Invoice	\$1.77	\$.73	
Human Resources Metrics			
Total HR Cost per Employee	\$1,294	\$1,567	
Number of Employees per HR Function FTE	82.3	139.7	
Time to Fill (Days)	30.0	53.5	

Key:	
Green	NSPI performs more favorably than the median
Blue	NSPI performs in line with the median
Red	NSPI performs less favorably than the median
	Metric does not have a favorable/unfavorable connotation

Category	Industry Group Median	NSPI 2023	NSPI Performance
Supply Chain Metrics			
Total Cost to Procure per \$1,000 Revenue	\$3.91	\$3.27	
% of Supply Management Positions that are Strategic	43%	30%	
Cycle Time to Issue a Purchase Order for Goods	2.0	6.3	
Number of PO Line Items Processed per FTE	8,058	4,978	
Number of POs Processed per FTE	1,600	1,687	
Information Technology Metrics			
Total IT Cost per \$1,000 Revenue	\$20.00	\$29.26	
Total IT Cost per Business Entity FTE	\$30,137	\$22,430	
% of Total IT Cost Allocated to Capital Costs	30%	32%	



Approach



Methodology

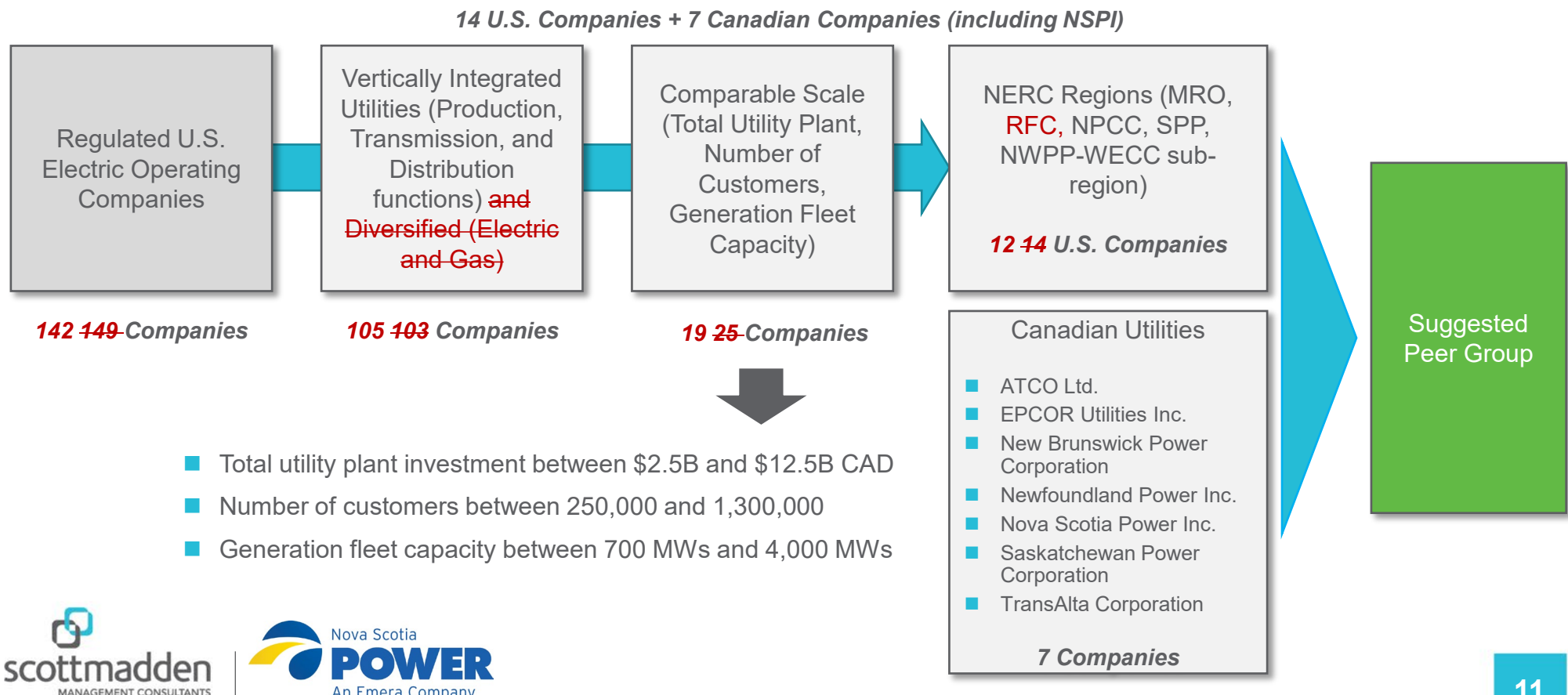
- The report was prepared by ScottMadden, Inc. with the support of NSPI personnel
 - ScottMadden, Inc. (ScottMadden) is a management consulting firm with recognized leadership in utility business planning and benchmarking
- ScottMadden, assisted by NSPI:
 - Identified key performance metrics which would be benchmarked
 - Identified the most appropriate peer groups for comparison
 - Prepared supporting analyses, charts and the final report
- NSPI personnel responsible for the designated performance metrics assisted the effort by supplying the NSPI data used for benchmarking and providing insights into the factors contributing to current operational performance
 - Data provided by NSPI was not independently verified by ScottMadden

Peer Group Selection

This benchmarking analysis compares NSPI performance against a peer group of **18 20** other North American regulated utilities, six of which are Canadian.

- FERC Form 1 filings were the source of U.S. utility data
- A combination of annual reports, annual filings with provincial regulators, and other public material were used to collect Canadian utility data
- Data for some peers, particularly the Canadian utilities, was not available for all metrics. If data was not available for a specific metric, the peer utility was excluded from that analysis

The peer utility group was selected based on the following criteria:



Peer Fossil Plant Selection

The analysis also compares the performance of NSPI's fossil plants against peer plants.

- NSPI data was compared to cost data from publicly-available sources such as FERC and EIA, as well as non-publicly-available data from S&P Global Market Intelligence (a data subscription service) that models unit-level cost data based on specific unit emissions data, locational marginal pricing and dispatch data, and other factors

The peer plant groups were selected based on the following criteria:

- Subcritical Coal-Fired Steam Turbines:
 - Prime mover: Steam turbine
 - Primary fuel: Coal
 - Main steam pressure: <2,800 psi (subcritical)
 - Capacity: 100-200 MW
 - Commercial date: 1960-1991
 - Region excluded: AZNMSN
 - Capacity factor excluded: 5-year Average of <5%
- Coal-Fired Fluidized Bed Reactors
 - Prime mover: Steam turbine
 - Primary fuel: Coal
 - Technology: Fluidized bed reactor
 - Capacity: >20 MWs
 - Commercial date: 1965-1976
 - U.S. states excluded: Florida, Hawaii, Virginia
 - Capacity factor excluded: 5-year Average of <5%
- Subcritical Oil and Gas-Fired Steam Turbines:
 - Prime mover: Steam turbine
 - Primary fuel: Oil and gas
 - Main steam pressure: <2,800 psi (subcritical)
 - Capacity: 80-185 MW
 - Commercial date: 1965-1976
 - Region excluded: AZNMSN
 - Capacity factor excluded: 5-year Average of <5%
- Gas-Fired Combined Cycle Blocks
 - Prime mover: Combined cycle blocks
 - Primary fuel: Gas
 - Configuration: 2 Generating Turbines x 1 Steam Turbine/Heat Recovery Steam Generator
 - Block capacity: 75-250 MWs
 - Commercial date: 1998-2012
 - Co-generator: No
 - Region excluded: TRE
 - Capacity factor excluded: 5-year Average of <5%

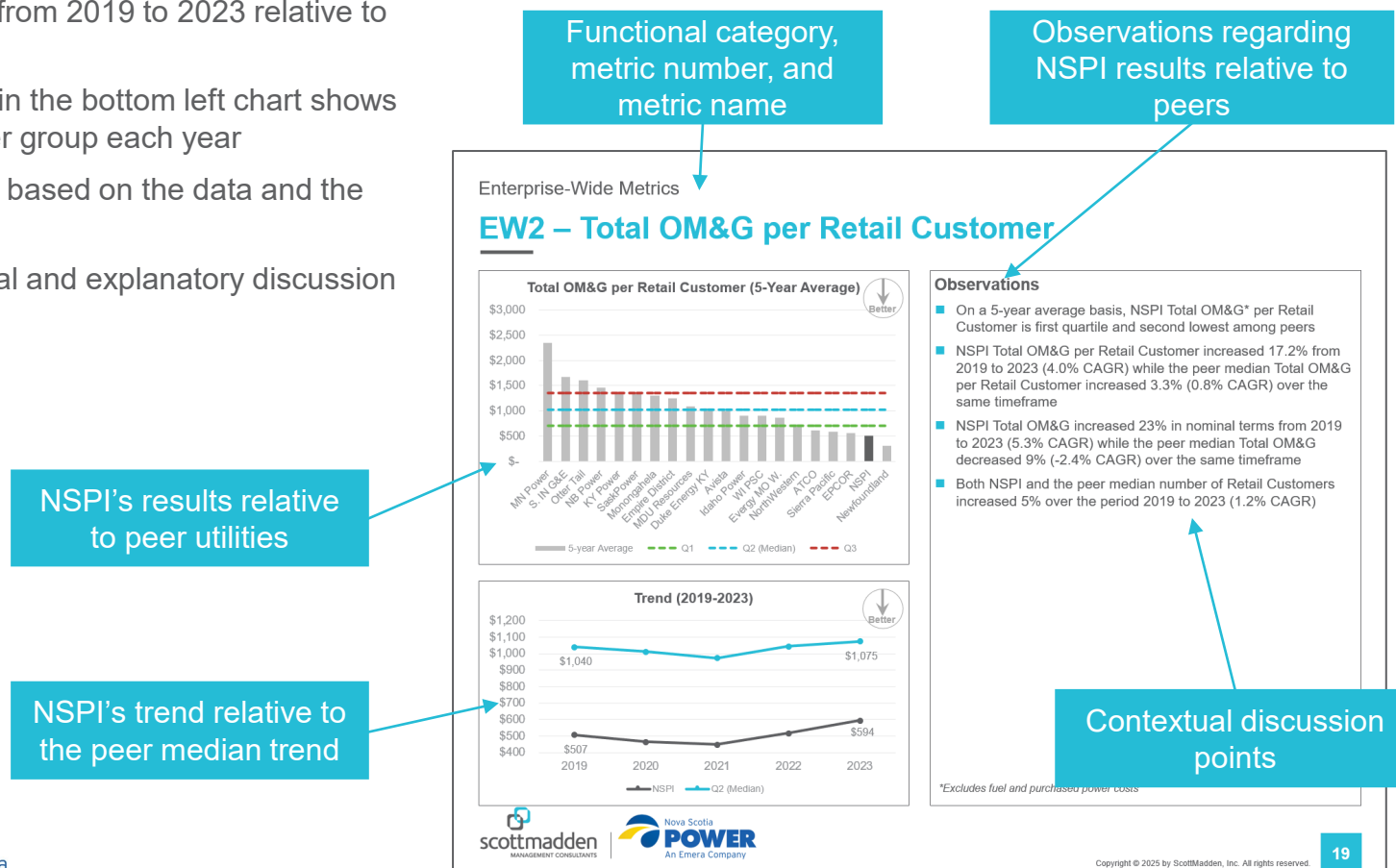
Peer Group Selection – Corporate Support Metrics

- For the Corporate Support metrics, benchmarks from APQC (American Productivity and Quality Center) and CAPS (Center for Advanced Procurement Studies) were utilized
- Peers within APQC and CAPS are not individually identified. Members are invited to participate in benchmarking research by APQC and CAPS and aggregate results from those who participated are provided for comparison
 - APQC is a non-profit organization who provides independent, unbiased and validated research and data to members and industries
 - CAPS (capsresearch.org) was established in 1986 as a partnership between the W. P. Carey School of Business at Arizona State University (<https://wpcarey.asu.edu/>) and the Institute for Supply Management (<https://www.instituteforsupplymanagement.org>)
- Benchmarks were retrieved from the most recent third-party sources that were available. Timelines of third-party benchmarking studies are set by third-party sources and may not align with each other; peer group composition may differ between metrics

Presentation of Results – Operational Metrics

Pages presenting operational metrics (i.e., enterprise-wide, transmission & distribution, power production, and customer operations) will resemble the figure below.

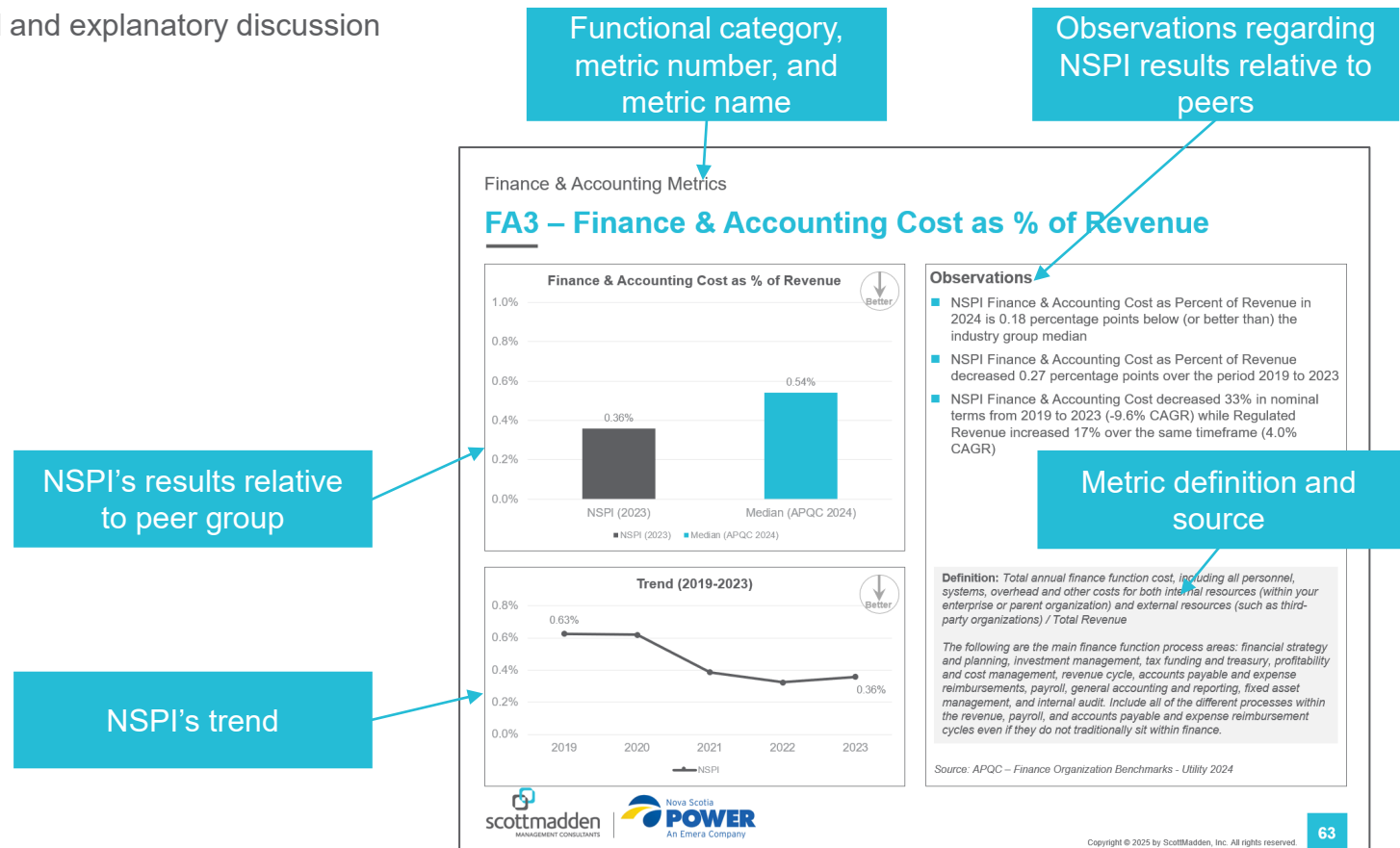
- **Top left chart:** NSPI's results relative to peer utilities (any dollars shown are CAD)
 - Unless otherwise specified, the results are based on a 5-year average to help normalize year-to-year outliers which can be misleading in determining the direction of overall performance
 - Individual peer utility 5-year averages are depicted in bars (NSPI is the dark-shaded bar), and 5-year average quartiles are represented by dotted horizontal lines
- **Bottom left chart:** NSPI's trend from 2019 to 2023 relative to the peer median trend
 - The Q2 (Median) trend line in the bottom left chart shows the median value of the peer group each year
- **Top right section:** Observations based on the data and the benchmarking results
- **Bottom right section:** Contextual and explanatory discussion points, if applicable

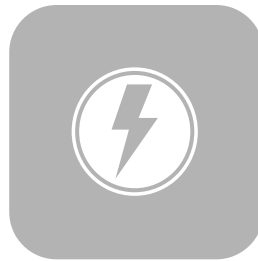


Presentation of Results – Corporate Support Metrics\

Pages presenting corporate support metrics (i.e., Finance & Accounting, HR, and Supply Chain) will resemble the figure below.

- **Top left chart:** NSPI's results relative to the benchmark median and any quartiles, if available (any dollars shown are CAD)
 - Unless otherwise specified, the results show 2023 NSPI data and the most recent benchmark value
- **Bottom left chart:** NSPI's trend from 2019 to 2023
- **Top right section:** Observations based on the data and the benchmarking results
- **Bottom right section:** Contextual and explanatory discussion points, if applicable

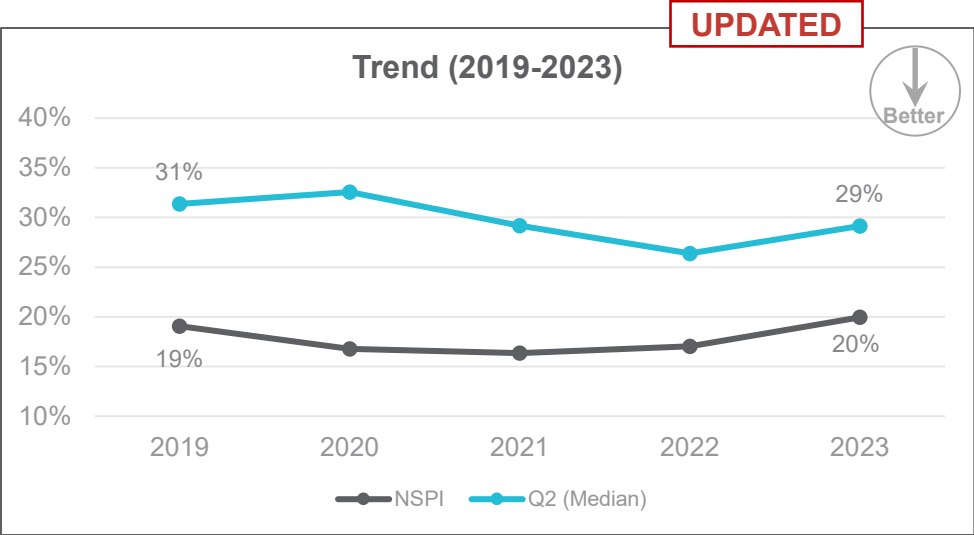
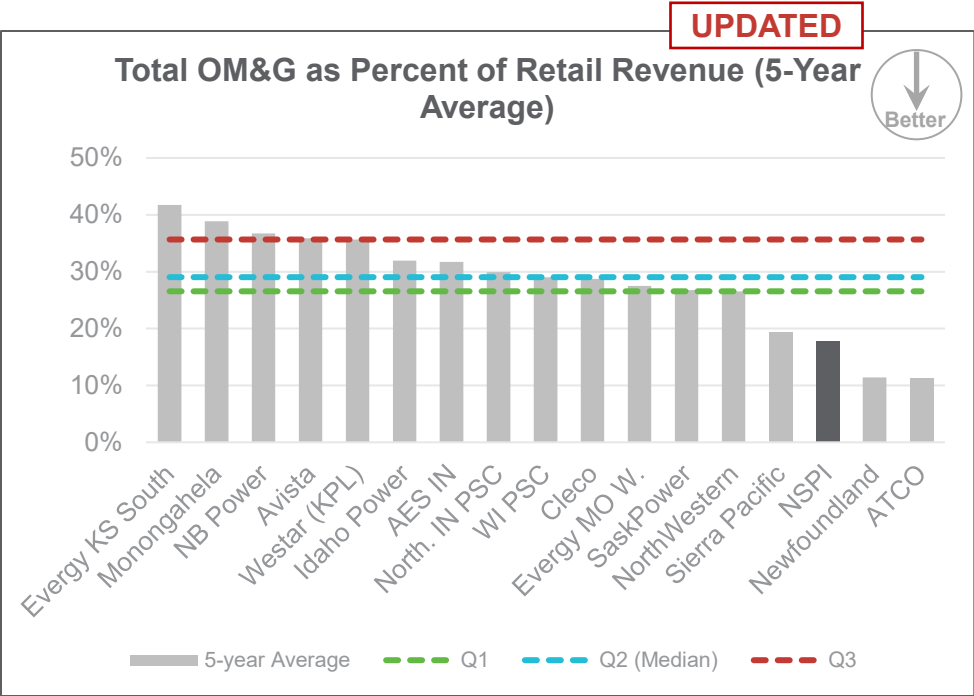




Enterprise-Wide Metrics



EW1 – Total OM&G as Percent of Retail Revenue

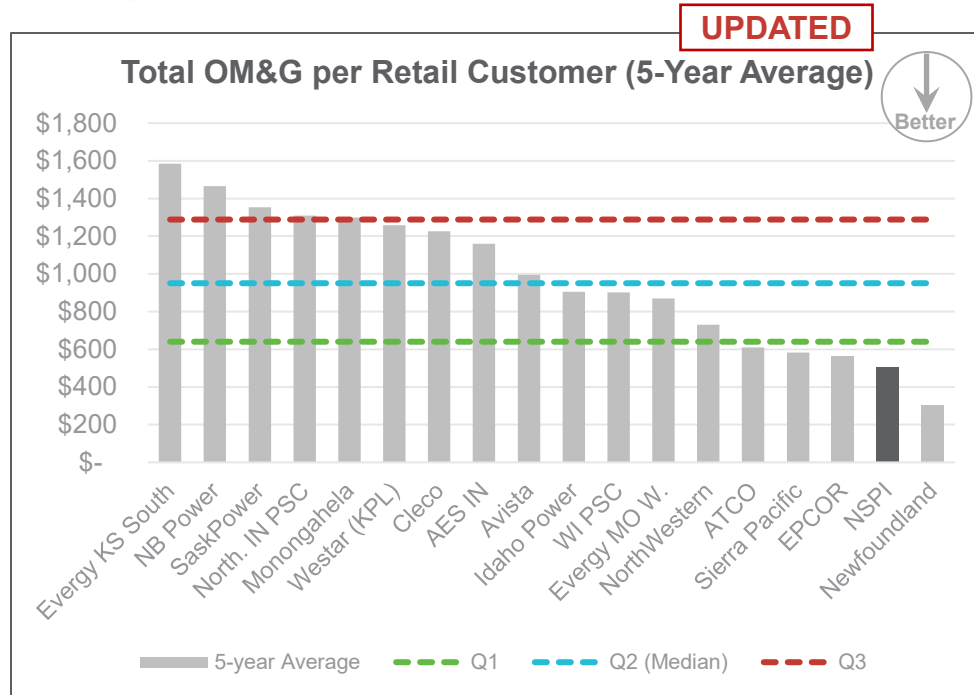


Observations

- On a 5-year average basis, NSPI Total OM&G* as Percent of Retail Revenue is first quartile and third lowest among peers
- NSPI Total OM&G as Percent of Retail Revenue increased 1 percentage point overall from 2019 to 2023, with a dip in 2020-2022, while the peer median Total OM&G as a Percent of Retail Revenue decreased 2.3 percentage points over the same timeframe
- NSPI Total OM&G increased 23% in nominal terms from 2019 to 2023 (5.3% CAGR) while the peer median Total OM&G increased 18% (4.3% CAGR) decreased 9% (-2.4% CAGR) over the same timeframe
- NSPI Retail Revenue increased 17% in nominal terms from 2019 to 2023 (4.1% CAGR) while the peer median Retail Revenue increased 14% 21% over the same timeframe (3.4% CAGR) (4.8% CAGR)

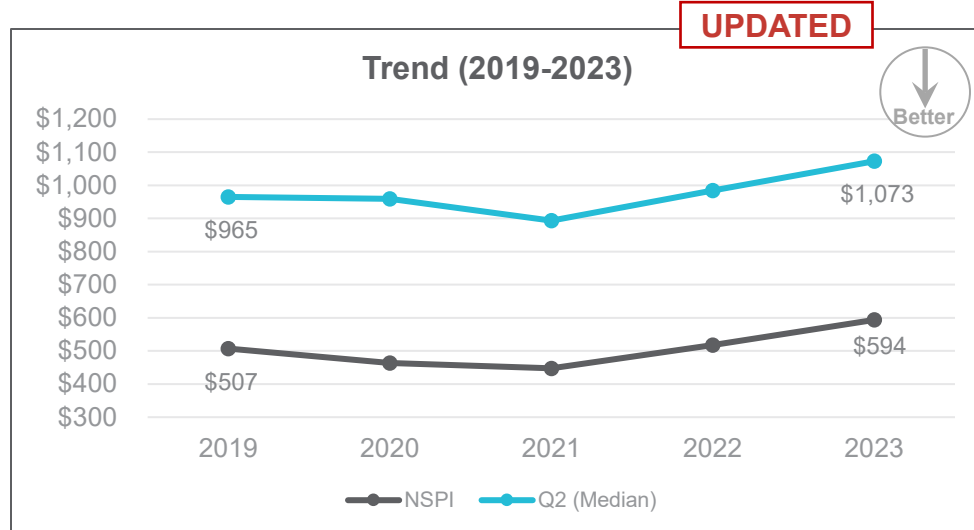
*Excludes fuel and purchased power costs

EW2 – Total OM&G per Retail Customer



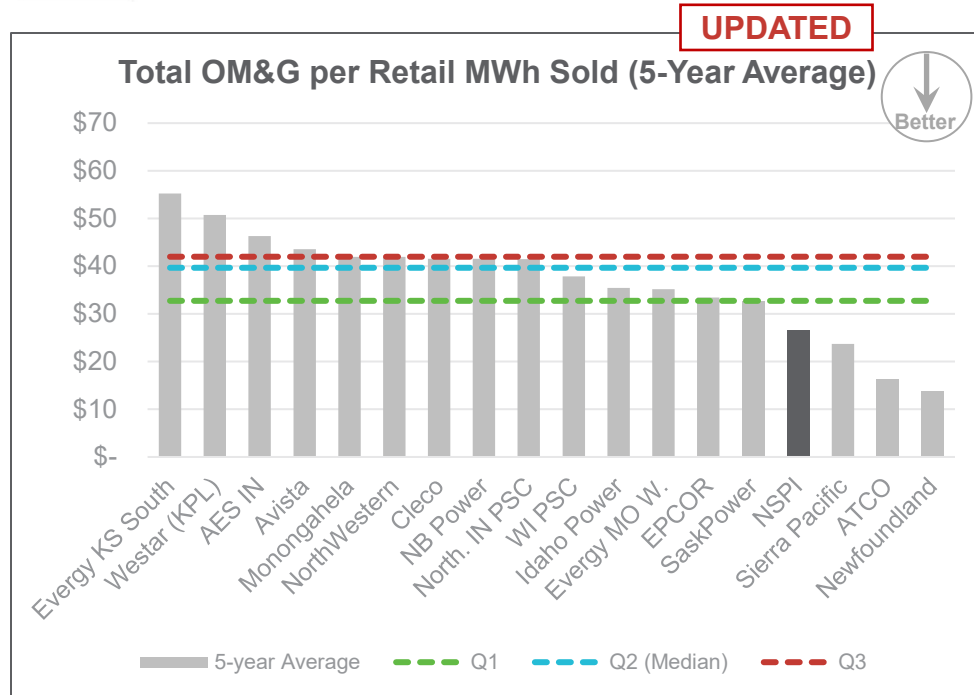
Observations

- On a 5-year average basis, NSPI Total OM&G* per Retail Customer is first quartile and second lowest among peers
- NSPI Total OM&G per Retail Customer increased 17.2% from 2019 to 2023 (4.0% CAGR) while the peer median Total OM&G per Retail Customer increased **11.1% (2.7% CAGR) 3.3% (0.8% CAGR)** over the same timeframe
- NSPI Total OM&G increased 23% in nominal terms from 2019 to 2023 (5.3% CAGR) while the peer median Total OM&G **increased 18% (4.3% CAGR) decreased 9% (-2.4% CAGR)** over the same timeframe
- **Both NSPI and the peer median** number of Retail Customers increased 5% over the period 2019 to 2023 (1.2% CAGR) **while the peer median number of Retail Customers increased 2% (0.4%) over the same timeframe**



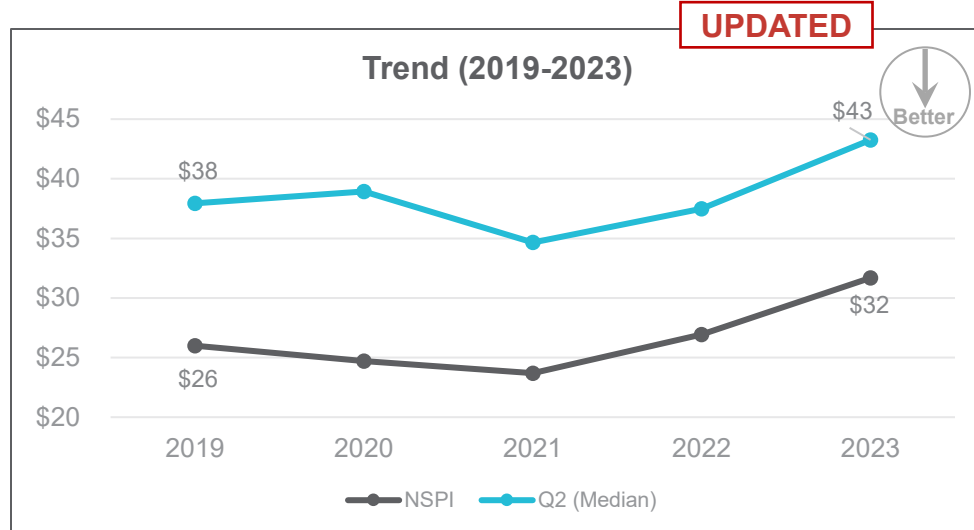
*Excludes fuel and purchased power costs

EW3 – Total OM&G per Retail MWh Sold



Observations

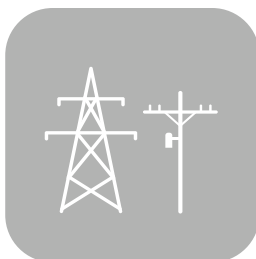
- On a 5-year average basis, NSPI Total OM&G* per Retail MWh Sold is first quartile and fourth lowest among peers
- NSPI Total OM&G per Retail MWh Sold increased 22% from 2019 to 2023 (5.1% CAGR) while the peer median Total OM&G per Retail MWh Sold increased ~~14%~~ ~~9%~~ over the same timeframe (~~3.3% CAGR~~) (~~2.3% CAGR~~)
- NSPI Total OM&G increased 23% in nominal terms from 2019 to 2023 (5.3% CAGR) while the peer median Total OM&G ~~increased 18% (4.3% CAGR)~~ ~~decreased 9% (-2.4% CAGR)~~ over the same timeframe
- NSPI Retail MWh Sold increased slightly by 1% (0.2% CAGR) from 2019 to 2023 while the peer median Retail MWh Sold ~~decreased~~ ~~increased~~ by ~~0.9%~~ ~~3%~~ over the same timeframe (~~-0.2% CAGR~~) (~~0.7% CAGR~~)



*Excludes fuel and purchased power costs

Summary Observations

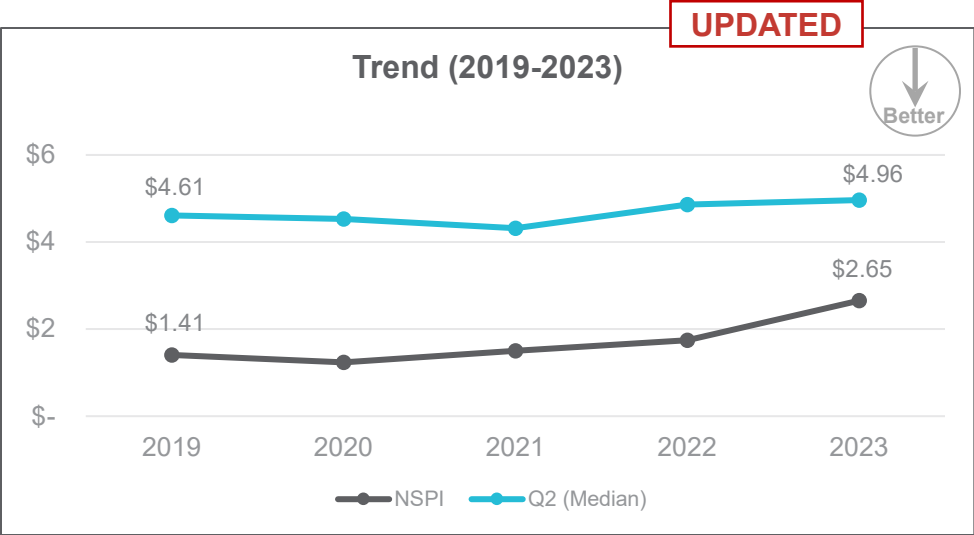
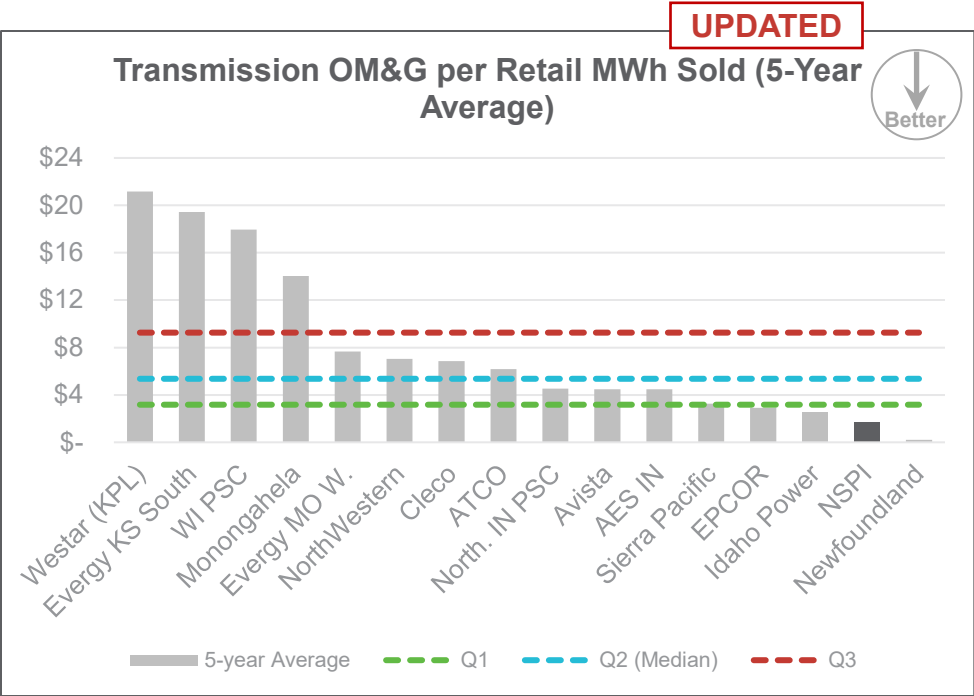
- NSPI Total OM&G as a Percent of Revenue, and on a per Revenue MWh Sold and per Retail Customer basis, are among the lowest in the peer group
- ~~While~~ NSPI continues to perform well against its peers in these metrics, ~~and~~ the positive gap between NSPI and its peers remained relatively consistent ~~through 2021, but the gap decreased since then as NSPI's Total OM&G expenses grew faster than its peers~~



Transmission & Distribution Metrics



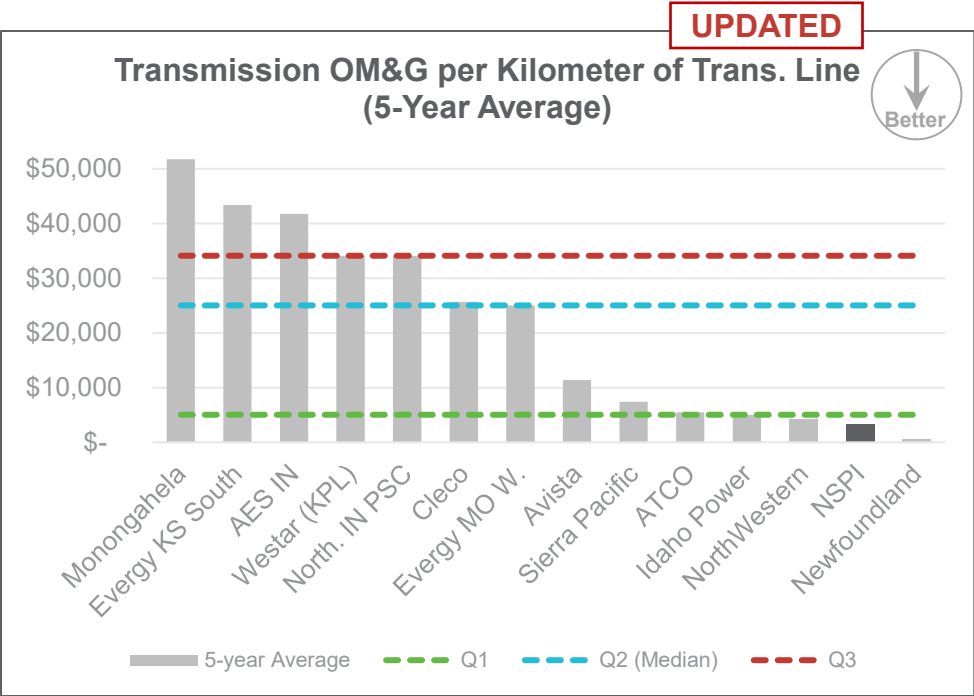
TD1 – Transmission OM&G per Retail MWh Sold



Observations

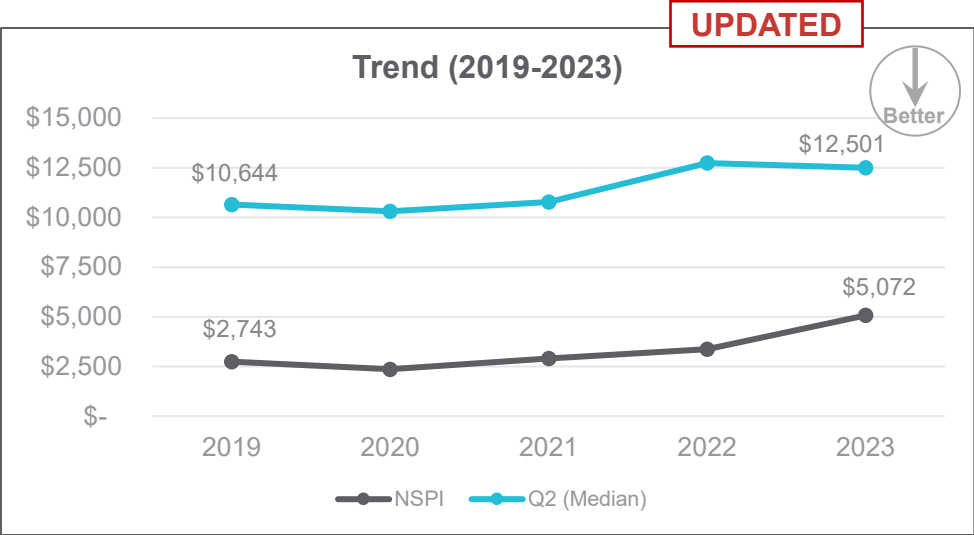
- On a 5-year average basis, NSPI Transmission OM&G per Retail MWh Sold is first quartile and second lowest among peers
- NSPI Transmission OM&G per Retail MWh Sold increased 89% from 2019 to 2023 (17.2% CAGR), primarily in the last year, while the peer median Transmission OM&G per Retail MWh Sold increased ~~8%~~ ~~6%~~ over the same timeframe (~~1.9% CAGR~~) (~~1.5% CAGR~~)
- NSPI Transmission OM&G increased 90% in nominal terms from 2019 to 2023 (17.4% CAGR) while the peer median Transmission OM&G increased ~~13%~~ ~~42%~~ over the same timeframe (~~3.2% CAGR~~) (~~9.3% CAGR~~)
- NSPI Retail MWh Sold increased slightly by 1% (0.2% CAGR) from 2019 to 2023 while the peer median Retail MWh Sold ~~decreased 0.9%~~ ~~increased 3%~~ over the same timeframe (~~-0.2% CAGR~~) (~~0.7% CAGR~~)

TD2 – Transmission OM&G per Km of Transmission Line

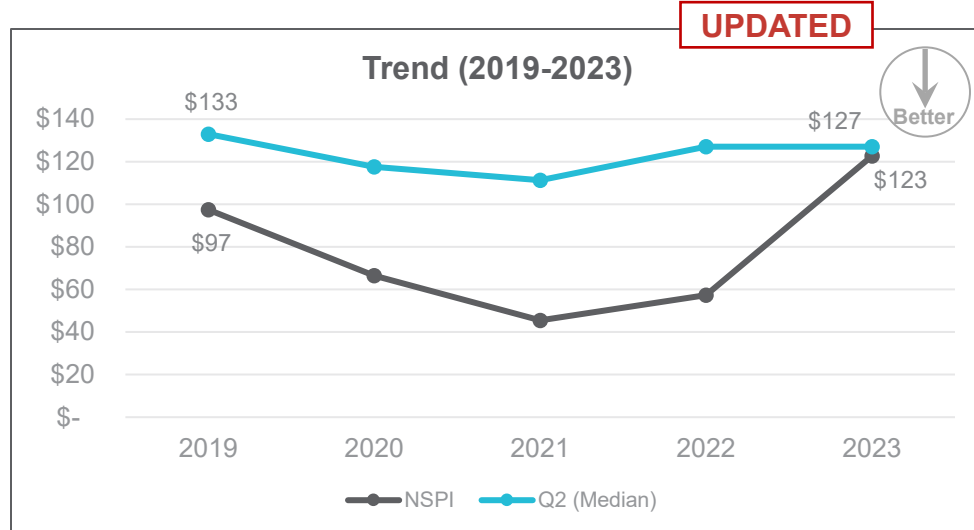
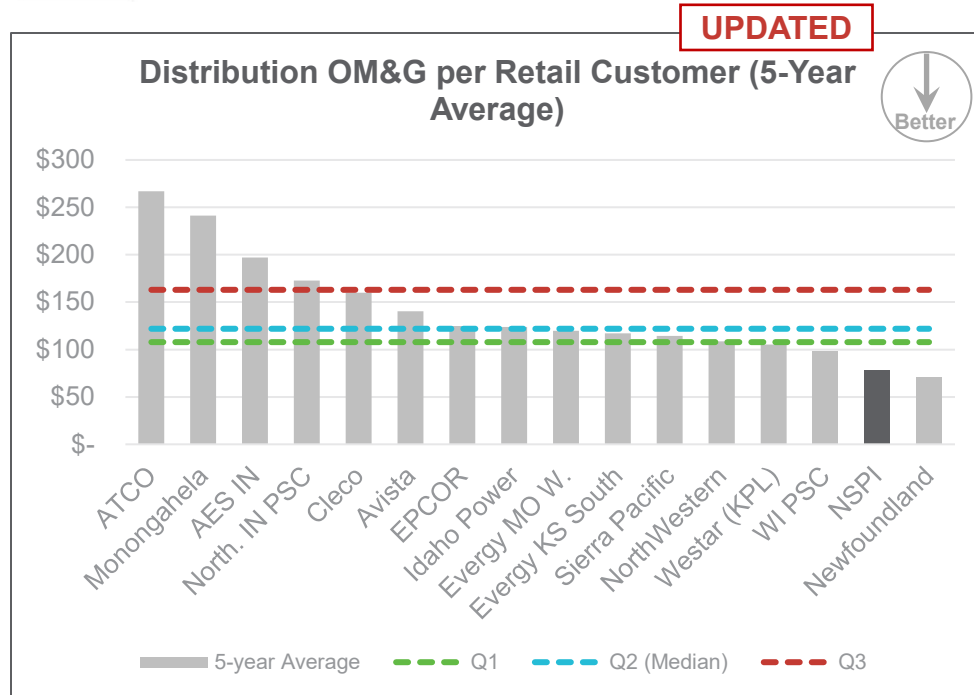


Observations

- On a 5-year average basis, NSPI Transmission OM&G per Kilometer of Transmission Line is first quartile and second lowest among peers
- NSPI Transmission OM&G per Kilometer of Transmission Line increased 85% from 2019 to 2023 (16.6% CAGR) while the peer median Transmission OM&G per Kilometer of Transmission Line increased 17% ~~62%~~ over the same timeframe (4.1% CAGR) ~~(12.7% CAGR)~~
- NSPI Transmission OM&G increased 90% in nominal terms from 2019 to 2023 (17.4% CAGR) while the peer median Transmission OM&G increased 13% ~~42%~~ over the same timeframe (3.2% CAGR) ~~(9.3% CAGR)~~
- NSPI Kilometers of Transmission Line increased 3% from 2019 to 2023 (0.7% CAGR) while the peer median Kilometers of Transmission Line decreased 1% over the same timeframe (-0.3% CAGR)



TD3 – Distribution OM&G per Retail Customer



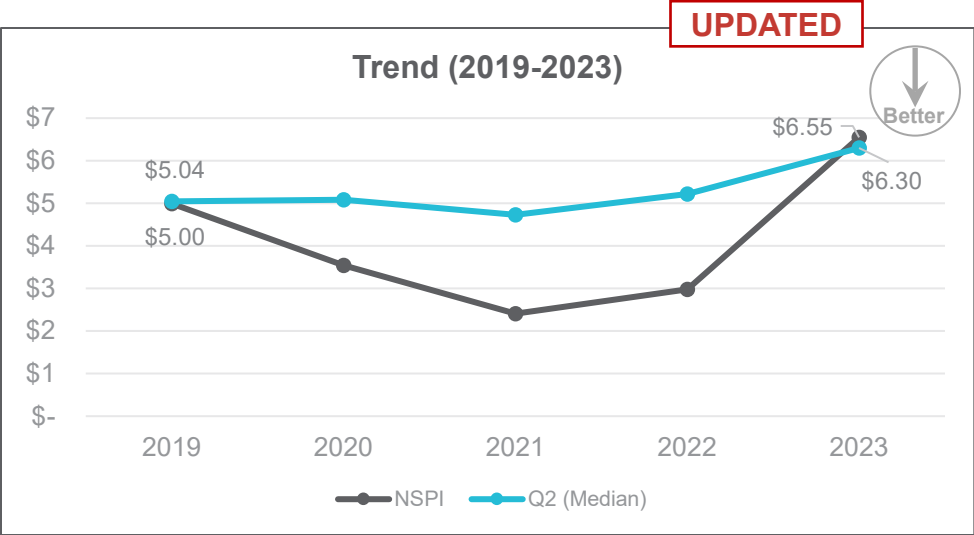
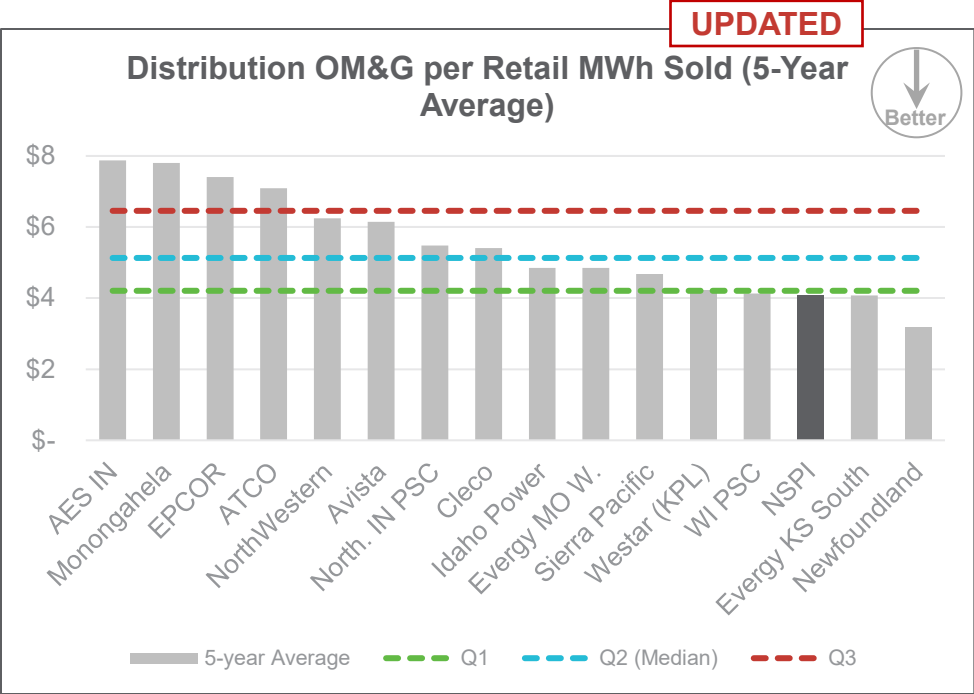
Observations

- On a 5-year average basis, NSPI Distribution OM&G per Retail Customer is first quartile and second lowest among peers
- NSPI Distribution OM&G per Retail Customer increased 26% from 2019 to 2023 (5.9% CAGR) while the peer median Distribution OM&G per Retail Customer **decreased 4%** **increased 2%** over the same timeframe **(-1.1% CAGR) (0.6% CAGR)**
- NSPI Distribution OM&G increased 32% in nominal terms from 2019 to 2023 (7.2% CAGR) while the peer median Distribution OM&G **increased 2.5%** **decreased 1%** over the same timeframe **(0.6% CAGR) (-0.2% CAGR)**
- **Both NSPI and the peer median** number of Retail Customers increased 5% over the period 2019 to 2023 (1.2% CAGR) **while the peer median number of Retail Customers increased 2% (0.4%) over the same timeframe**

Factors Contributing to Performance

- The uptick in NSPI Distribution OM&G per Retail Customer in 2019 is primarily the result of increased spending related to storms, including the impact of Hurricane Dorian and the forestry ROW clearing program. Similarly, NSPI had elevated storm restoration expenses in 2023 at \$44M
- In addition, Distribution OM&G expense increased in 2023 due to customer growth, increased investment in reliability and significant growth in customer requested work

TD4 – Distribution OM&G per Retail MWh Sold



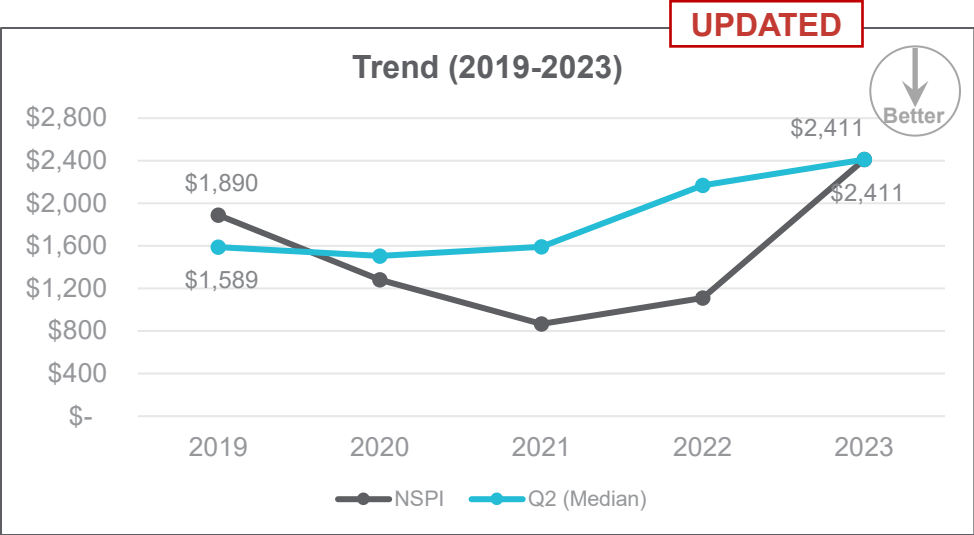
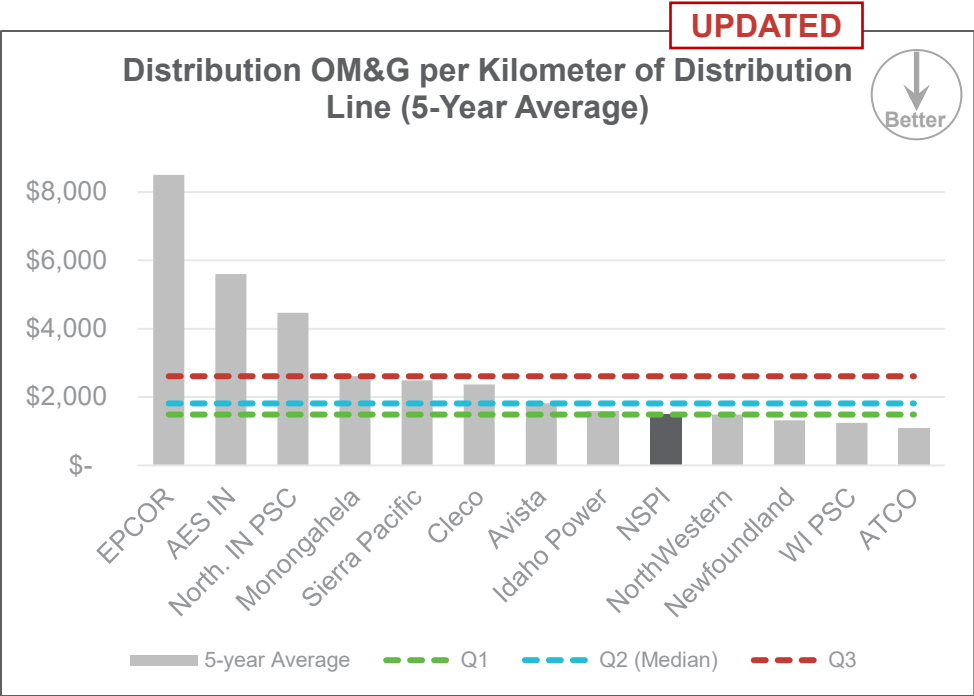
Observations

- On a 5-year average basis, NSPI Distribution OM&G per Retail MWh Sold is first quartile and third lowest among peers
- NSPI Distribution OM&G per Retail MWh Sold increased 31% from 2019 to 2023 (7.0% CAGR) while the peer median Distribution OM&G per Retail MWh Sold increased ~~25%~~ ~~26%~~ over the same timeframe (~~5.7% CAGR~~) (~~5.9% CAGR~~)
- NSPI Distribution OM&G per Retail MWh Sold was in line with the peer median value in 2019 and ~~4% higher in 2023~~ (~~0.5% higher~~), but significantly lower than the peer median in 2020 (~~30%~~ ~~31%~~ lower), 2021 (~~49%~~ ~~51%~~ lower), and 2022 (~~43%~~ ~~47%~~ lower)
- NSPI Distribution OM&G increased 32% in nominal terms from 2019 to 2023 (7.2% CAGR) while the peer median Distribution OM&G ~~increased 2.5%~~ ~~decreased 1%~~ over the same timeframe (~~0.6% CAGR~~) (~~-0.2% CAGR~~)
- NSPI Retail MWh Sold increased slightly by 1% (0.2% CAGR) from 2019 to 2023 while the peer median Retail MWh Sold ~~decreased 0.9%~~ ~~increased 3%~~ over the same timeframe (~~-0.2% CAGR~~) (~~0.7% CAGR~~)

Factors Contributing to Performance

- The uptick in NSPI Distribution OM&G per Retail MWh Sold in 2019 is primarily the result of increased spending related to storms, including the impact of Hurricane Dorian and the forestry ROW clearing program
- In addition, Distribution OM&G expense increased in 2023 due to customer growth, increased investment in reliability and significant growth in customer requested work

TD5 – Distribution OM&G per Km of Distribution Line



Observations

- On a 5-year average basis, NSPI Distribution OM&G per Kilometer of Distribution Line is **at the first/second quartile line and third lowest among peers**
- NSPI Distribution OM&G per Kilometer of Distribution Line increased 28% from 2019 to 2023 (6.3% CAGR) while the peer median OM&G per Kilometer of Distribution Line increased **52% 43%** over the same timeframe (**11.0% CAGR**) (**9.3% CAGR**)
- NSPI Distribution OM&G increased 32% in nominal terms from 2019 to 2023 (7.2% CAGR) while the peer median Distribution OM&G **increased 2.5% decreased 1%** over the same timeframe (**0.6% CAGR**) (**-0.2% CAGR**)
- NSPI Kilometers of Distribution Line increased 3.5% from 2019 to 2023 (0.9% CAGR) while the peer median Kilometers of Distribution Line decreased **31% 5.4%** over the same timeframe (**-9.0% CAGR**) (**-1.4% CAGR**)

Factors Contributing to Performance

- The uptick in NSPI Distribution OM&G per kilometer of Distribution Line in 2019 is primarily the result of increased spending related to storms, including the impact of Hurricane Dorian and the forestry ROW clearing program
- In addition, Distribution OM&G expense increased in 2023 due to customer growth, increased investment in reliability and significant growth in customer requested work

Summary Observations

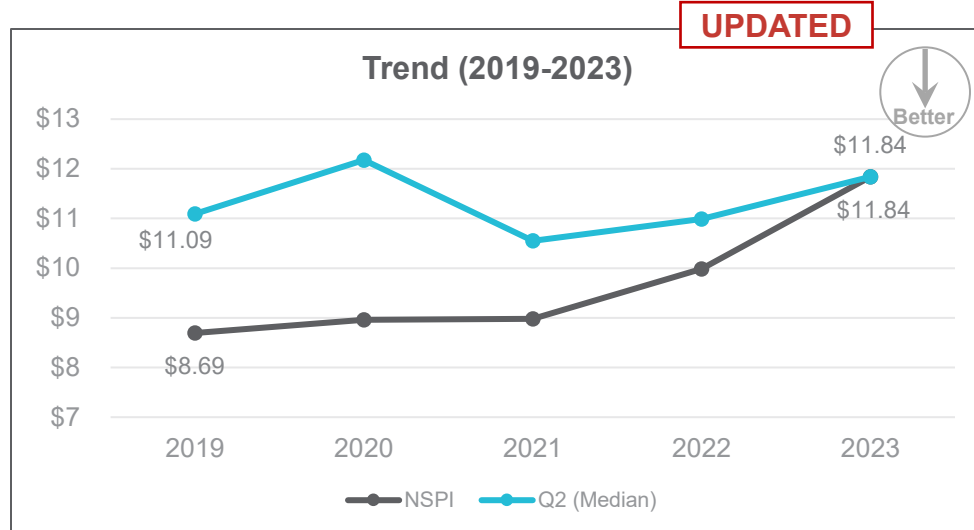
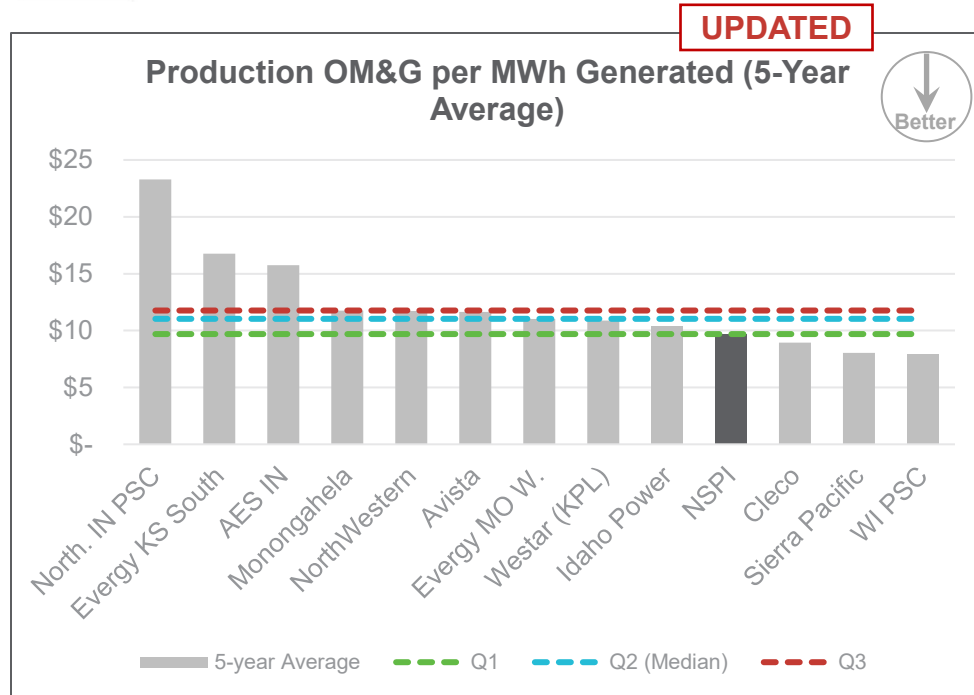
- Transmission and Distribution OM&G costs typically include the cost of operating and maintaining utility transmission and distribution substations, overhead lines and structures, underground lines, and line transformers
- NSPI Transmission ~~and Distribution~~ OM&G costs are ~~both~~ first quartile in the peer group on a per Retail MWh Sold ~~and~~, per Kilometer of Transmission/~~Distribution~~ Line, ~~and per Retail Customer~~ basis
- NSPI Distribution OM&G costs are first quartile in the peer group on a per Retail Customer and per Retail MWh Sold basis, and at the first/second quartile line in the peer group on a per Kilometer of Distribution Line basis
- NSPI widened its positive gap in the Distribution OM&G metrics through 2021, but this gap has since ~~closed~~ ~~narrowed~~ as NSPI's Distribution OM&G expenses grew faster than its peers since 2021. NSPI had increased storm expenses in 2023. In addition, Distribution OM&G expense increased in 2023 due to customer growth, increased investment in reliability and significant growth in customer requested work



Power Production Metrics



PP1 – Production OM&G per MWh Generated



Observations

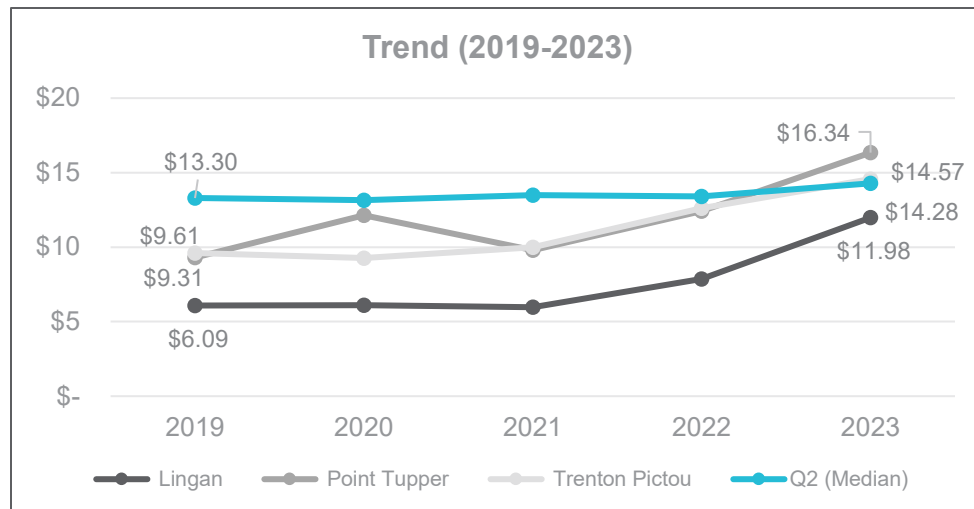
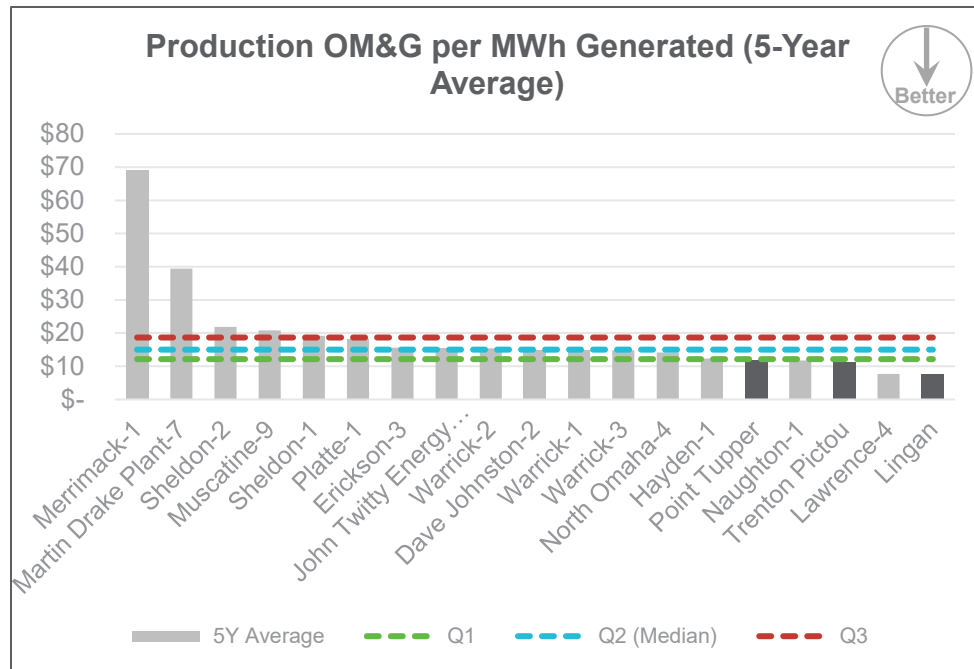
- On a 5-year average basis, NSPI Production OM&G* per MWh Generated is **at the first/second quartile line and third lowest among peers**
- NSPI Production OM&G per MWh Generated increased 36% from 2019 to 2023 (8.0% CAGR) while the peer median Production OM&G per MWh Generated increased **7% 13%** over the same timeframe (**1.6% CAGR**) (**3.0% CAGR**)
- NSPI Production OM&G increased 10% in nominal terms from 2019 to 2023 (2.5% CAGR) while the peer median Production OM&G decreased **7% (-1.9% CAGR)** **5% (-1.3% CAGR)** over the same timeframe
- NSPI MWh Generated was 19% lower in nominal terms in 2023 than in 2019 while the peer median MWh Generated was **18% 21%** lower

Factors Contributing to Performance

- Cost increases can be attributed to several key factors. First, the adoption of unit flexible operations has led to higher operational costs due to the increased frequency of unit startups and shutdowns. Second, environmental compliance requirements have contributed to reduced operational efficiency, as generating less energy inherently results in less efficient unit performance

*Excludes fuel and purchased power costs.

PP2-CoalST – Production OM&G per MWh Generated

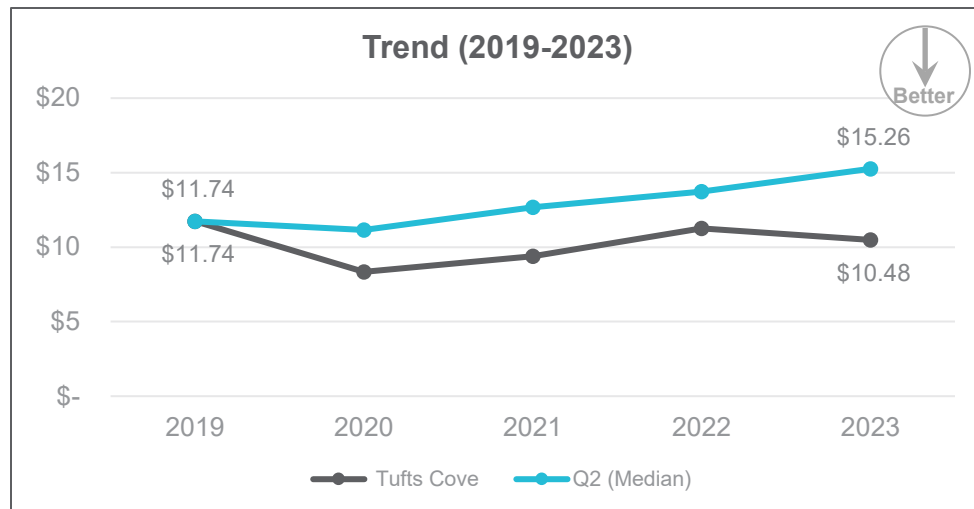
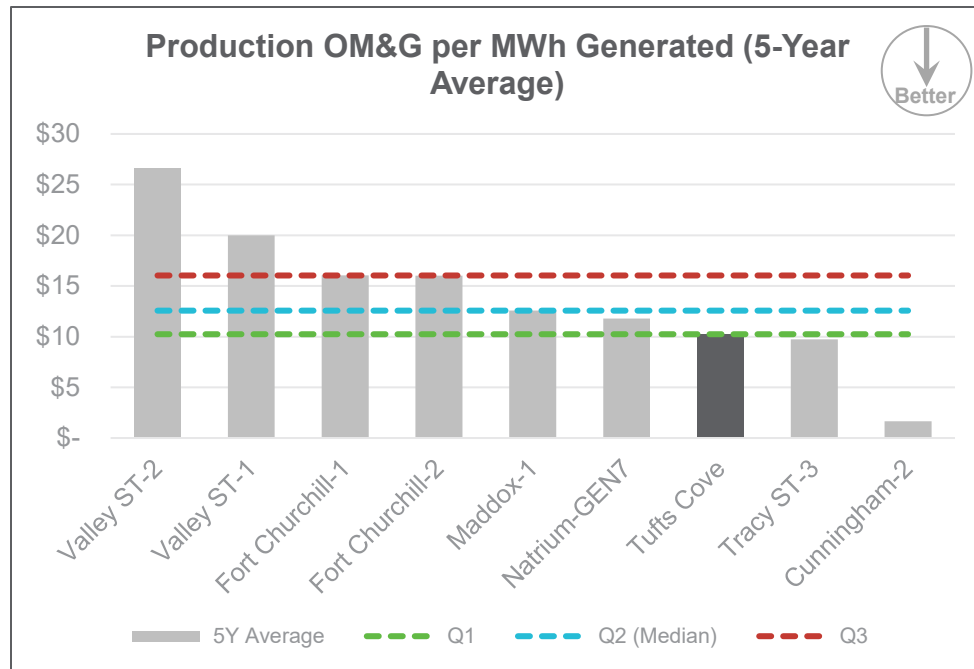


Observations

- On a 5-year average basis, NSPI Production OM&G* per MWh Generated for Trenton Pictou, Point Tupper, and Lingan are among the five lowest in the peer group
- Production OM&G per MWh Generated increased 97% for Lingan (18.4% CAGR), 76% for Point Tupper (15.1% CAGR), and 52% for Trenton Pictou (11.0% CAGR) from 2019 to 2023. The peer group median Production OM&G per MWh Generated increased 7.4% over the same timeframe
- Between 2019 and 2023, Production OM&G increased 16% for Lingan (3.9% CAGR), decreased 11% for Trenton Pictou (-2.9% CAGR), and remained consistent for Point Tupper
- MWh Generated was 41% lower for Lingan, 43% lower for Point Tupper, and 41% lower for Trenton Pictou in 2023 than in 2019

*Excludes fuel and purchased power costs. NSPI does not track OM&G on a unit-by-unit basis, so NSPI plant-level costs are shown compared to peer unit-level costs. Erickson-3 was retired in 2022 and therefore 2023 data is not available. Martin Drake Plant-7 was permanently decommissioned in 2022 and therefore 2023 data is not available.

PP2-HFOT – Production OM&G per MWh Generated

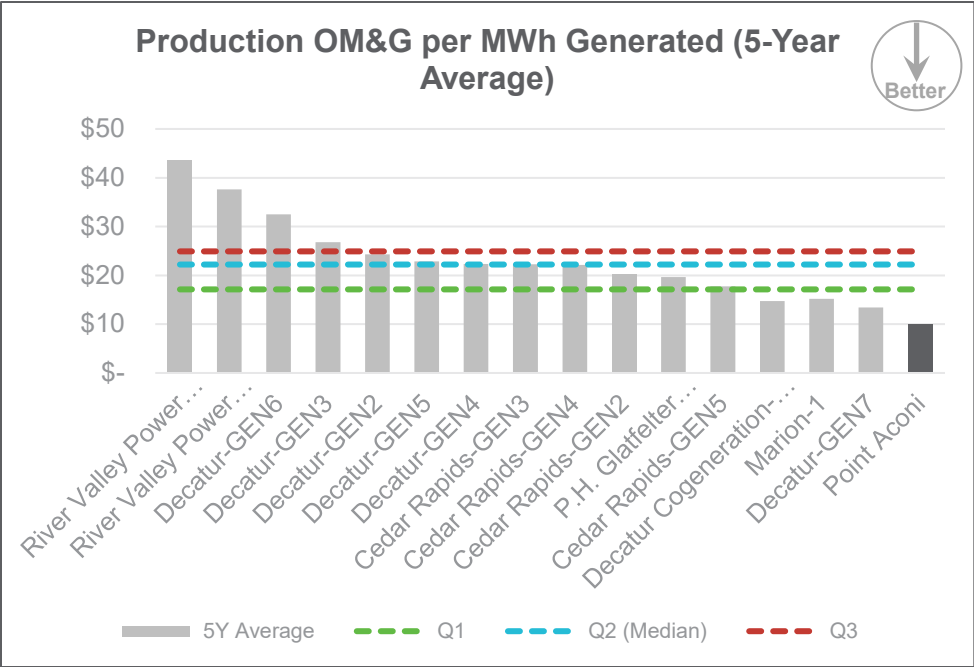


Observations

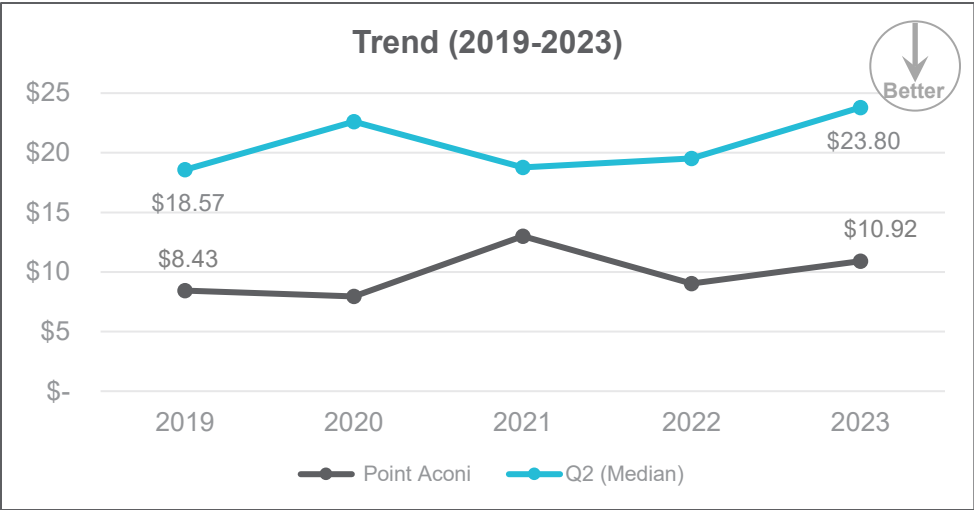
- On a 5-year average basis, Tufts Cove has the third lowest Production OM&G* per MWh Generated in the peer group
- Tufts Cove Production OM&G per MWh Generated decreased 11% from 2019 to 2023 (-2.8% CAGR). The median Production OM&G per MWh Generated for the peer group increased 30% over the same timeframe (6.8% CAGR)
- Tufts Cove Production OM&G increased 40% between 2019 and 2023 (8.8% CAGR) while the MWh Generated was 57% higher in 2023 than in 2019

*Excludes fuel and purchased power costs. NSPI does not track OM&G on a unit-by-unit basis, so NSPI plant-level costs are shown compared to peer unit-level costs.

PP2-ACFB – Production OM&G per MWh Generated

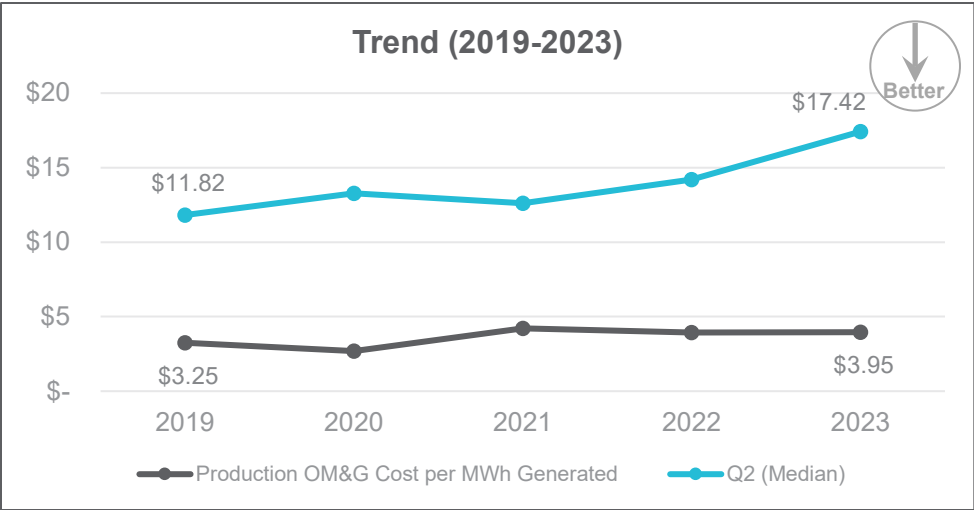
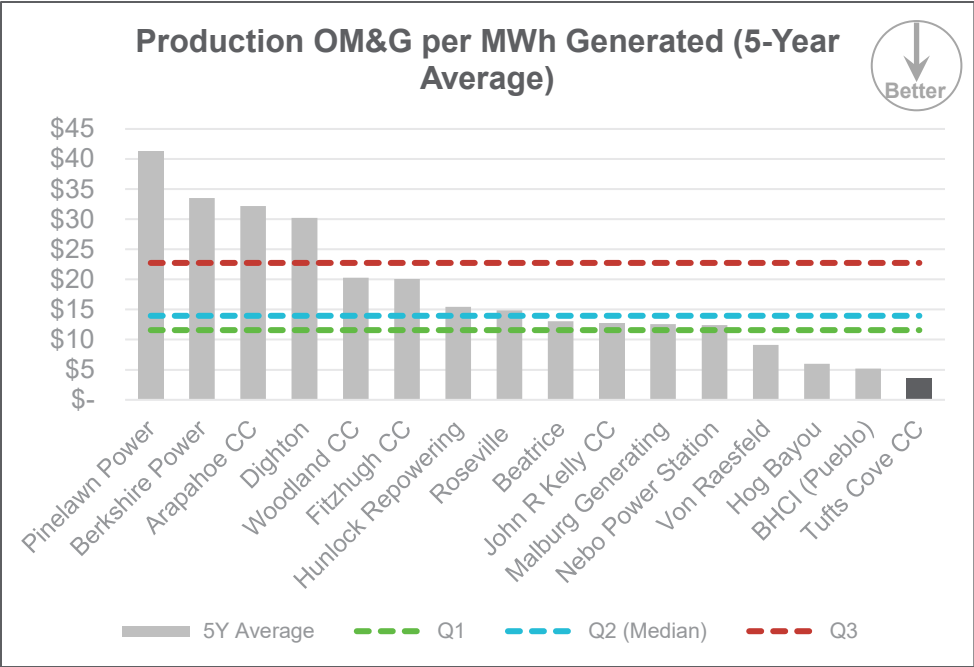


- Observations**
- On a 5-year average basis, Point Aconi Production OM&G* per MWh Generated is the lowest in the peer group
 - Point Aconi Production OM&G per MWh Generated increased 30% from 2019 to 2023 (6.7% CAGR) while the median Production OM&G per MWh Generated for the peer group increased 28% over the same timeframe (6.4% CAGR)
 - Point Aconi Production OM&G increased 6% between 2019 and 2023 (1.4% CAGR) while the MWh Generated was 18% lower in 2023 than in 2019



*Excludes fuel and purchased power costs. NSPI does not track OM&G on a unit-by-unit basis, so NSPI plant-level costs are shown compared to peer unit-level costs.

PP2-CC – Production OM&G per MWh Generated



Observations

- On a 5-year average basis, Tufts Cove combined cycle plant Production OM&G* per MWh Generated is the lowest in the peer group
- Production OM&G per MWh Generated for the Tufts Cove combined cycle plant increased 22% from 2019 to 2023 (5.0% CAGR) while the median Production OM&G per MWh Generated for the peer group increased 47% over the same timeframe (10.2% CAGR)
- Tufts Cove combined cycle plant Production OM&G increased 54% between 2019 and 2023 (11.4% CAGR) while the MWh Generated was 27% higher in 2023 than in 2019

*Excludes fuel and purchased power costs. NSPI does not track OM&G on a unit-by-unit basis, so NSPI plant-level costs are shown compared to peer unit-level costs.

Summary Observations

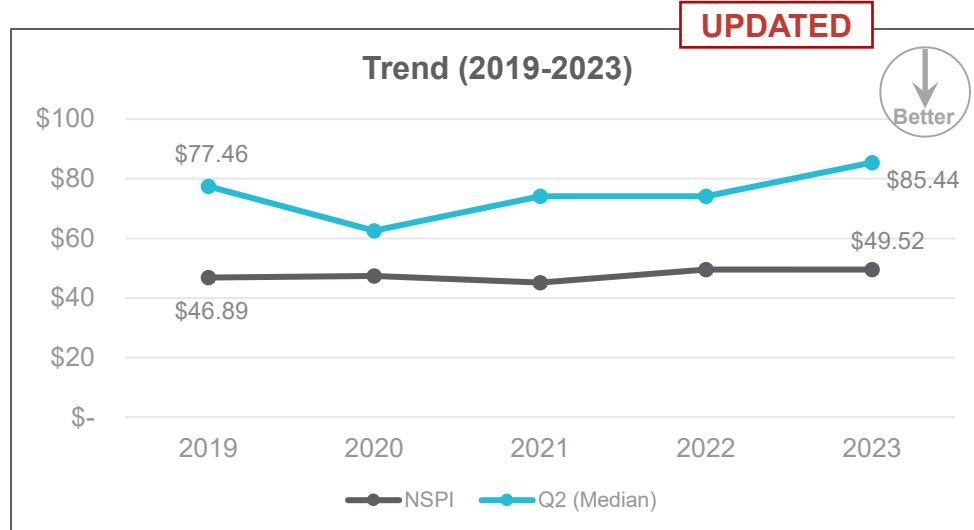
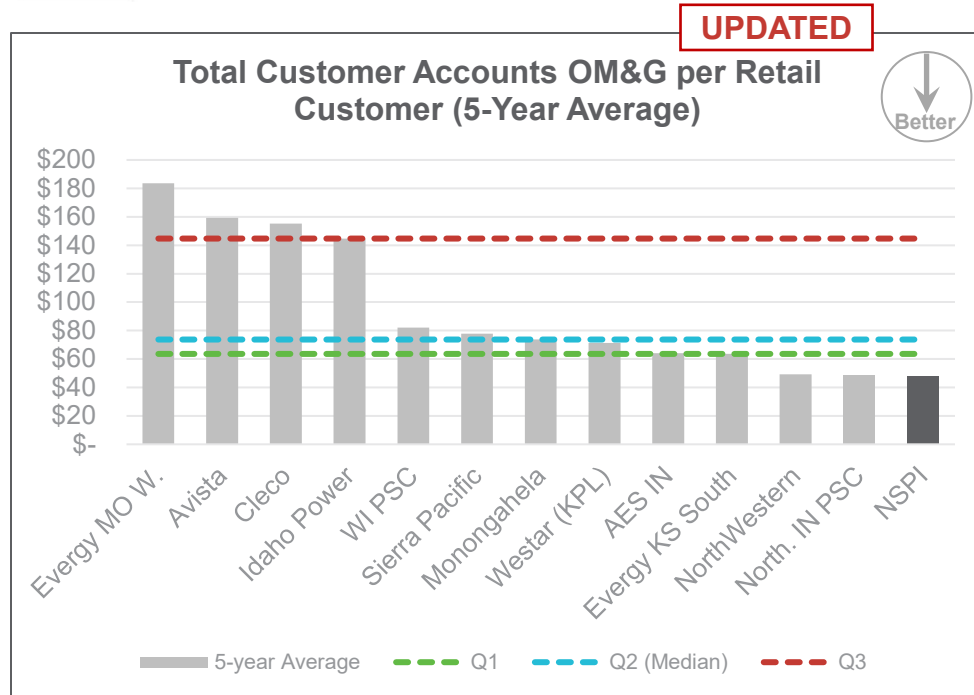
- Production OM&G typically includes labor and expenses incurred in the operation and maintenance of steam power generating stations, including operating prime movers, generators, and their auxiliary apparatus, switch gear and other electric equipment to the points where electricity leaves for conversion for transmission or distribution, excluding the cost of fuel and purchased power
- NSPI Production OM&G per MWh Generated at an enterprise-level and at the plant-level compares favorably to peers, ranking ~~in the first quartile and~~ among the lowest compared to peers for all metrics. **NSPI Production OM&G per MWh Generated ranks at the first/second quartile line at an enterprise-level and in the first quartile at the plant level**
- The enterprise-level Production OM&G per MWh Generated is trending higher due to increases at Trenton Pictou, Point Tupper, and Lingan



Customer Accounts Metrics



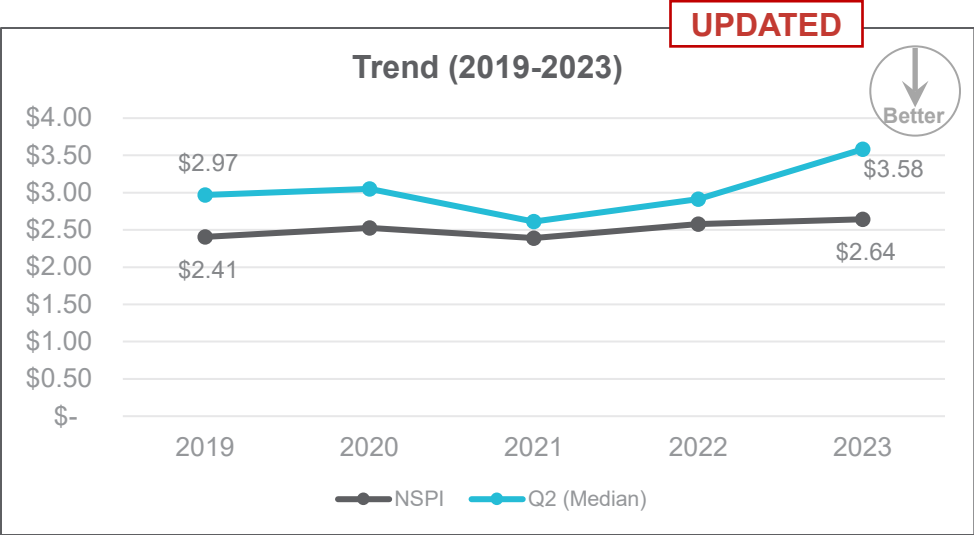
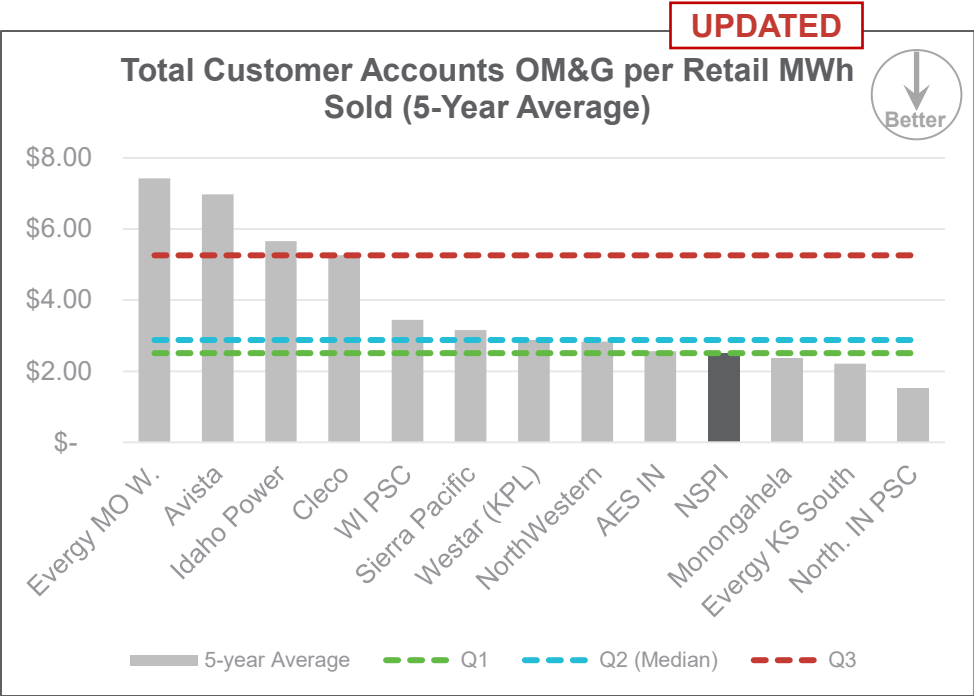
CS1 – Total Customer Accounts OM&G per Retail Customer



Observations

- On a 5-year average basis, NSPI Total Customer Accounts OM&G per Retail Customer is first quartile and **second** lowest among peers
- NSPI Total Customer Accounts OM&G per Retail Customer increased 6% from 2019 to 2023 (1.4% CAGR) while the peer median Customer Accounts OM&G per Retail Customer increased **10% 9%** over the same timeframe (**2.5% CAGR**) (~~2.2% CAGR~~)
- NSPI Total Customer Accounts OM&G increased 11% in nominal terms from 2019 to 2023 (2.6% CAGR) while the peer median Total Customer Service OM&G **increased 17%** **decreased 14%** over the same timeframe (**4.0% CAGR**) (~~3.8% CAGR~~)
- ~~Both NSPI and the peer median~~ number of Retail Customers increased 5% over the period 2019 to 2023 (1.2% CAGR) **while the peer median number of Retail Customers increased 2% (0.4%) over the same timeframe**

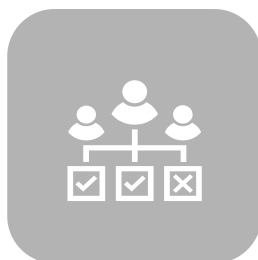
CS2 – Total Customer Accounts OM&G per Retail MWh Sold



- ### Observations
- On a 5-year average basis, NSPI Total Customer Accounts OM&G per Retail MWh Sold is **just within at the first/second quartile line** compared to peers
 - NSPI Total Customer Accounts OM&G per Retail MWh Sold increased 10% from 2019 to 2023 (2.4% CAGR) while the peer median value increased **21% 16%** over the same timeframe (**4.8% CAGR**) (**3.7% CAGR**)
 - NSPI Total Customer Accounts OM&G increased 11% in nominal terms from 2019 to 2023 (2.6% CAGR) while the peer median Total Customer Service OM&G **increased decreased 17% 14%** over the same timeframe (**4.0% CAGR**) (**-3.8% CAGR**)
 - NSPI Retail MWh Sold increased 1% from 2019 to 2023 (0.2% CAGR) while the peer median Retail MWh Sold **decreased 0.9% increased 3%** over the same timeframe (**-0.2% CAGR**) (**0.7% CAGR**)

Summary Observations

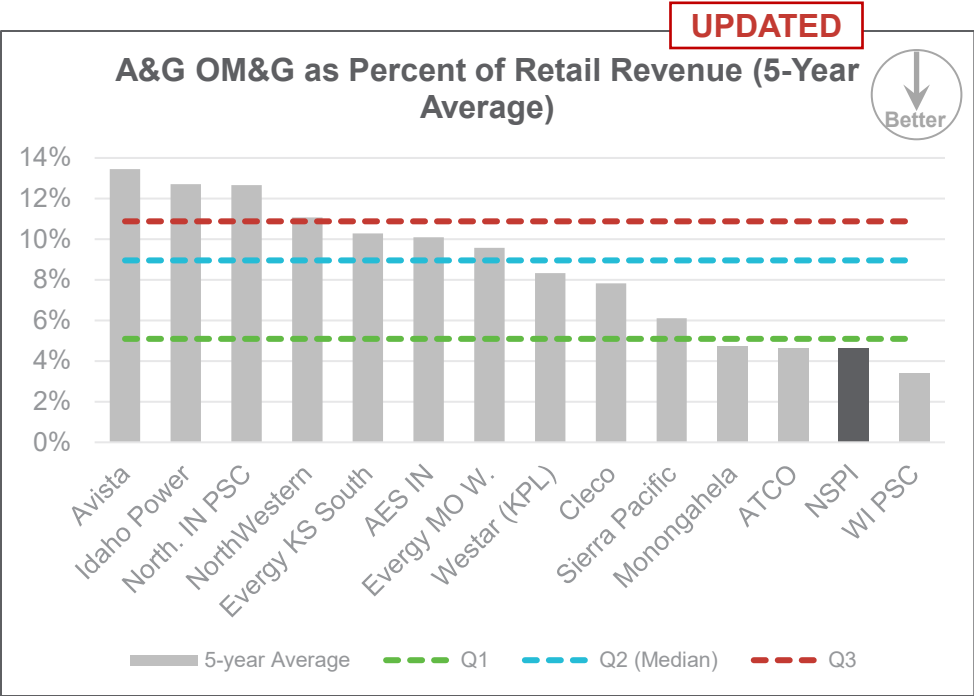
- Total Customer Accounts OM&G includes Customer Accounts, Customer Service and Information, and Sales costs
 - Customer Accounts typically includes the costs incurred in the general direction and supervision of customer accounting and collecting activities, including meter reading, customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints, as well as uncollectible accounts (bad debt) expense
 - Customer Service and Information typically includes costs to encourage safe and efficient use of the utility's service, to encourage conservation of the utility's service, and to assist customers in answering specific inquiries as to the proper and economic use of the utility's service and the customer's equipment utilizing the service
 - Sales includes the costs incurred in the general direction and supervision of sales activities, including promotional, demonstrating, and selling activities, as well as advertising, to promote or retain the use of utility services by current and prospective customers
- NSPI Customer Accounts OM&G per Retail Customer and per Retail MWh Sold are **in the first quartile and** at the first/second quartile line, **respectively**, compared to the peer group and have increased at a slower rate than peers



Administrative & General Metrics



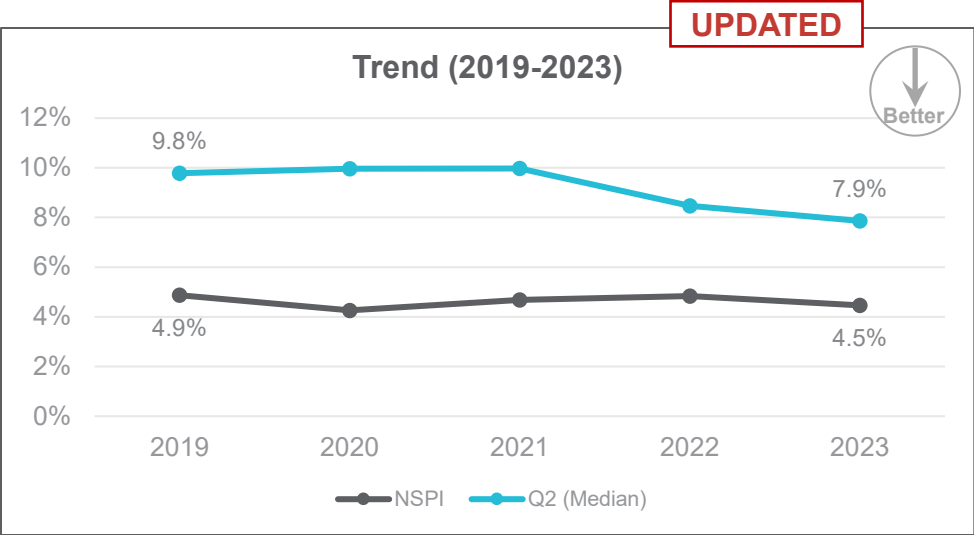
AG1 – A&G OM&G as a Percent of Retail Revenue



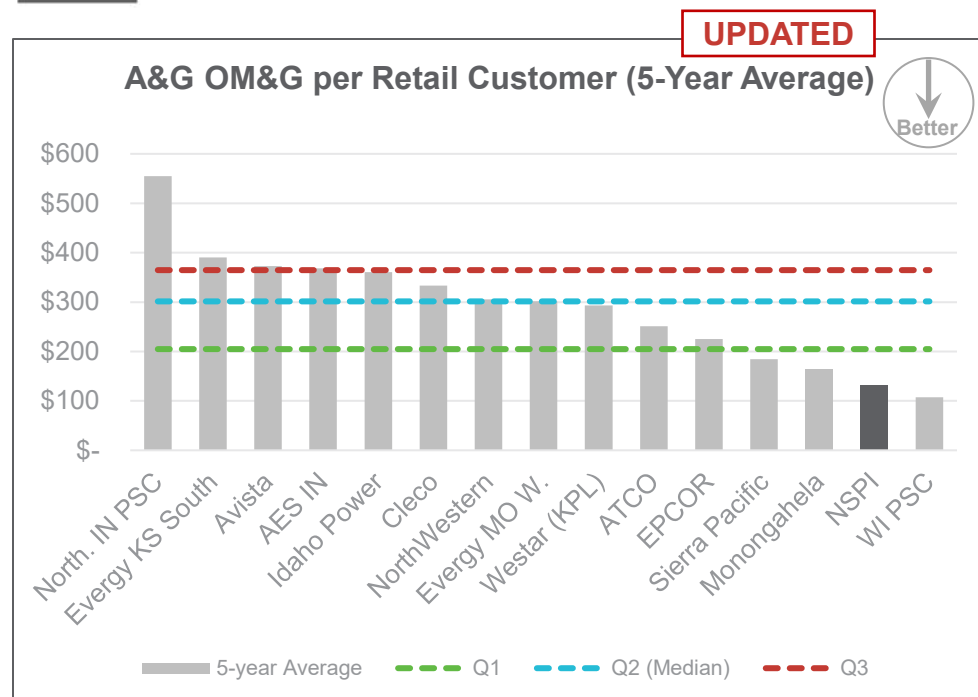
Observations

- NSPI A&G OM&G as Percent of Retail Revenue is in the first quartile of the peer group
- NSPI A&G OM&G as Percent of Retail Revenue decreased 0.4 percentage points from 2019 to 2023 while the peer median A&G OM&G as Percent of Retail Revenue decreased ~~1.9~~ 1.7 percentage points over the same timeframe
- Both NSPI and the peer median A&G OM&G costs increased 7.6% in nominal terms from 2019 to 2023 (1.8% CAGR) while the peer median A&G OM&G costs increased 18% over the same timeframe (~~4.3% CAGR~~)
- NSPI Retail Revenue increased 17% in nominal terms from 2019 to 2023 (4.1% CAGR) while the peer median Retail Revenue increased ~~14%~~ 21% over the same timeframe (~~3.4% CAGR~~) (4.8% CAGR)

*The value shown for ATCO uses selling, general and administrative costs

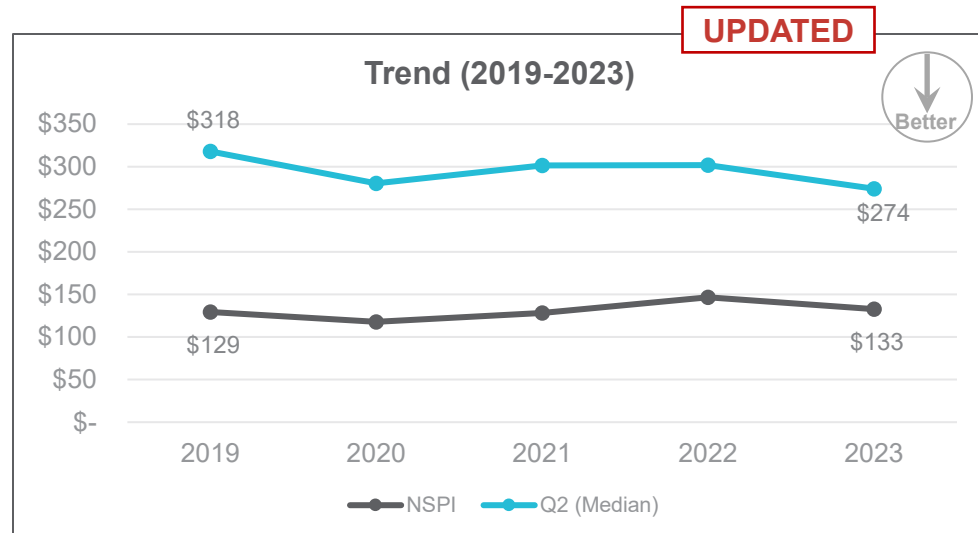


AG2 – A&G OM&G per Retail Customer



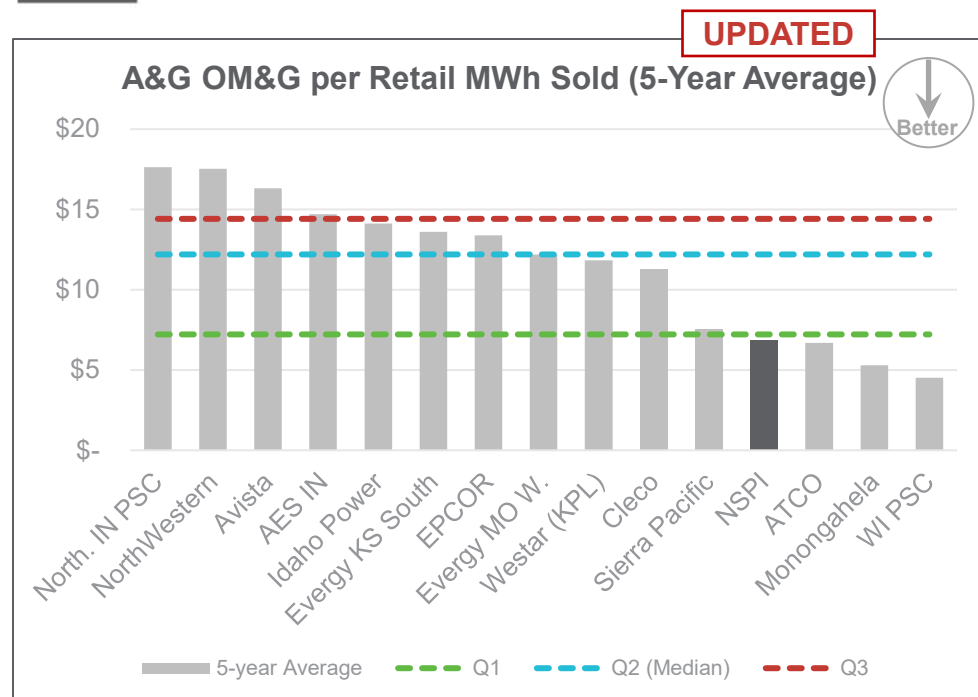
Observations

- NSPI A&G OM&G per Retail Customer is first quartile and second lowest among peers
- NSPI A&G OM&G per Retail Customer increased 3% from 2019 to 2023 (0.7% CAGR) while the peer median A&G OM&G per Retail Customer decreased **14%** ~~1%~~ over the same timeframe **(-3.6% CAGR)** ~~(-0.2% CAGR)~~
- **Both NSPI and the peer median A&G OM&G costs increased 7.6% in nominal terms from 2019 to 2023 (1.8% CAGR) while the peer median A&G OM&G costs increased 18% over the same timeframe (4.3% CAGR)**
- ~~Both NSPI and the peer median~~ number of Retail Customers increased 5% over the period 2019 to 2023 (1.2% CAGR) while the peer median number of Retail Customers increased 2% (0.4%) over the same timeframe



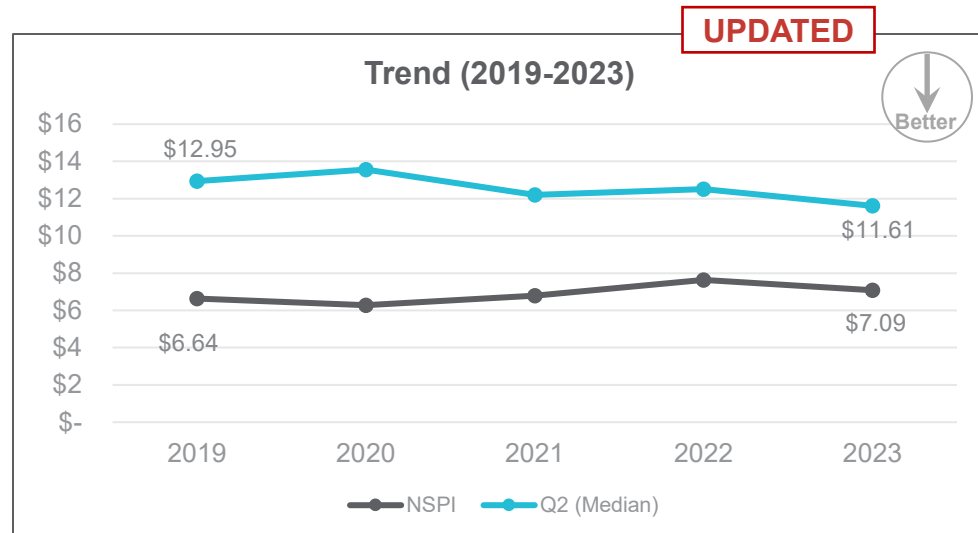
*The value shown for ATCO uses selling, general and administrative costs

AG3 – A&G OM&G per Retail MWh Sold



Observations

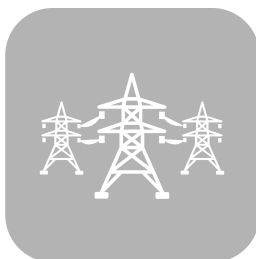
- NSPI A&G OM&G per Retail MWh Sold is **in at** the first/~~second~~ quartile ~~line~~ within the peer group
- NSPI A&G OM&G per Retail MWh Sold increased 7% from 2019 to 2023 (1.6% CAGR) while the peer median A&G OM&G per Retail MWh Sold decreased **10% 17%** over the same timeframe (**-2.7% CAGR**) (~~-4.5% CAGR~~)
- **Both** NSPI **and the peer median** A&G OM&G costs increased 7.6% in nominal terms from 2019 to 2023 (1.8% CAGR) **while the peer median A&G OM&G costs increased 18% over the same timeframe (4.3% CAGR)**
- NSPI Retail MWh Sold increased 1% from 2019 to 2023 (0.2% CAGR) while the peer median Retail MWh Sold **decreased 0.9% increased 3%** over the same timeframe (**-0.2% CAGR**) (~~0.7% CAGR~~)



*The value shown for ATCO uses selling, general and administrative costs

Summary Observations

- Administrative and General OM&G costs typically include the salaries, bonuses, and other consideration for services of officers, executives, and other employees of the utility properly chargeable to utility operations and not chargeable directly to a particular operating function (e.g., production, transmission, distribution, etc.), office supplies, outside services, property insurance, injuries and damages, regulatory commission expenses, rents and general plant maintenance
- NSPI A&G OM&G costs compare favorably to peers, ranking ~~in at~~ the first/~~second~~ quartile ~~line or better~~ on a per Retail Customer, per Retail Revenue, and per Retail MWh Sold basis
- ~~On a per Retail Revenue and per Retail MWh Sold basis, t~~ The peer group is improving at a faster rate than NSPI

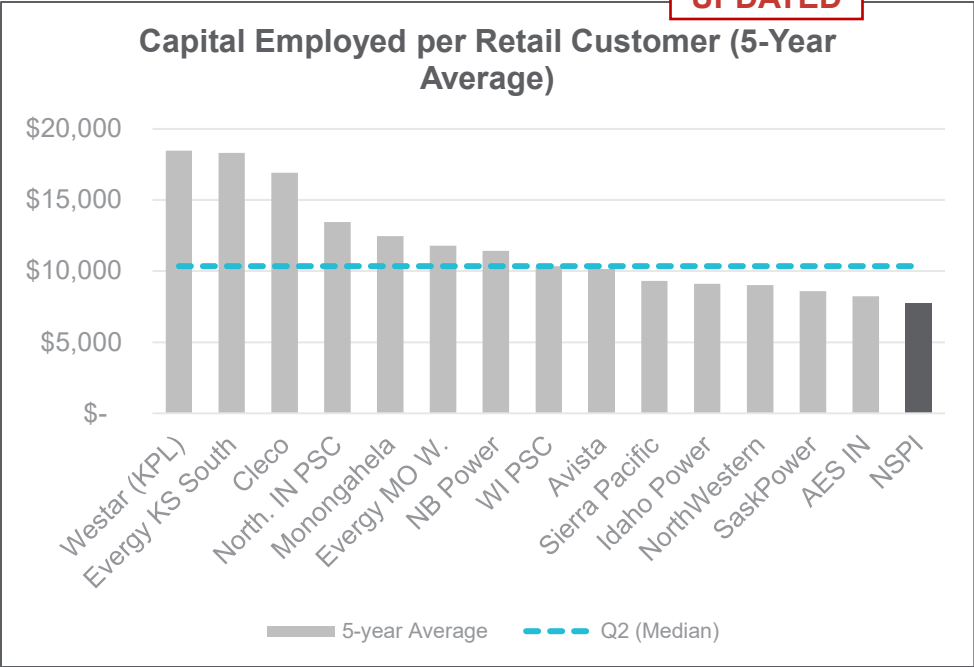


Capital Additions Metrics



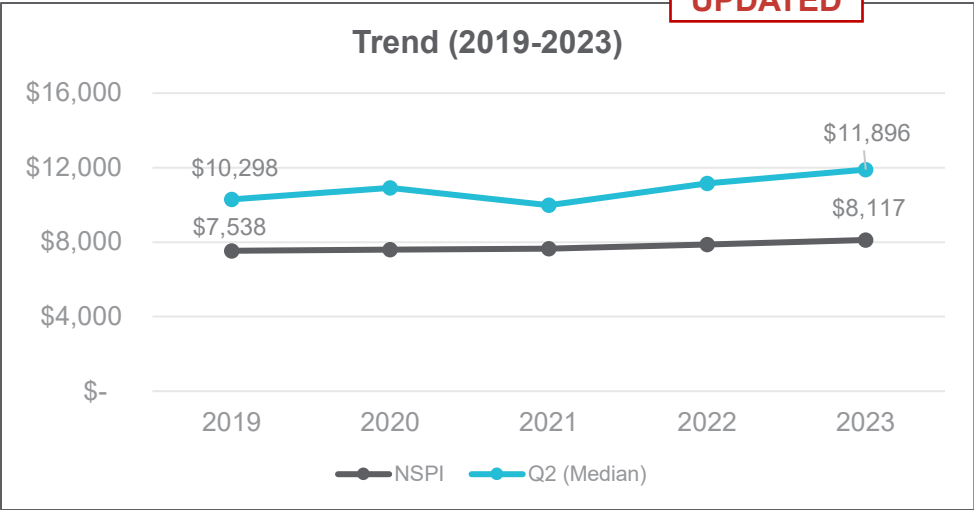
CA1 – Capital Employed per Retail Customer

UPDATED

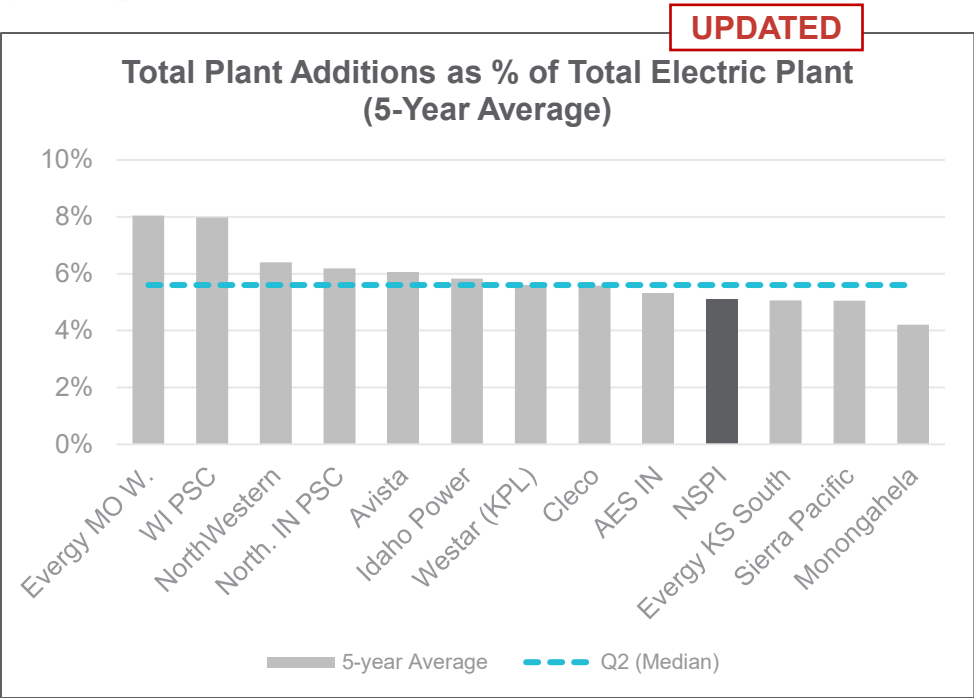


- Observations
- On a 5-year average basis, NSPI Capital Employed (or Net Plant) per Retail Customer **is** lowest of the peer group
 - NSPI Capital Employed per Retail Customer in 2023 was 8% higher than in 2019, while the peer median Capital Employed per Retail Customer was **16% 14%** higher in 2023 than in 2019
 - NSPI Net Plant was 13% higher in nominal terms in 2023 than in 2019 while peer median Net Plant was **12% 23%** higher in 2023 than in 2019
 - ~~Both NSPI and the peer median~~ number of Retail Customers increased 5% over the period 2019 to 2023 (1.2% CAGR) **while the peer median number of Retail Customers increased 2% (0.4%) over the same timeframe**

UPDATED

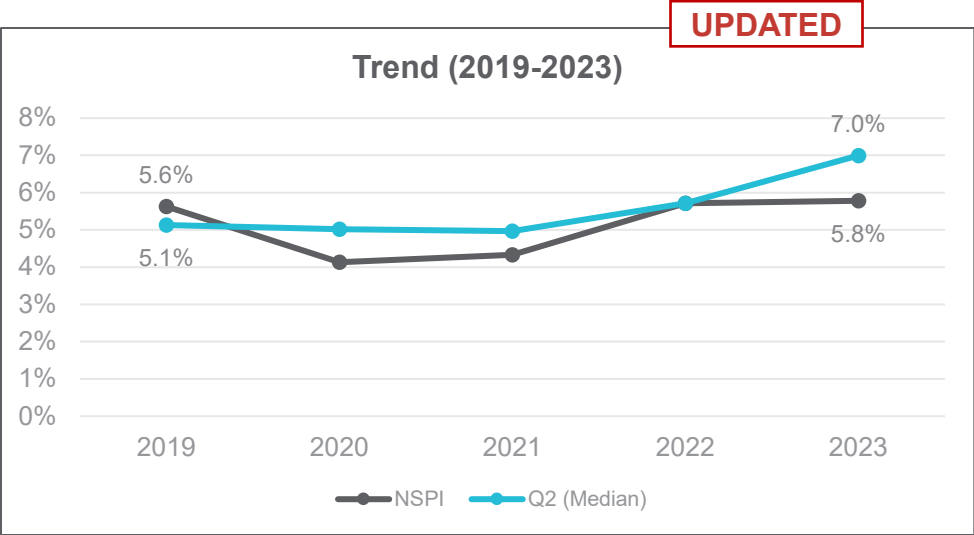


CA2 – Total Plant Additions as % of Total Electric Plant

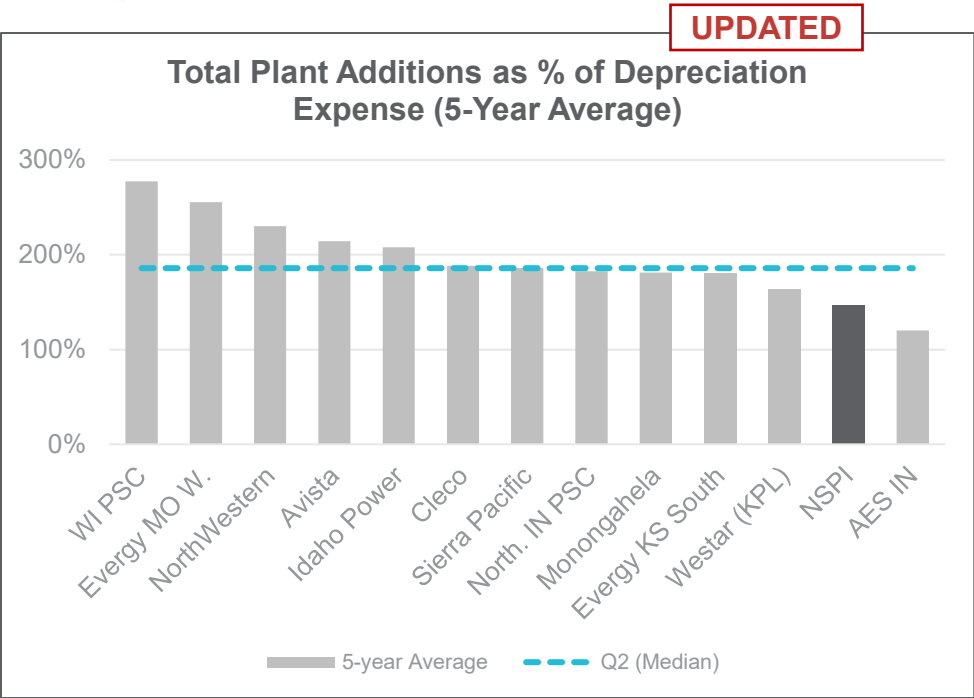


Observations

- On a 5-year average basis, NSPI Total Plant Additions as a Percent of Total Electric Plant is lower than the peer median
- NSPI Total Plant Additions as a Percent of Total Electric Plant decreased by 1.5 percentage points from 2019 to 2020, remained near this level in 2021, and increased back to 2019 levels in 2022 and 2023. The peer median value **increased 1.9 percentage points** was **relatively flat** from 2019 to 2023
- NSPI Total Plant Additions in 2023 were 17% higher in than in 2019 while peer median Total Plant Additions were **31% 4%** higher in 2023 than in 2019
- NSPI Total Electric Plant in 2023 was 14% higher in nominal terms than in 2019 while the peer median Total Electric Plant was **11% 26%** higher in 2023 than in 2019

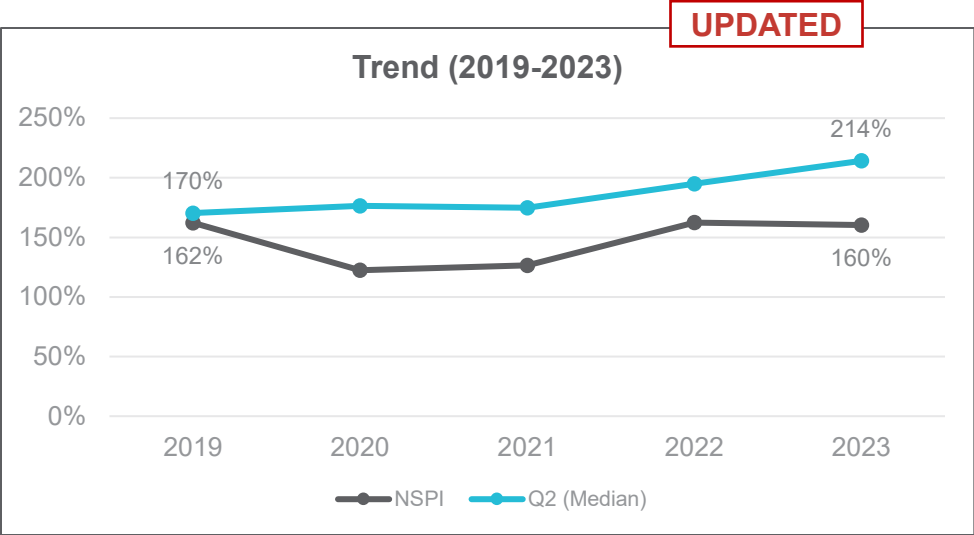


CA3 – Total Plant Additions as % of Depreciation Expense



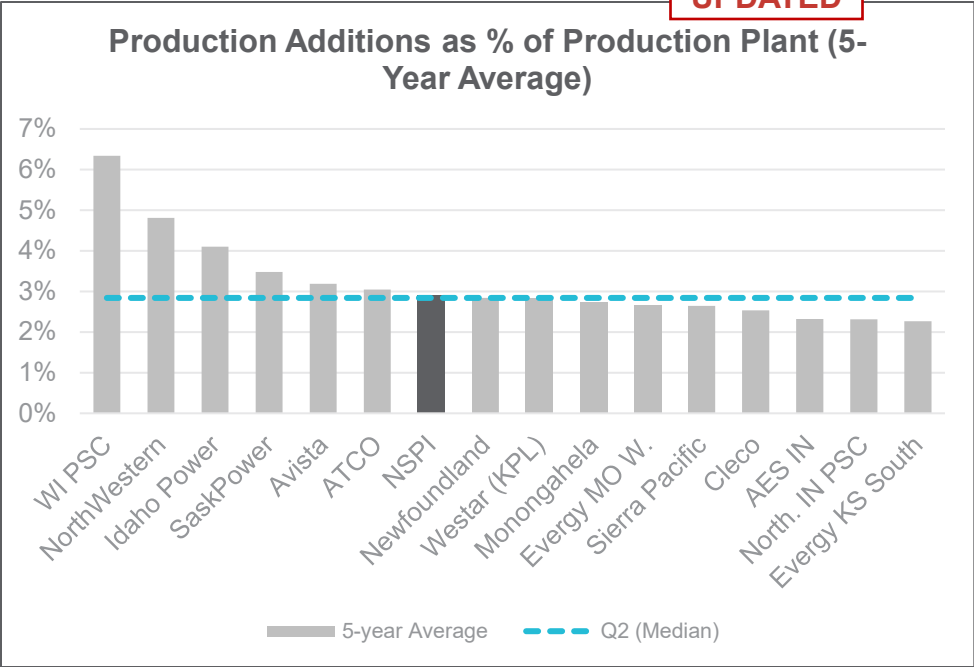
Observations

- On a 5-year average basis, NSPI Total Plant Additions as Percent of Depreciation Expense is below the peer group median and the second lowest among all peers
- NSPI Total Plant Additions as a Percent of Depreciation Expense decreased 40 percentage points in 2020, remained near that level in 2021, and increased back to near 2019 levels in 2022 and 2023. The peer median value increased 44 14 percentage points between 2019 and 2023
- NSPI Total Plant Additions in 2023 were 17% higher than in 2019 while peer median Total Plant Additions were 31% 4% higher in 2023 than in 2019
- Both NSPI and peer median Depreciation Expense in 2023 was 19% higher in nominal terms than in 2019 while the peer median Depreciation Expense was 28% higher in 2023 than in 2019



CA4 – Production Additions as % of Production Plant

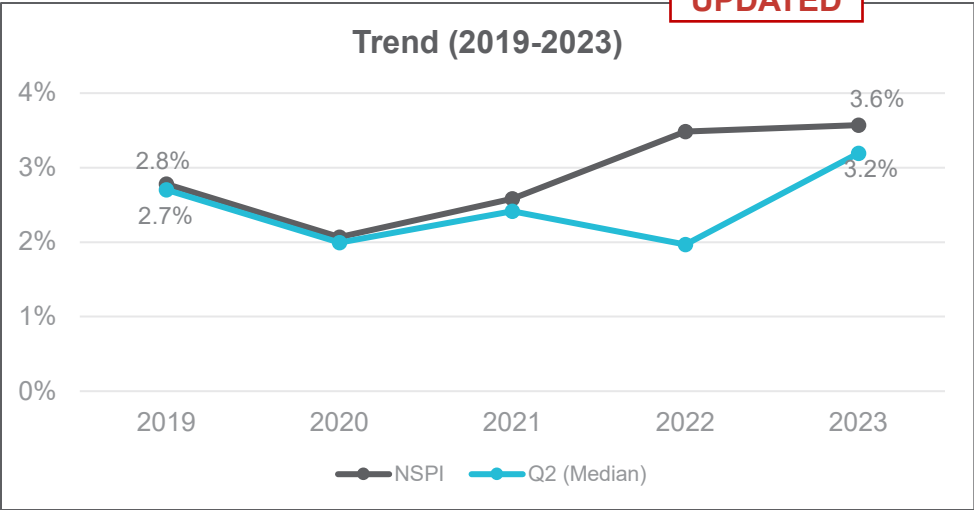
UPDATED



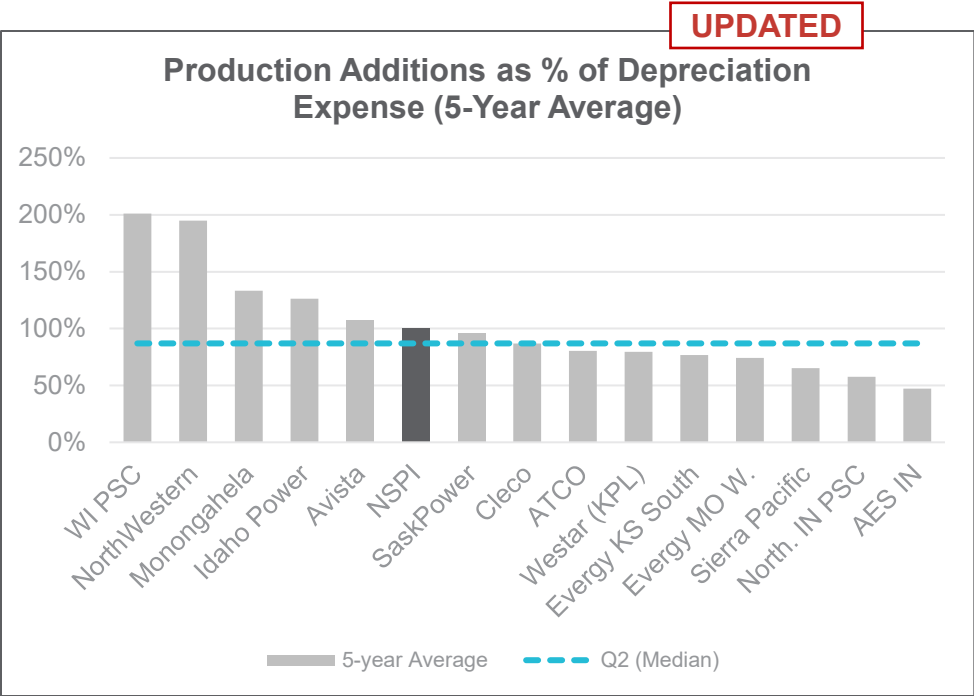
Observations

- On a 5-year average basis, NSPI Production Additions as a Percent of Production Plant are slightly ~~above~~ ~~below~~ the peer group median
- NSPI Production Additions as a Percent of Production Plant increased 1 percentage point from 2019 to 2023. The peer median Production Additions as a Percent of Production Plant ~~increased 0.5 percentage points~~ ~~decreased slightly~~ over the same timeframe
- NSPI Production Additions in 2023 were 37% higher in nominal terms than in 2019 while peer median Production Additions were ~~24% higher~~ ~~42% lower~~ in 2023 than in 2019
- NSPI Production Plant in 2023 was 7% higher in nominal terms than in 2019 while peer median Production Plant was ~~1% 3%~~ higher in 2023 than in 2019

UPDATED

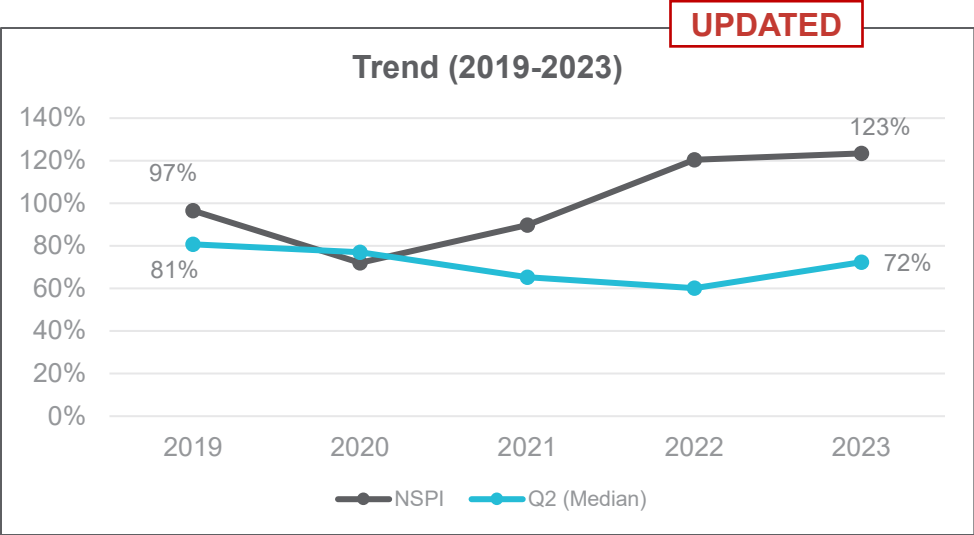


CA5 – Production Additions as % of Depreciation Expense



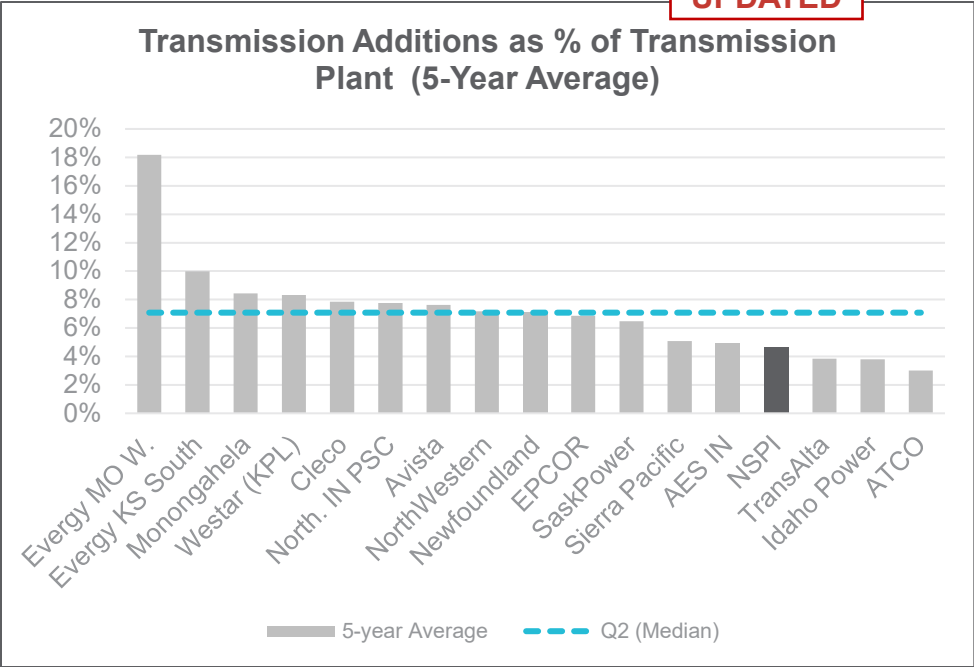
Observations

- On a 5-year average basis, NSPI Production Additions as a Percent of Depreciation Expense is **above slightly below** the peer group median
- NSPI Production Additions as a Percent of Depreciation Expense decreased by 25 percentage points from 2019 to 2020, then increased by 48 percentage points over the next two years before leveling out in 2022 and 2023. The peer median Production Additions as a Percent of Depreciation Expense **decreased 8 increased 4** percentage points from 2019 to 2023
- NSPI Production Additions in 2023 were 37% higher in nominal terms than in 2019 while peer median Production Additions were **24% higher 12% lower** in 2023 than in 2019
- NSPI Production Depreciation Expense in 2023 was 7% higher in nominal terms than in 2019 while the peer median Production Depreciation Expense was 6% lower in 2023 than in 2019



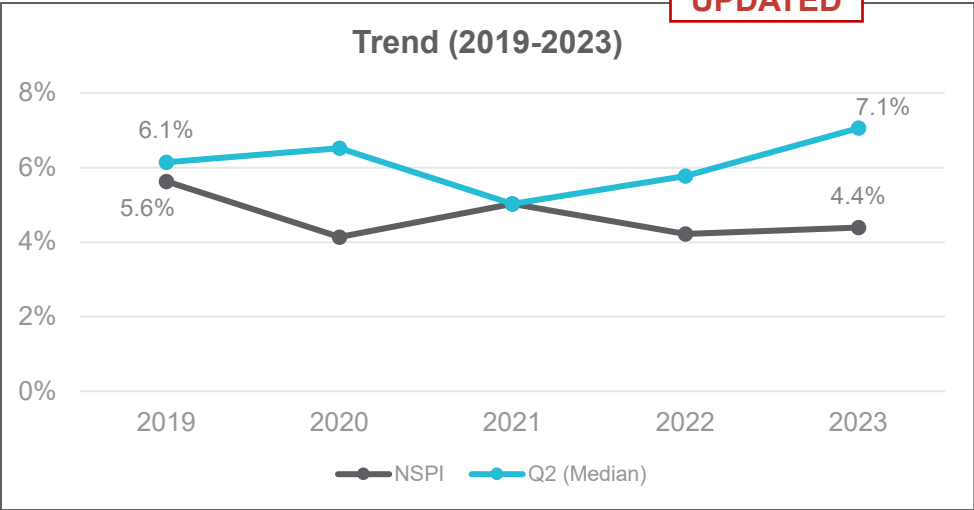
CA6 – Transmission Additions as % of Transmission Plant

UPDATED



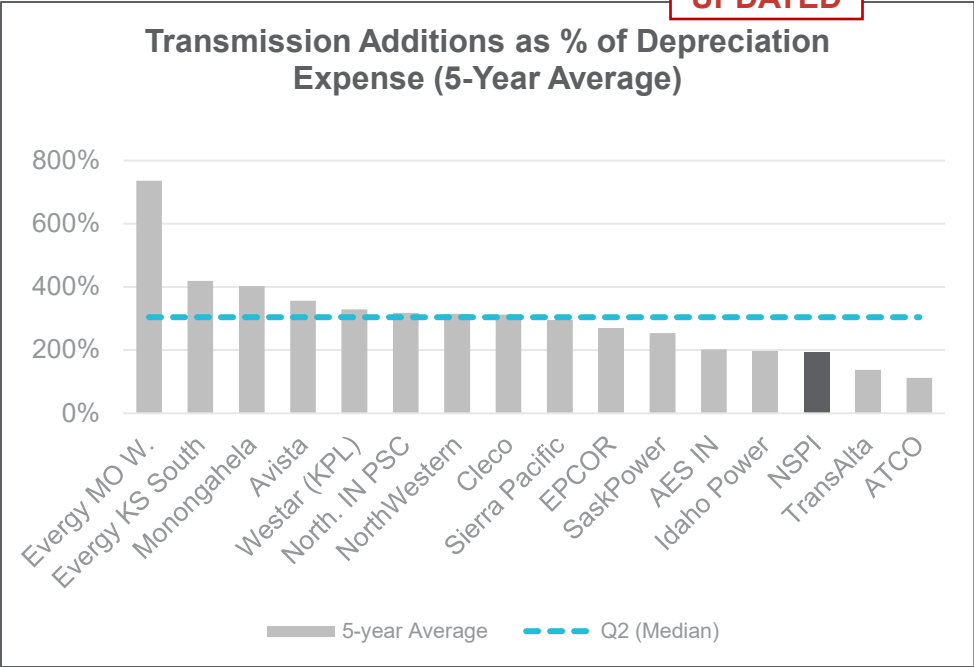
- Observations
- On a 5-year average basis, NSPI Transmission Additions as a Percent of Transmission Plant is below the peer group median and is fourth lowest
 - NSPI Transmission Additions as a Percent of Transmission Plant decreased by just over 1 percentage point between 2019 and 2023. The peer median Transmission Additions as a Percent of Transmission Plant **increased by nearly 1 percentage point decreased by a smaller amount, 0.3 percentage points,** over the same timeframe
 - NSPI Transmission Additions in 2023 were 9% lower than in 2019 while the peer median Transmission Additions were **58% 29%** higher in 2023 than in 2019
 - NSPI Transmission Plant in 2023 was 15% higher in nominal terms than in 2019 while the peer median Transmission Plant was 6% lower in 2023 than in 2019

UPDATED



CA7 – Transmission Additions as % of Depreciation Expense

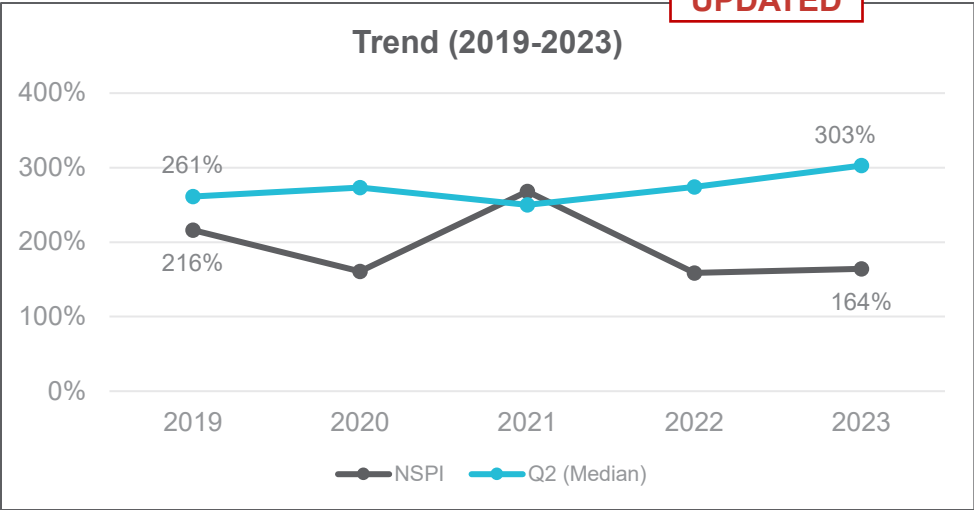
UPDATED



Observations

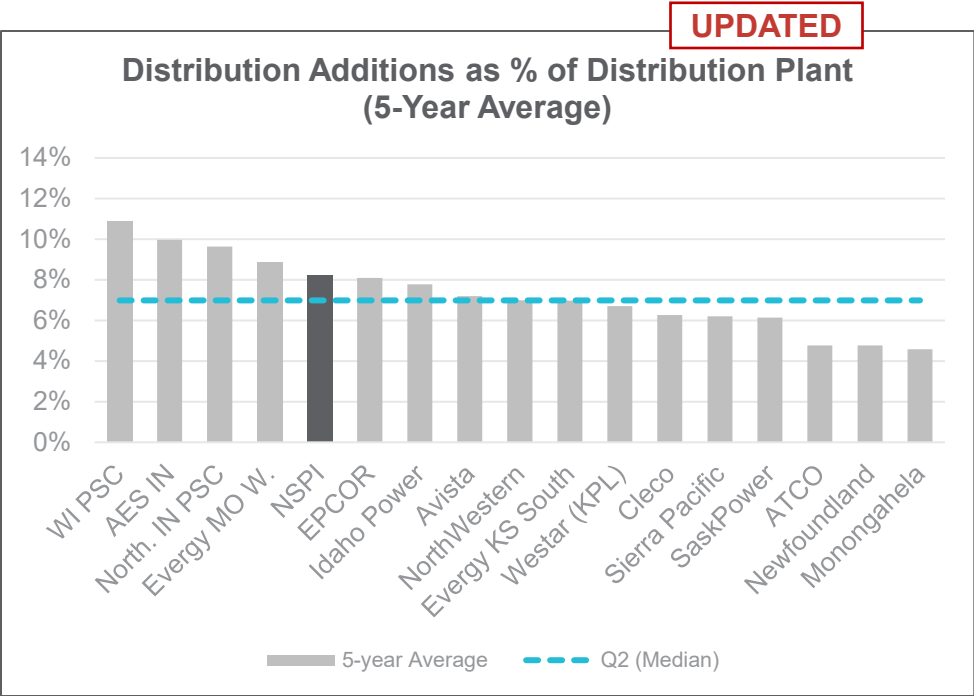
- On a 5-year average basis, NSPI Transmission Additions as a Percent of Depreciation Expense is below the peer group median and is third lowest
- NSPI Transmission Additions as a Percent of Depreciation Expense decreased 52 percentage points between 2019 and 2023, after a spike in 2021. The peer median Transmission Additions as a Percent of Depreciation Expense **increased 42** ~~decreased 36~~ percentage points over the same timeframe
- NSPI Transmission Additions in 2023 were 9% lower in nominal terms than in 2019 while the peer median Transmission Additions were **58% 29%** higher in 2023 than in 2019
- NSPI Transmission Depreciation Expense in 2023 was 20% higher in nominal terms than in 2019 while the peer median Transmission Depreciation Expense was **48% 62%** higher in 2023 than in 2019

UPDATED



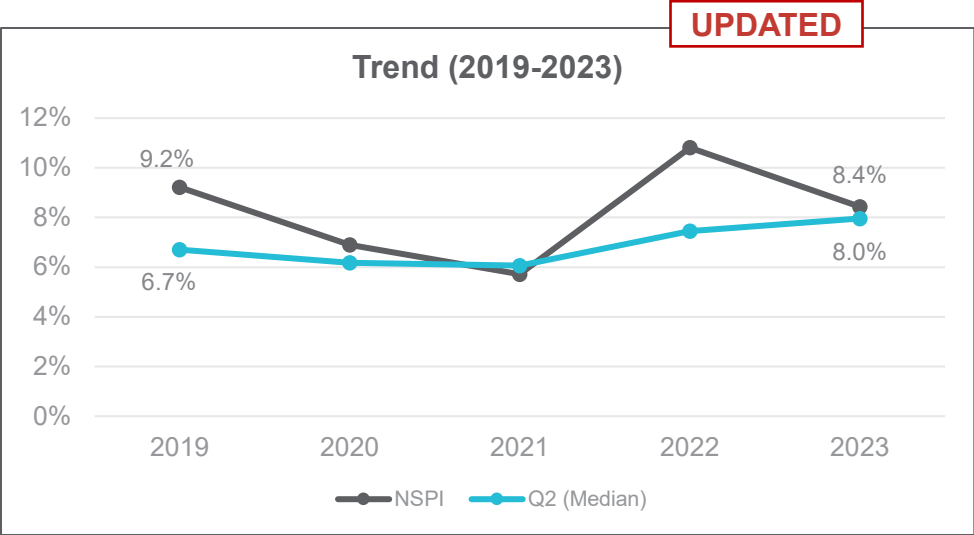
**Duke Energy Kentucky is excluded from transmission benchmarks as they are largely transmission dependent (i.e., the company relies on more wheeling than transmitting on their own transmission system).*

CA8 – Distribution Additions as % of Distribution Plant



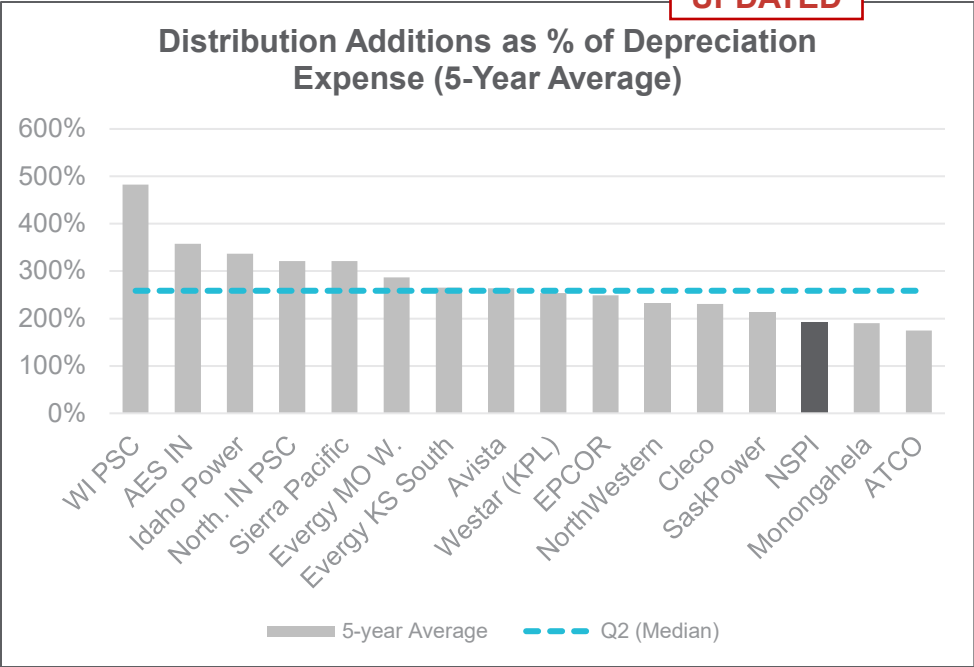
Observations

- On a 5-year average basis, NSPI Distribution Additions as a Percent of Distribution Plant is above the peer group median
- NSPI Distribution Additions as a Percent of Distribution Plant decreased almost 1 percentage point between 2019 and 2023. The peer median Distribution Additions as a Percent of Distribution Plant **increased 1.3 percentage points** ~~was flat~~ over the same timeframe
- NSPI Distribution Additions in 2023 were 14% higher in nominal terms than in 2019 while the peer median Distribution Additions were **45% 4%** higher in nominal terms in 2023 than in 2019
- NSPI Distribution Plant in 2023 was 23% higher in nominal terms than in 2019 while the peer median Distribution Plant was **36% 31%** higher in 2023 than in 2019



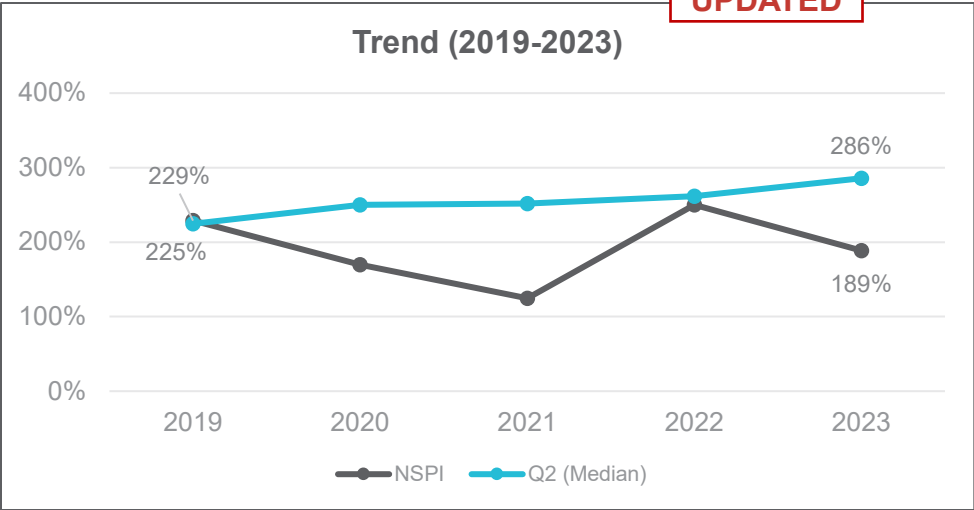
CA9 – Distribution Additions as % of Depreciation Expense

UPDATED

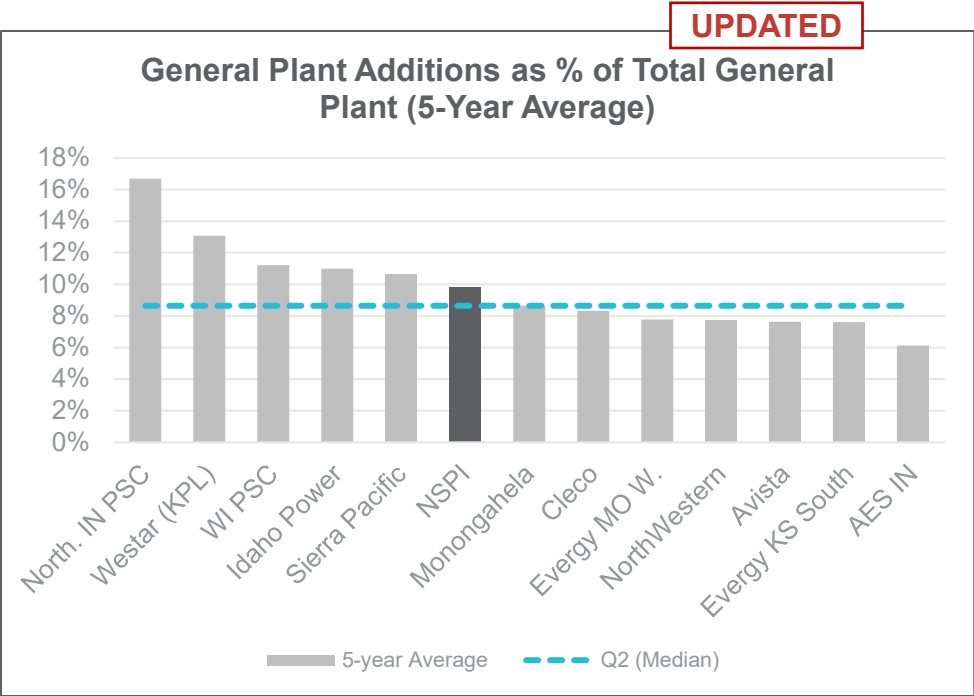


- Observations**
- On a 5-year average basis, NSPI Distribution Additions as a Percent of Depreciation Expense is below the peer group median
 - NSPI Distribution Additions as a Percent of Depreciation Expense decreased by more than 100 percentage points from 2019 to 2021, increased 125 percentage points in 2022, and then ended in 2023 at a level 40 percentage points lower than in 2019. The peer median Distribution Additions as a Percent of Depreciation Expense increased 61 7 percentage points over the same timeframe
 - NSPI Distribution Additions in 2023 were 14% higher in nominal terms from than in 2019 while the peer median Distribution Additions were 45% 4% higher in nominal terms in 2023 than in 2019
 - NSPI Distribution Depreciation Expense in 2023 was 38% higher in nominal terms than in 2019 while the peer median Distribution Depreciation Expense was 29% 51% higher in 2023 than in 2019

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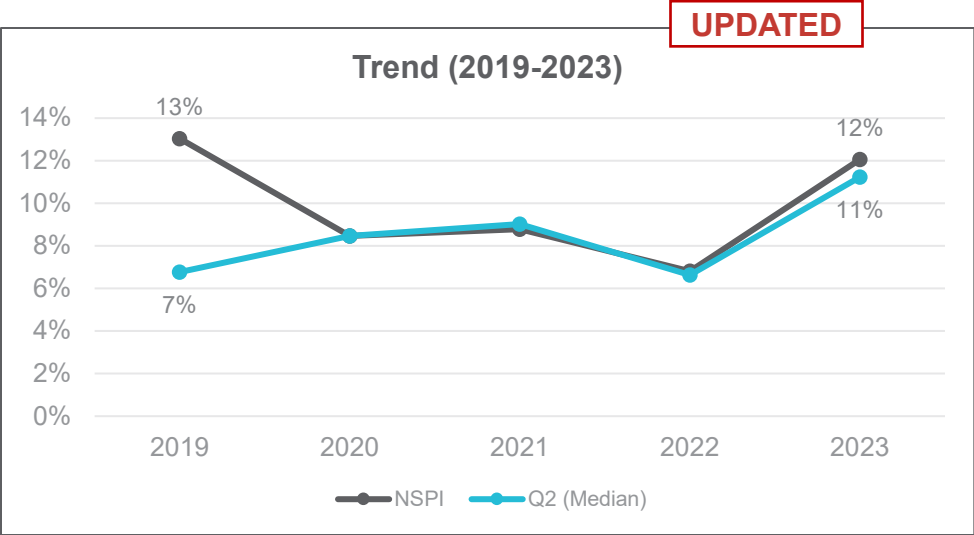


CA10 – General Plant Additions as % of Total General Plant



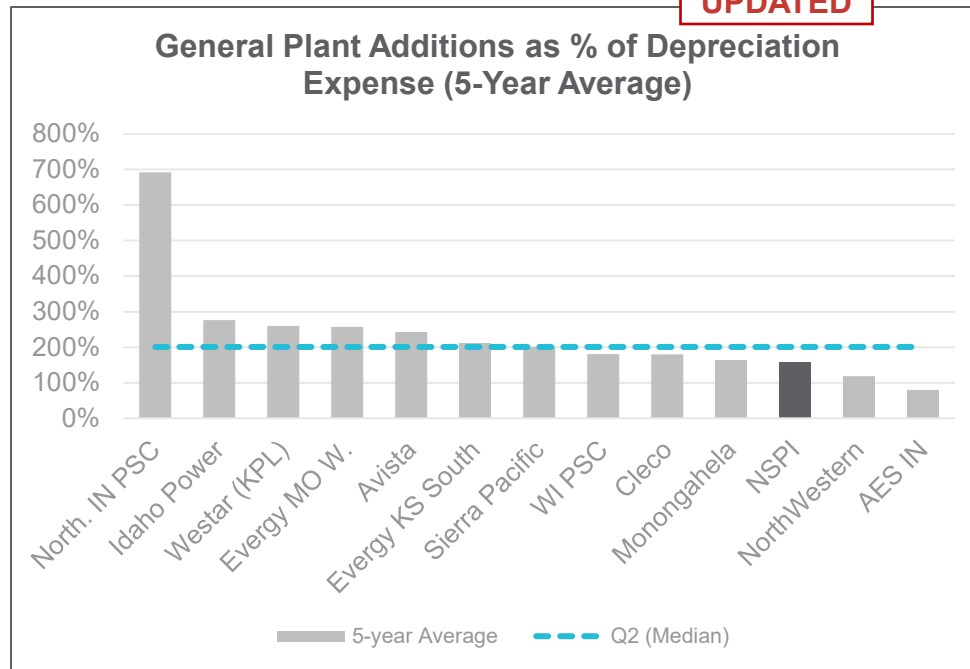
Observations

- On a 5-year average basis, NSPI General Plant Additions as a Percent of Total General Plant is **above at** the median of the peer group
- NSPI General Plant Additions as a Percent of Total Plant decreased 1 percentage point between 2019 and 2023, after being much lower in 2020-2022. The peer median General Plant Additions as a Percent of Total Plant **increased 4 percentage points stayed flat** over the same timeframe
- NSPI General Plant Additions in 2023 were 19% higher in nominal terms than in 2019 while the peer median General Plant Additions were **9% 34%** higher in 2023 than in 2019
- NSPI General Plant in 2023 was 28% higher in nominal terms from than in 2019 while the peer median General Plant was **25% 22%** higher in 2023 than in 2019



CA11 – General Plant Additions as % of Depreciation Expense

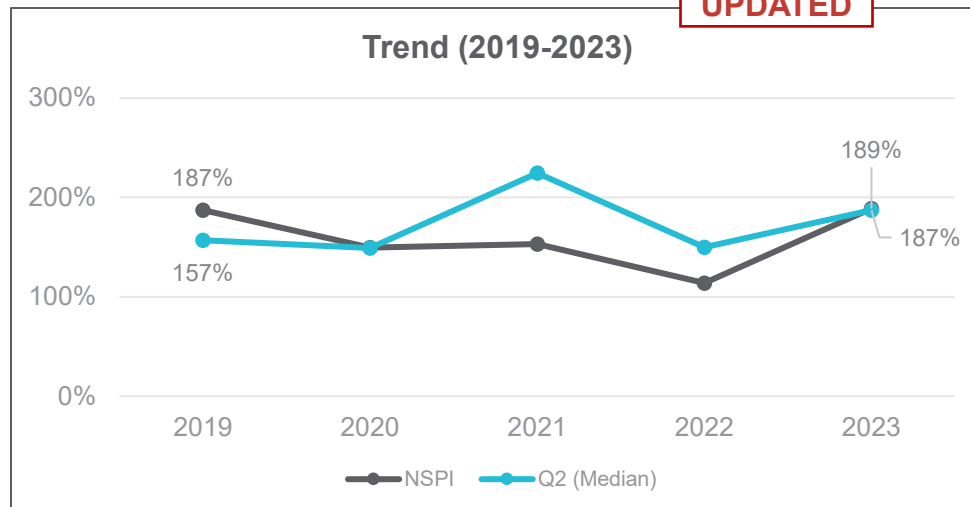
UPDATED



Observations

- On a 5-year average basis, NSPI General Plant Additions as a Percent of Depreciation Expense is below the peer group median and **second third** lowest
- NSPI General Plant Additions as a Percent of Depreciation Expense increased 2 percentage point between 2019 and 2023, decreasing significantly from 2020 to 2022 before increasing back near 2019 levels. The peer median General Plant Additions as a Percent of Depreciation Expense increased **30 2** percentage points over the same timeframe
- NSPI General Plant Additions in 2023 were 19% higher in nominal terms than in 2019 while the peer median General Plant Additions **increased** were **9% 34%** higher in 2023 than in 2019
- NSPI General Plant Depreciation Expense in 2023 was 18% higher in nominal terms than in 2019 while the peer median General Plant Depreciation Expense was **28% 39%** higher in 2023 than in 2019

UPDATED



Summary Observations

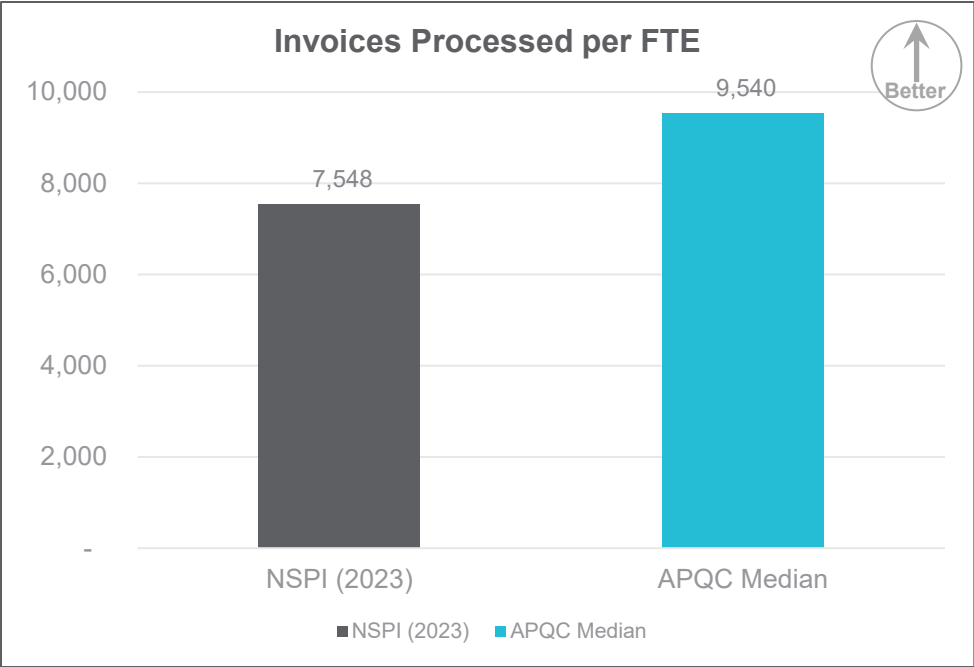
- On a 5-year average basis, NSPI Capital Employed per Retail Customer is **just** below the median. ~~On a trend basis, NSPI moved above the median in 2021-2023~~
- On a 5-year average basis, NSPI Total Plant Additions as a Percent of Total Electric Plant is lower than the peer group median, driven by its relatively lower Total Plant Additions **as a Percent of Total Electric Plant** in 2020, ~~and 2021~~, **and 2023**. NSPI Total Plant Additions as a Percent of Total Electric Plant is in line with the peer group median for ~~2019, 2022, and 2023~~
- NSPI Total Plant Additions as Percent of Depreciation Expense is below the peer group median each year and the second lowest among peers on a 5-year average basis
- NSPI Production Additions as a Percent of Production Plant and as a Percent of Depreciation Expense are both just **above below** the median on a 5-year average basis. In each case, the NSPI was above the median in the **last three years final year** analyzed
- NSPI Transmission Additions as a Percent of Transmission Plant and as a Percent of Depreciation Expense were below the peer group median on a 5-year average basis, and below the median in four of the five years analyzed
- NSPI Distribution Additions as a Percent of Distribution Plant is above the peer group median on a 5-year average basis and in four of the five years analyzed
- NSPI Distribution Additions as a Percent of Depreciation Expense was **consistently** at or below the peer group median in each of the past five years and below the median on a 5-year average basis
- On a 5-year average basis, NSPI General Plant Additions as a Percent of General Plant is **above in-line-with** the peer group median. NSPI General Plant Additions as a Percent of General Plant was notably higher than the peer group median in 2019 **and 2023**
- NSPI General Plant Additions as a Percent of Depreciation Expense is below the median on a 5-year average basis, in line with the peer group median in **2020 2019** and 2023, and lower than the peer group median in **2021 and 2022 2020-2022**



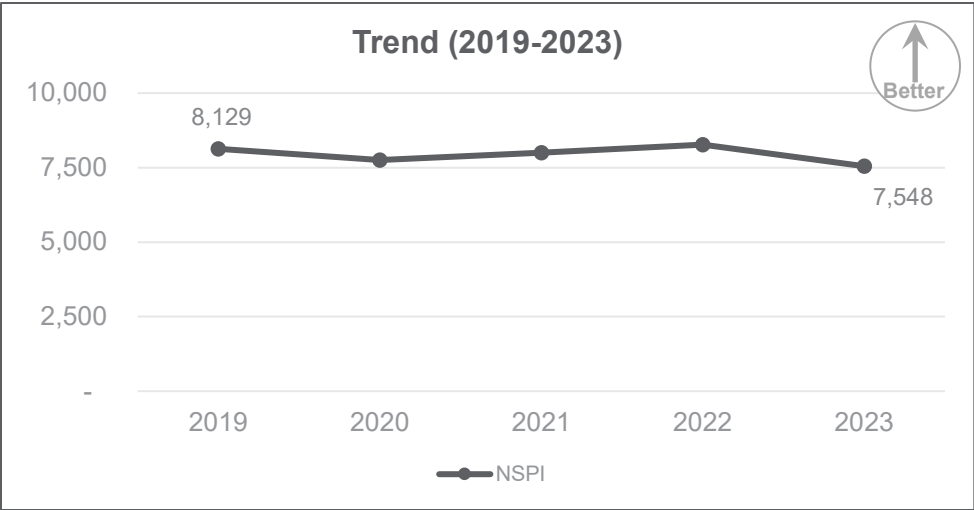
Finance & Accounting Metrics



FA1 – Invoices Processed per Full Time Employee (FTE)



- Observations**
- NSPI Invoices Processed per Full Time Equivalent (FTE) is 21% below the industry group median
 - NSPI Invoices Processed per Full Time Equivalent decreased 7% between 2019 and 2023 (-1.8% CAGR)
 - NSPI Invoices Processed increased 2% over the period 2019 to 2023 (0.5% CAGR) while the number of FTEs that perform the process "process accounts payable" increased by 1, or 10%, over the same timeframe

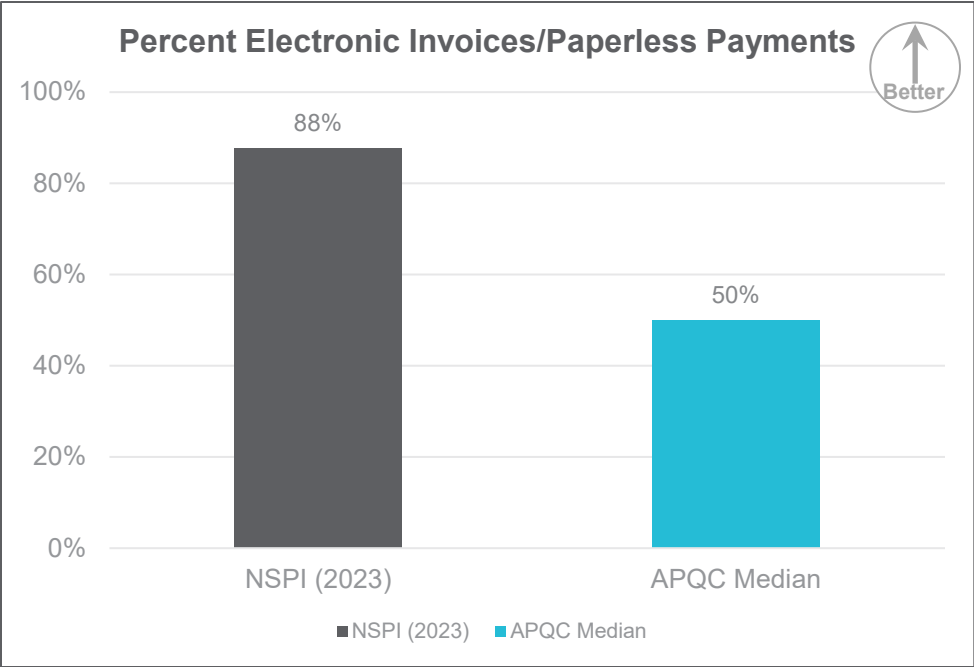


Definition: Total annual number of invoices processed / Number of FTEs that perform the processes "process accounts payable"

"Process accounts payable" consists of processing payments for operating expenses and other supplier charges, which includes verifying of accounts payable with vendor records, maintaining and managing electronic commerce, auditing invoices and approving payments, processing financial accruals and reversals, processing payments and taxes, researching and resolving exceptions, and adjusting accounting records. It also encompasses the development of policies and procedures around the processing of accounts payable and all related operations.

Source: APQC – Accounts Payable Key Benchmarks – Utility 2024

FA2 – Percent Electronic Invoices / Paperless Payments

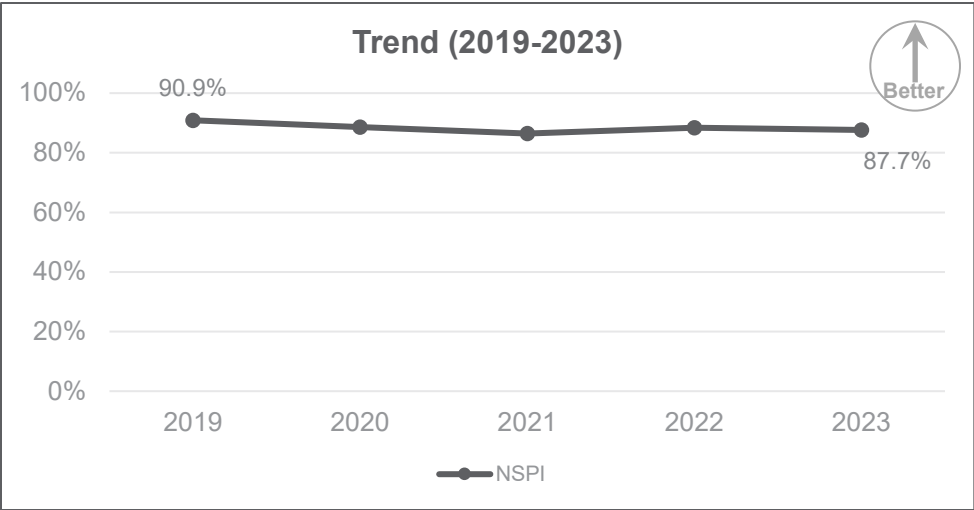


Observations

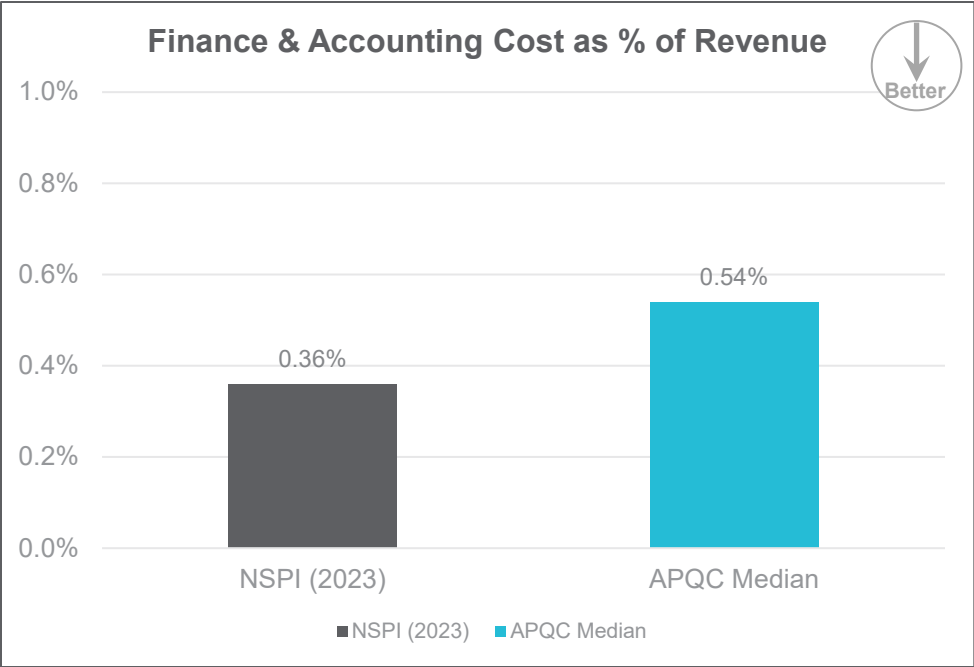
- NSPI Percent Electronic Invoices/Paperless Payments in 2023 is 38 percentage points higher than the industry group median
- NSPI Percent Electronic Invoices/Paperless Payments decreased 3 percentage points between 2019 and 2023 (-0.9% CAGR)
- NSPI Invoice Line Items Processed Electronically decreased 18% over the period 2019 to 2023 (-5.0% CAGR) while the Annual Invoice Line Items decreased 15% over the same timeframe (-4.1% CAGR)

Definition: Percentage of invoice line items invoiced using electronic or automatic methods. This means there were no printed paper documents.

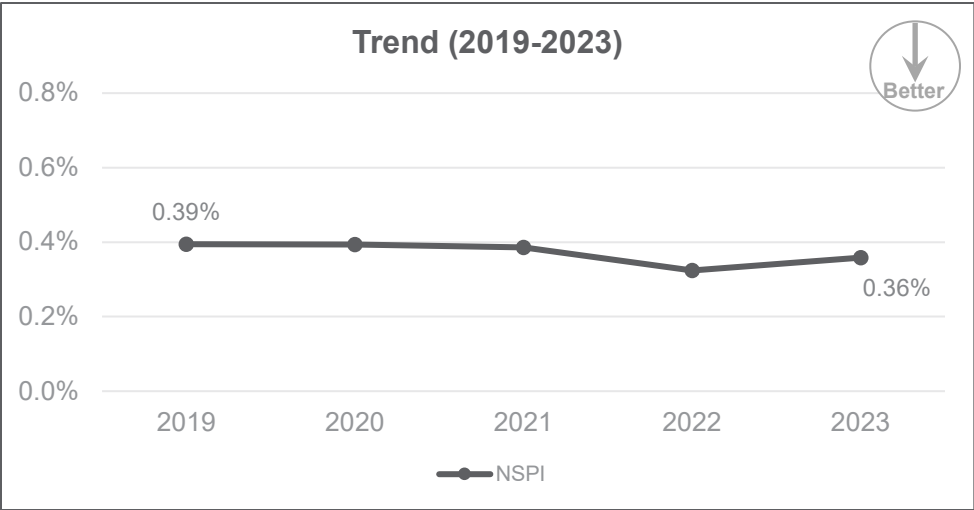
Source: APQC – Key Customer and Credit Benchmarks - Utility 2024



FA3 – Finance & Accounting Cost as % of Revenue



- Observations**
- NSPI Finance & Accounting Cost as Percent of Revenue in 2024 is 0.18 percentage points below (or better than) the industry group median
 - NSPI Finance & Accounting Cost as Percent of Revenue decreased 0.03 percentage points over the period 2019 to 2023
 - NSPI Finance & Accounting Cost increased 6% in nominal terms from 2019 to 2023 (1.5% CAGR) while Regulated Revenue increased 17% over the same timeframe (4.0% CAGR)

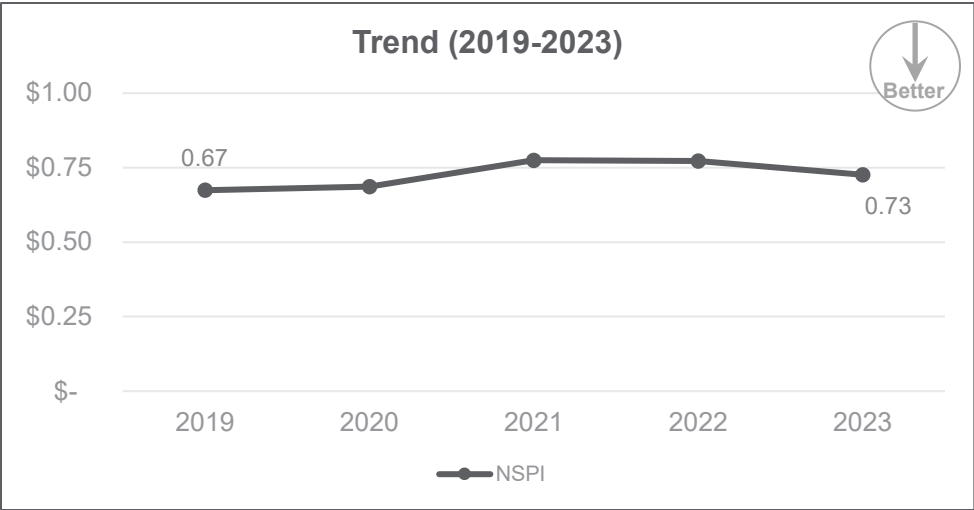
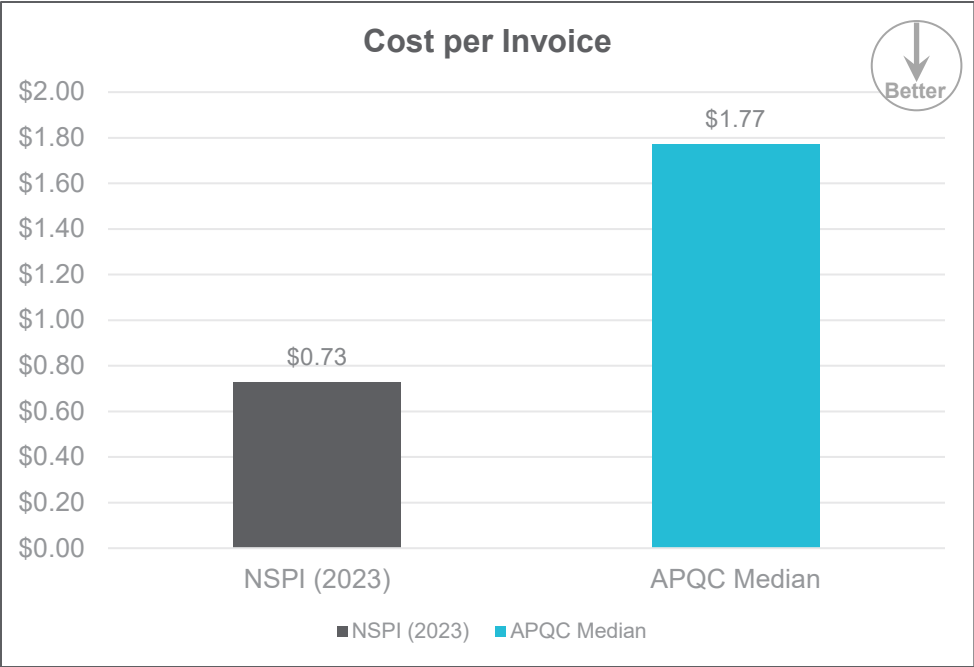


Definition: Total annual finance function cost, including all personnel, systems, overhead and other costs for both internal resources (within your enterprise or parent organization) and external resources (such as third-party organizations) / Total Revenue

The following are the main finance function process areas: financial strategy and planning, investment management, tax funding and treasury, profitability and cost management, revenue cycle, accounts payable and expense reimbursements, payroll, general accounting and reporting, fixed asset management, and internal audit. Include all of the different processes within the revenue, payroll, and accounts payable and expense reimbursement cycles even if they do not traditionally sit within finance.

Source: APQC – Finance Organization Benchmarks - Utility 2024

FA4 – Cost per Invoice



Observations

- NSPI Cost per invoice in 2023 is significantly lower (or better) than the industry group median
- NSPI Cost per Invoice increased 8% over the period 2019 to 2023 (1.9% CAGR)
- NSPI's costs to generate and deliver invoices increased 13% on a nominal basis between 2019 and 2023 (3.0% CAGR) while the Number of Invoices increased 4% over the same timeframe (1.1% CAGR)

Definition: *Total annual cost to generate and deliver invoices*

The focus here is the process of generating and delivering customer invoices. It includes creating methods and procedures for communicating and delivering invoices and statements for services and products. The process encompasses the maintenance of customer/product master files, the generation and transmittal of customer billing data to the customer, the posting of receivable entries, and the resolution of customer billing inquiries. It does not include receiving payments.

Source: APQC – Customer Credit Benchmarks - Utility 2024

Summary Observations

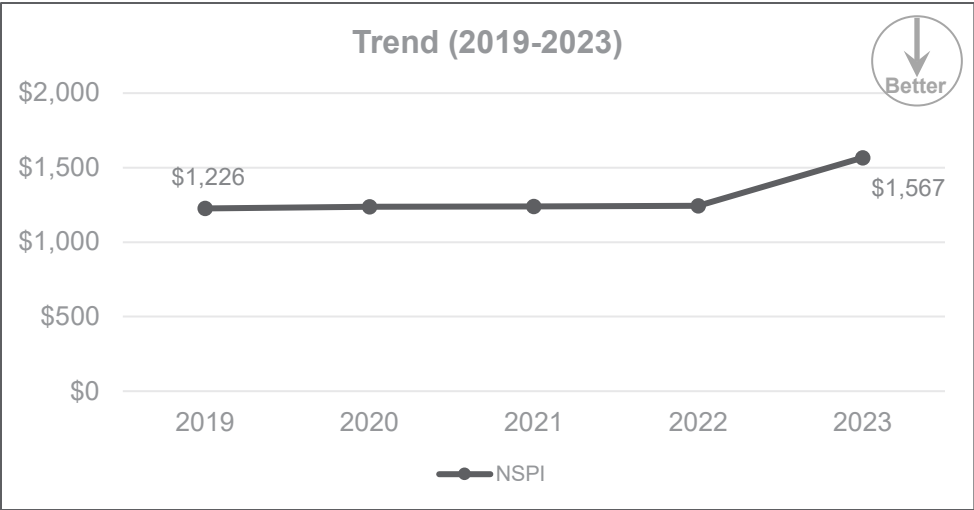
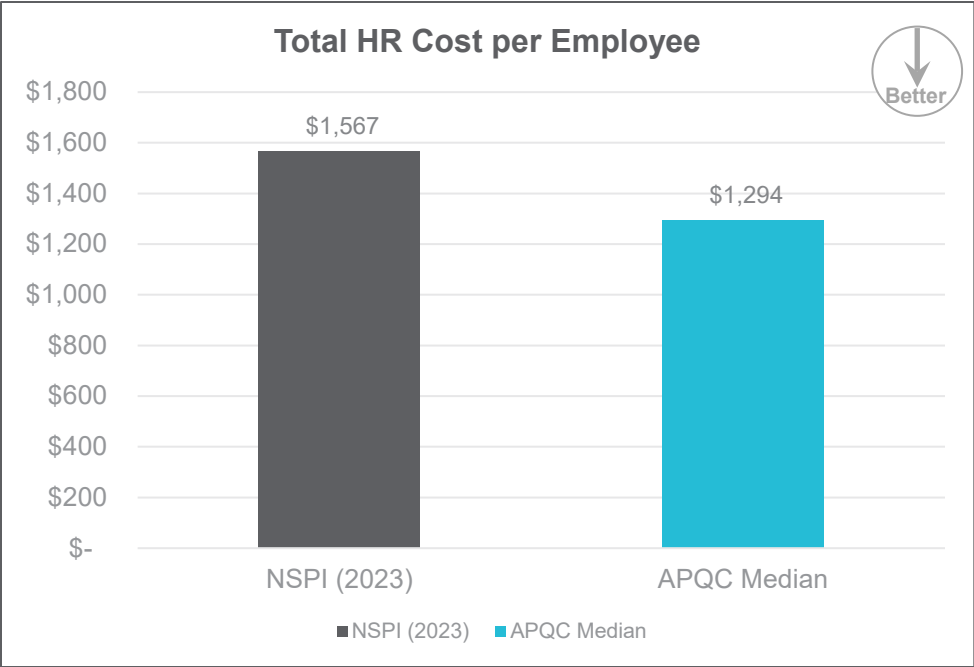
- NSPI's Finance & Accounting function performed very well on three of the four metrics analyzed compared to the peer median benchmarks, the exception being Invoices Processed per Full Time Employee (FTE) which is below the industry group median



Human Resources Metrics



HR1 – Total HR Cost per Employee



Observations

- NSPI Total HR Cost per FTE in 2023 is 21% higher than the industry group median
- NSPI Total HR Cost per FTE increased 21% over the period 2019 to 2023 (6.3% CAGR), with most of the increase occurring in 2023
- NSPI Total HR Cost increased 41% in nominal terms between 2019 and 2023 (9.0% CAGR) while the number of Business Entity Employees increased by 11% over the same timeframe (2.5% CAGR)

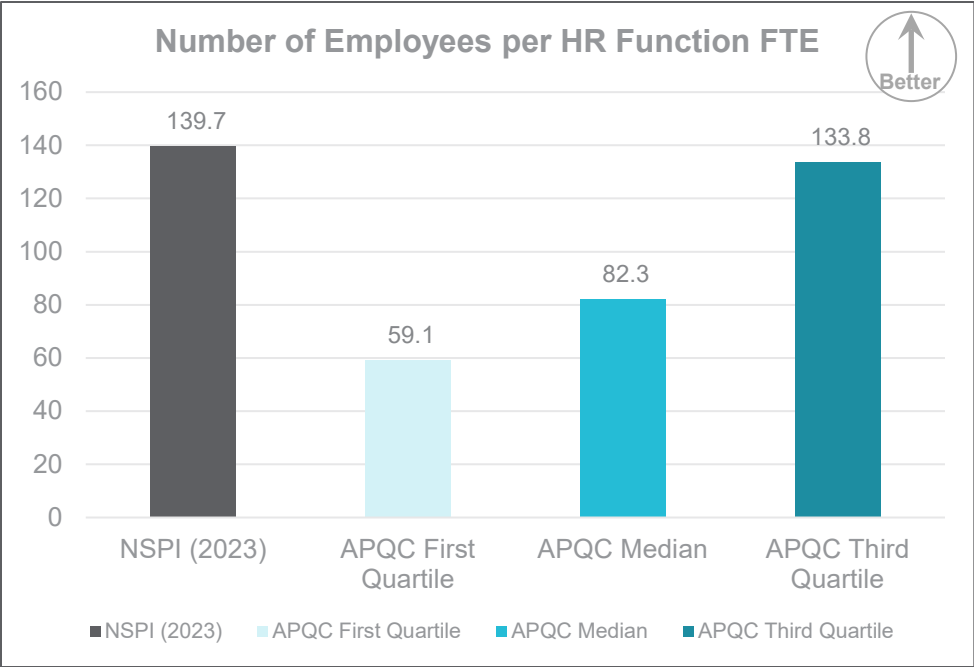
Factors Contributing to Performance

- NSPI has seen increased HR costs due to the need to attract, retain and train specialized employees. There is a general shortage of skilled trade employees in Canada resulting in the need for increased investment to recruit these limited employees and build training programs to develop them internally

Definition: Total cost to perform the function "develop and manage human capital" / Number of business entity employees.

Source: APQC – HR Function Key Benchmarks - Utility 2024

HR2 – Number of Employees per HR Function FTE

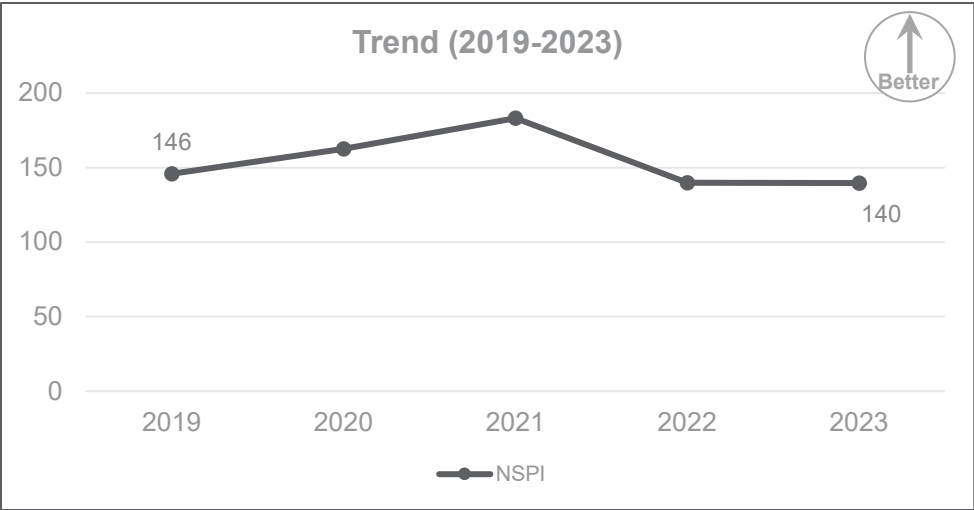


Observations

- NSPI Number of Business Entity Employees per HR Function FTE in 2023 is more than two-thirds higher than the industry group median
- NSPI Number of Business Entity Employees per HR Function FTE decreased 4% from 2019 to 2023 (-1.1% CAGR)
- NSPI number of Business Entity Employees increased 11% in nominal terms from 2019 to 2023 (3.4% CAGR) while number of HR Function FTEs increased by 15% over the same timeframe (4.9% CAGR)

Factors Contributing to Performance

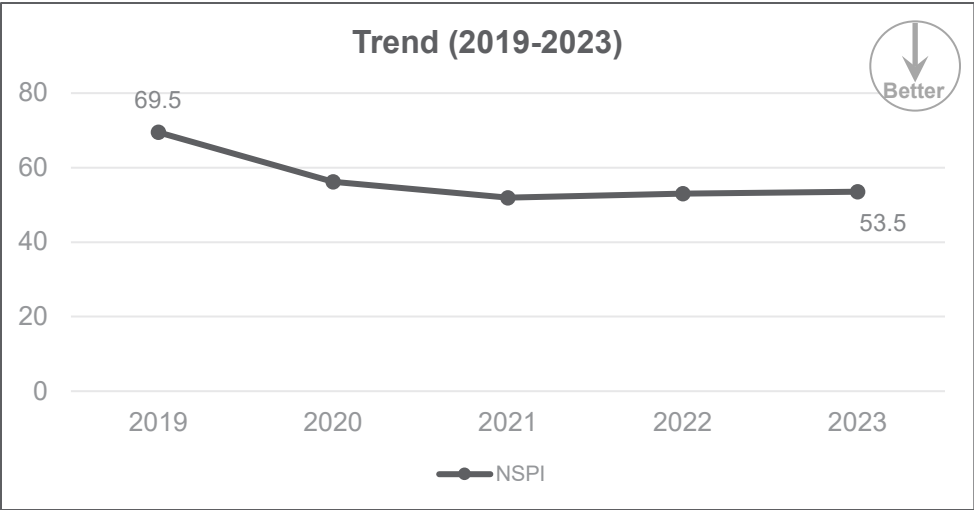
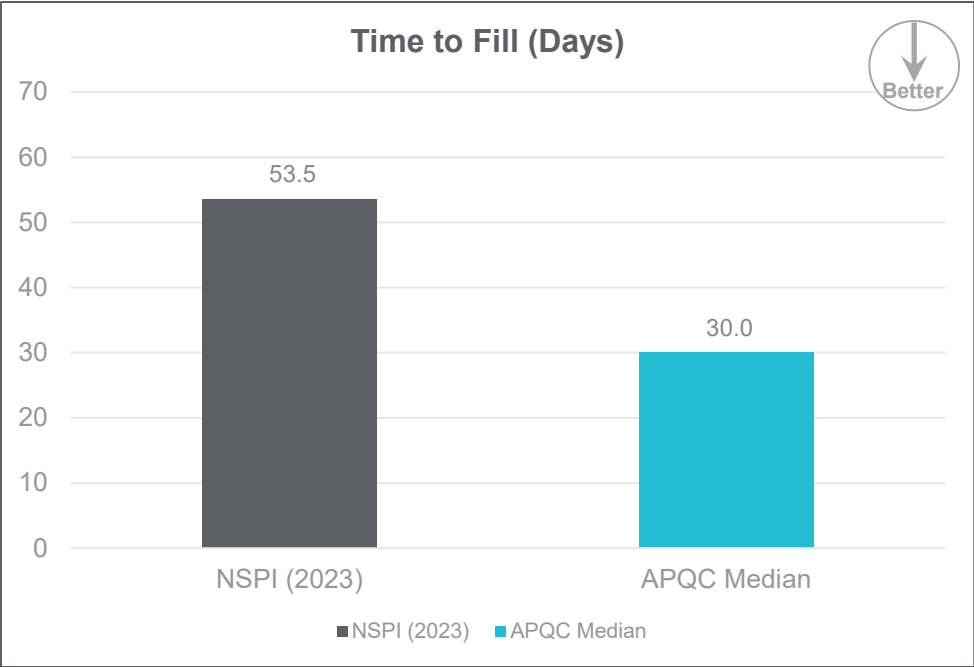
- NSPI’s higher number of employees per HR Function FTE is partially as a result of the shared service structure in which NSPI is provided HR services from Emera



Definition: Number of business entity employees / Number of FTEs who perform the function "develop and manage human capital".

Source: APQC – HR Function Key Benchmarks - Utility 2024

HR3 – Time to Fill (Days)



Observations

- NSPI Time to Fill in 2023 is 78% higher than the industry group median
- NSPI Time to Fill decreased 23% between 2019 and 2023 (-6.3% CAGR)

Definition: Cycle time in calendar days from approval of job requisition to acceptance of job offer.

Source: APQC – Talent Acquisition Benchmarks - Utility 2024

Summary Observations

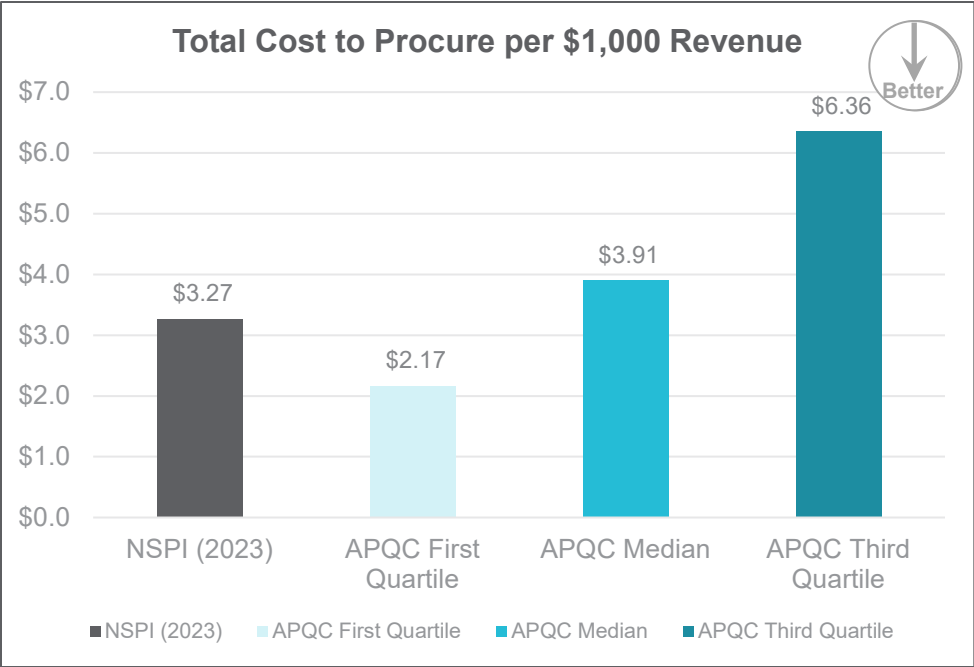
- NSPI has seen increased HR costs due to the need to attract, retain and train specialized employees. There is a general shortage of skilled trade employees in Canada resulting in the need for increased investment to recruit these limited employees and build training programs to develop them internally.
- NSPI's Number of Employees per HR FTE compares favorably against the industry group median
- NSPI has a longer Time to Fill positions compared to the industry group median, but with an improving trend



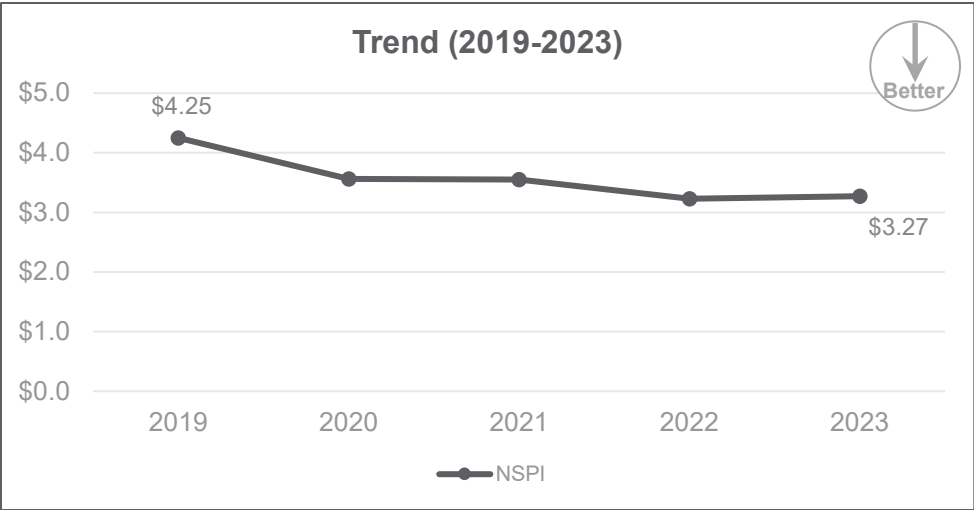
Supply Chain Metrics



SC1 – Total Cost to Procure per \$1,000 Revenue



- Observations**
- NSPI Total Cost to Perform the Process Group "Procure Materials and Services" per \$1,000 Revenue in 2023 is 16% lower than the industry group median
 - NSPI Total Cost to Perform the Process Group "Procure Materials and Services" per \$1,000 Revenue decreased by 23% from 2019 and 2023 (-6.3% CAGR)
 - Total Cost to Procure decreased 10% nominally over the past five years (-2.6% CAGR) while Revenue increased 17% over the same timeframe (4.0% CAGR)

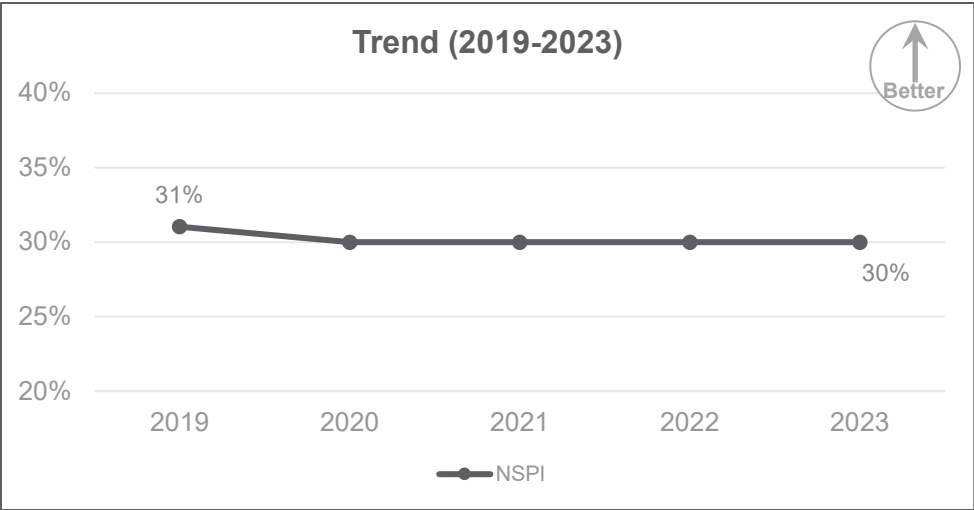
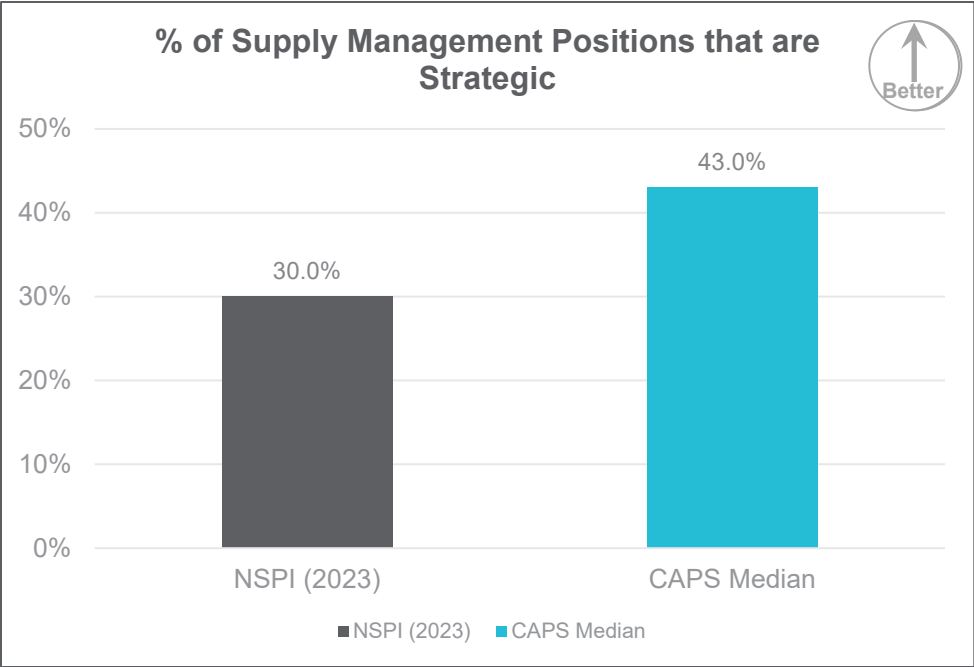


Definition: *Total cost to perform the process group "procure materials and services" / (Total business entity revenue * 0.001)*

Total process cost is the sum of outsourced, overhead, personnel, system, and other costs. The value of all goods and services purchased by your site annually should include all capital expenditure items. The process group "procure materials and services" describes the work of procurement planning, purchasing, and sourcing beginning with developing sourcing strategies for materials and services, the selection of suppliers to provide the materials and services, the development and maintenance of the corresponding contracts, and the ordering of materials and services.

Source: APQC – Benchmarks on Demand - Utility Industry 2024

SC2 – % of Supply Management Positions that are Strategic



Observations

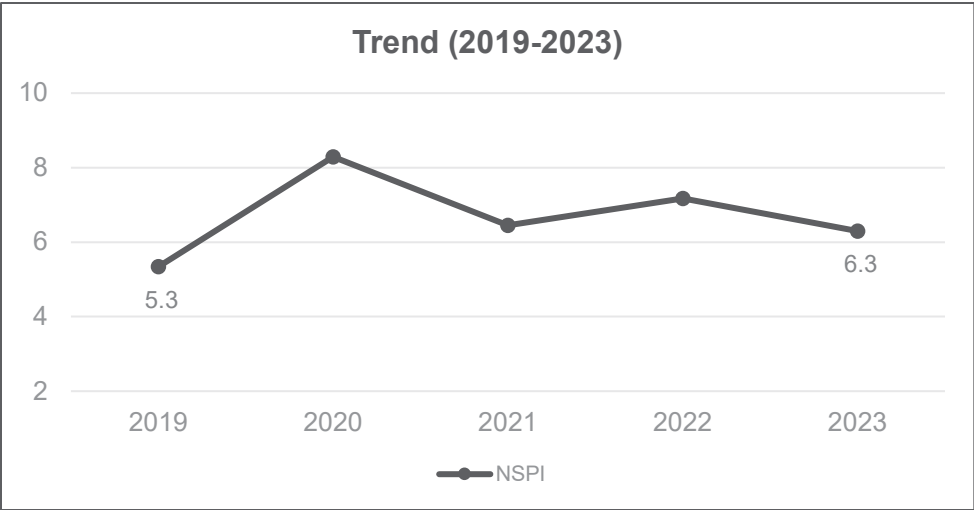
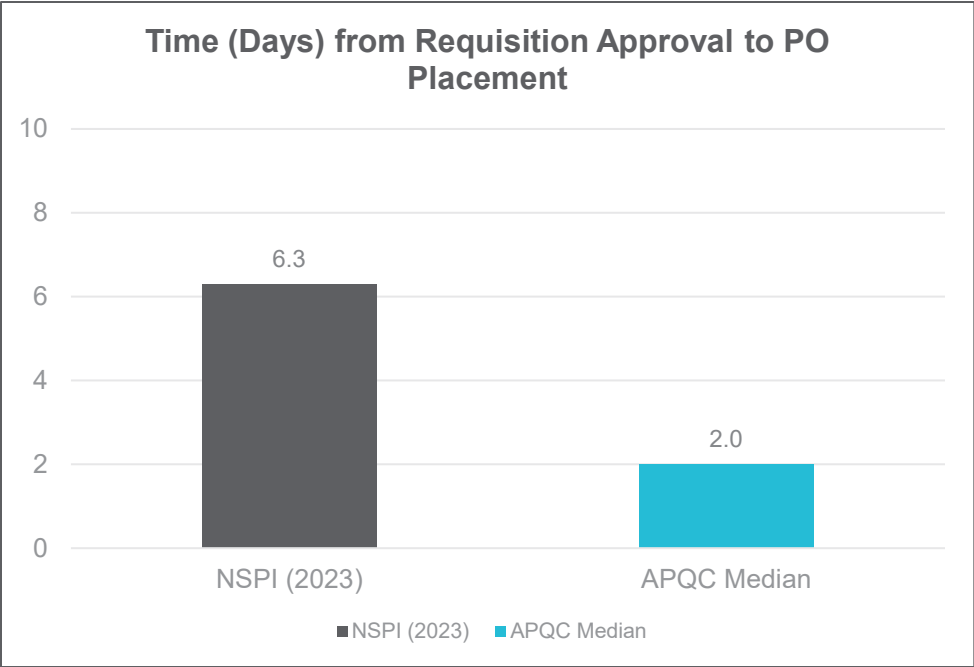
- NSPI Percent of Supply Management Positions that are Strategic in 2023 is 13 percentage points lower than the industry group median
- NSPI Percent of Supply Management Positions that are Strategic decreased 1 percentage point between 2019 and 2023
- NSPI number of FTEs that are Strategic remained flat between 2019 and 2023 while the total number of FTEs in sourcing and purchasing increased 3% over the same timeframe (0.9% CAGR)

Definition: Strategic employees are engaged in long-range sourcing and procurement activities that are critical to the organization’s ability to meet its core business objectives.

Supply management employees include sourcing and purchasing staff and the supervisors/managers that provide daily oversight of those activities. Do not include staff in logistics or materials management.

Source: CAPS Research – Cross Industry Benchmarks – Utility 2023

SC3 – Cycle Time to Issue a Purchase Order for Goods



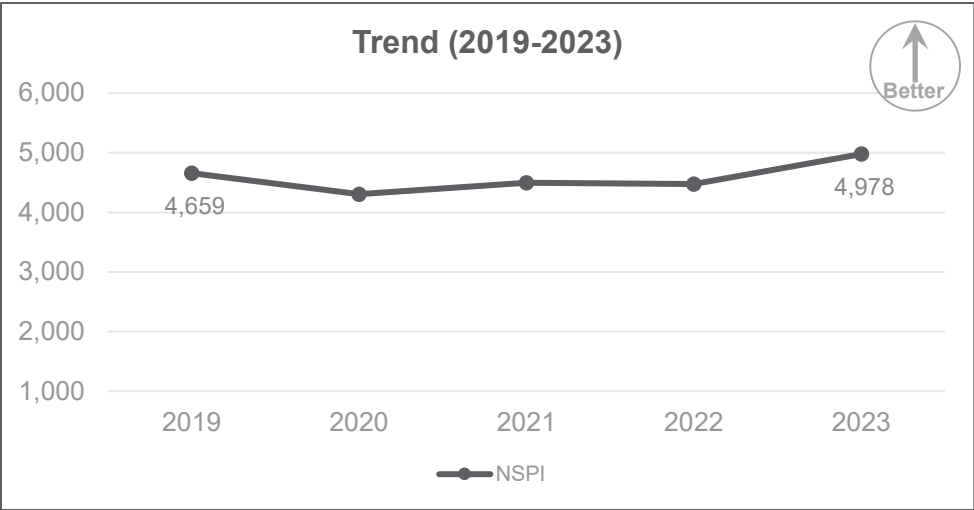
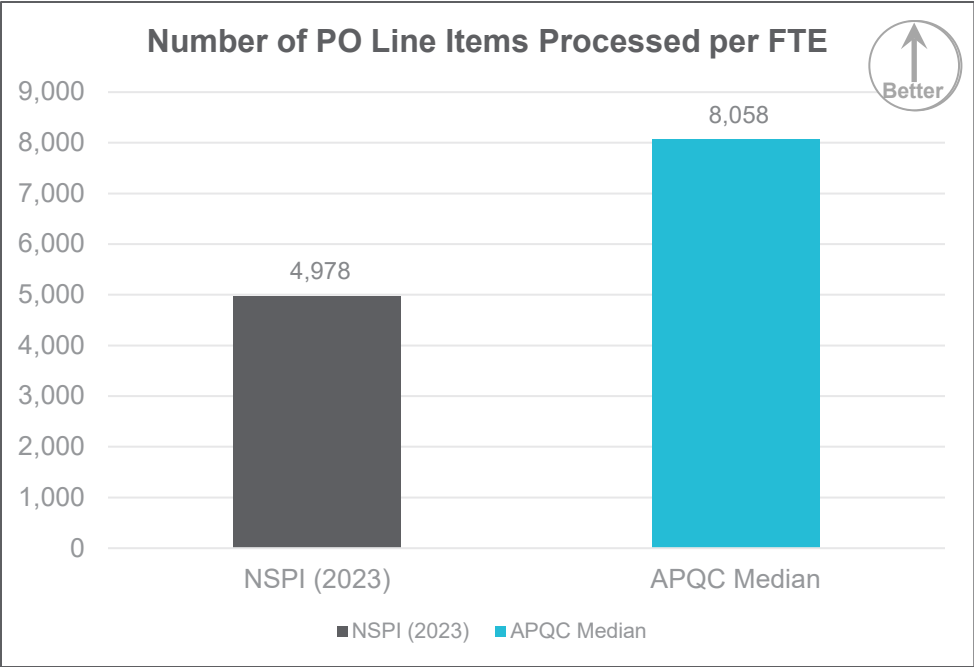
Observations

- NSPI Average Days from Receipt of Purchase Requisition to PO Placement in 2023 is above the industry group median
- NSPI Average Days from Receipt of Purchase Requisition to PO Placement increased 18% between 2019 and 2023

Definition: Cycle time to issue a purchase order for goods in days (including weekends)

Source: APQC – Procurement Benchmarks - Utility 2024

SC4 – Number of PO Line Items Processed per FTE



Observations

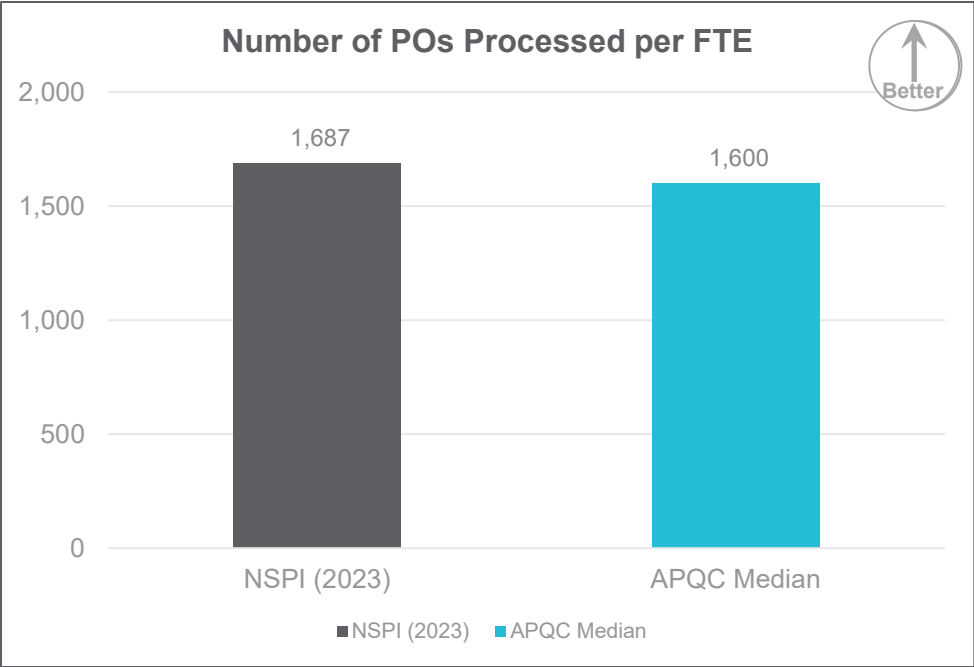
- NSPI Number of PO Line Items Processed per FTE in 2023 is 38% lower than the industry group median
- NSPI Number of PO Line Items Processed per FTE increased 7% between 2019 and 2023
- NSPI number of PO Line Items Processed increased 7% between 2019 and 2023 (1.7% CAGR) while the number of FTEs who process orders for materials and services remained flat over the same timeframe

Definition: Total annual number of purchase order line items processed

Number of FTEs who process orders for materials and services". Ordering materials and services includes creating and approving requisitions and distributing purchase orders accordingly, and hastening the procurement

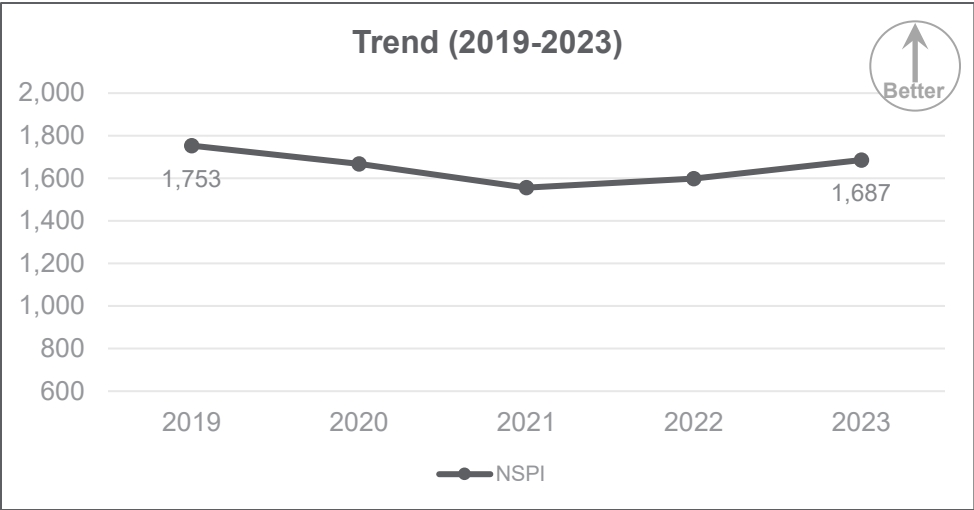
Source: APQC – Procurement Benchmarks - Utility 2024

SC5 – Number of POs Processed per FTEs



Observations

- NSPI Number of POs Processed per FTE in 2023 is 5% higher than the industry group median
- NSPI Number of POs Processed per FTE decreased 4% between 2019 and 2023
- NSPI number of POs Processed decreased 4% between 2019 and 2023 (-1.0% CAGR) while the number of FTEs who process orders for materials and services remained flat over the same timeframe



Definition: Total annual number of purchase orders processed

Number of FTEs who process orders for materials and services". Ordering materials and services includes creating and approving requisitions and distributing purchase orders accordingly, and hastening the procurement

Source: APQC – Procurement Benchmarks - Utility 2024

Summary Observations

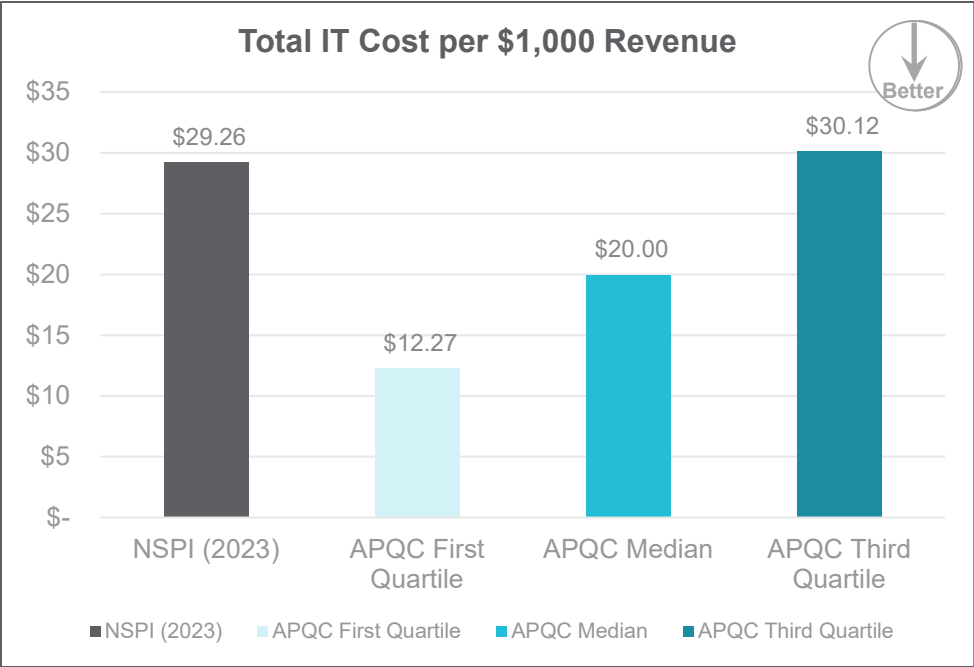
- NSPI Supply Chain Operating Expenses as a percent of revenue are lower than the industry group median benchmarks, and this ratio improved during the time period analyzed
- NSPI's Supply Chain function has a lower proportion of strategic positions than the industry group median
- NSPI takes longer to issue a PO from time of requisition than the industry group median
- NSPI processes fewer PO line items per FTE but more POs per FTE than the industry group median



Information Technology (IT) Metrics



IT1 – Total IT Cost per \$1,000 Revenue

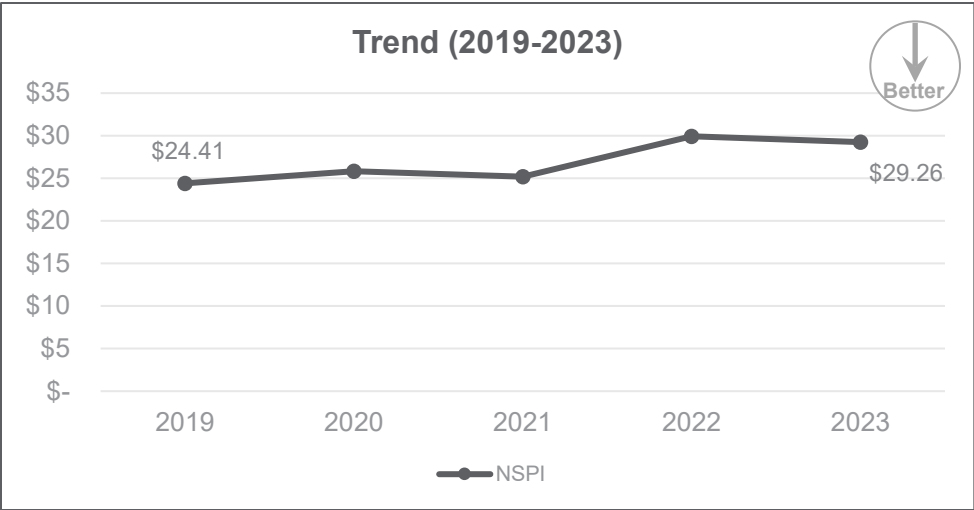


Observations

- NSPI Total IT Cost per \$1,000 Revenue in 2023 is 46% higher than the industry group median, and 3% lower than the third/fourth quartile line
- NSPI Total IT Cost per \$1,000 Revenue increased 20% between 2019 and 2023 (4.6% CAGR)
- NSPI Total IT Cost increased 40% nominally over the past five years (8.8% CAGR) while Revenue increased 17% over the same timeframe (4.0% CAGR)

Factors Contributing to Performance

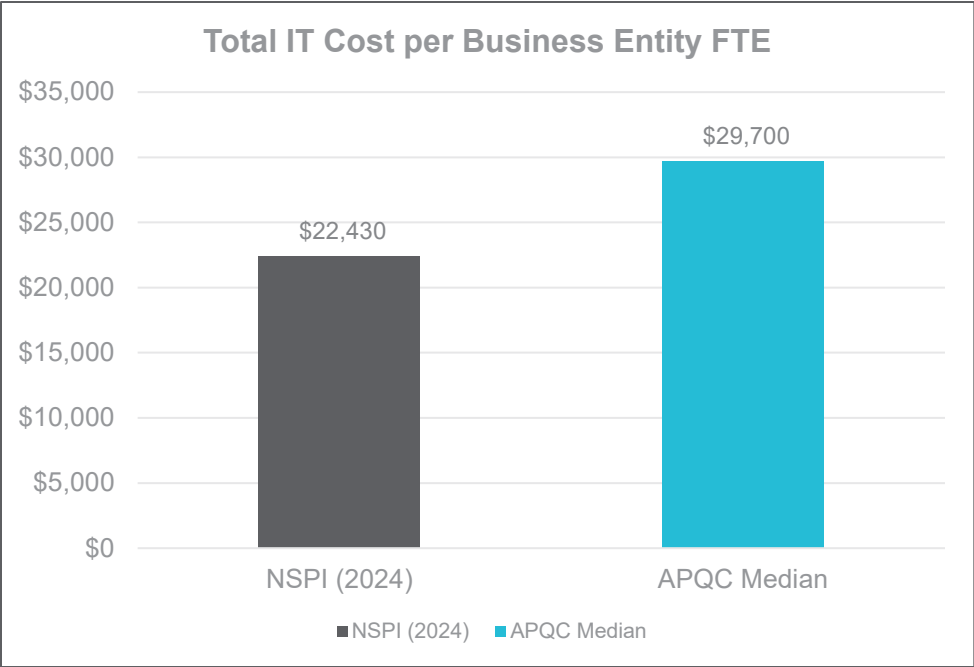
- NSPI is likely a smaller utility with less revenue than many of the utilities in the APQC benchmark and it is likely that other utilities have economies of scale that NSPI does not possess.



Definition: *Total annual IT cost (excluding depreciation/amortization) / (Total business entity revenue * 0.001)*

Source: APQC – Benchmarks on Demand - Utility Industry 2024

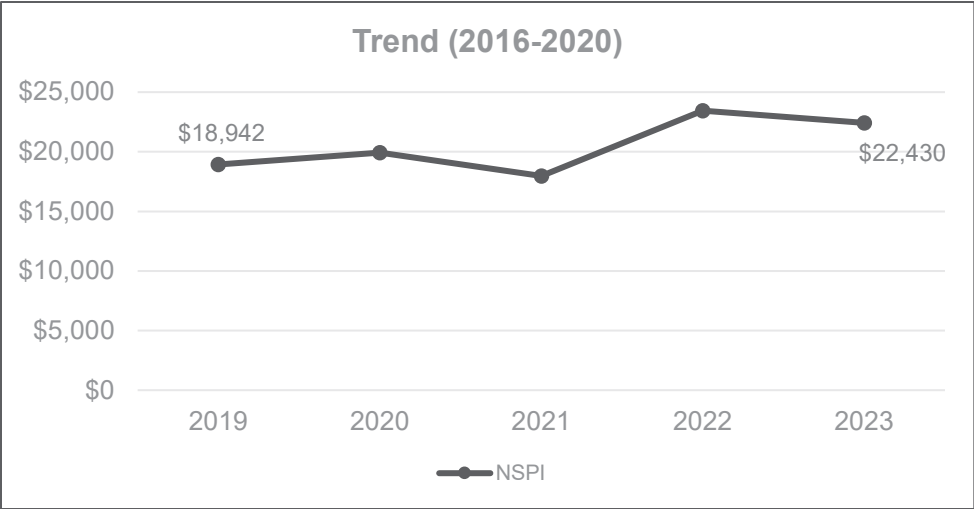
IT2 – Total IT Cost per Business Entity FTE



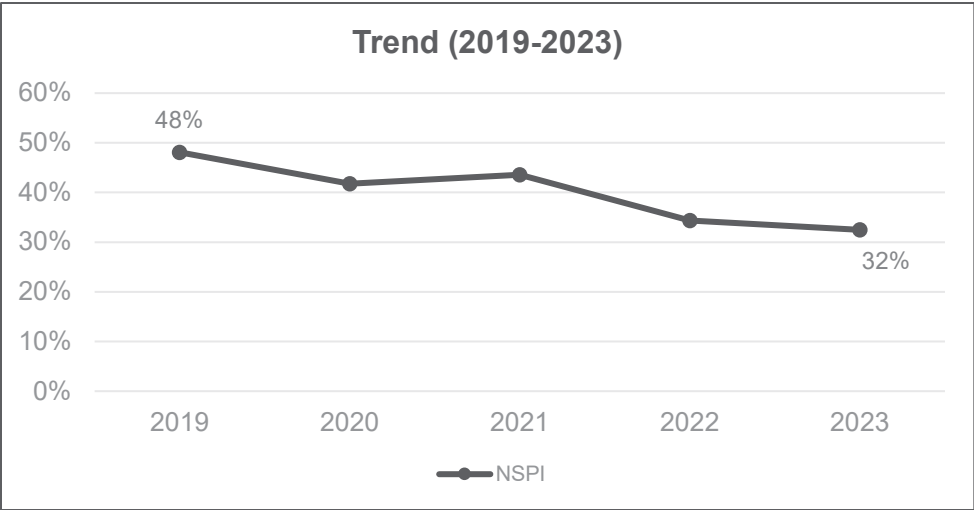
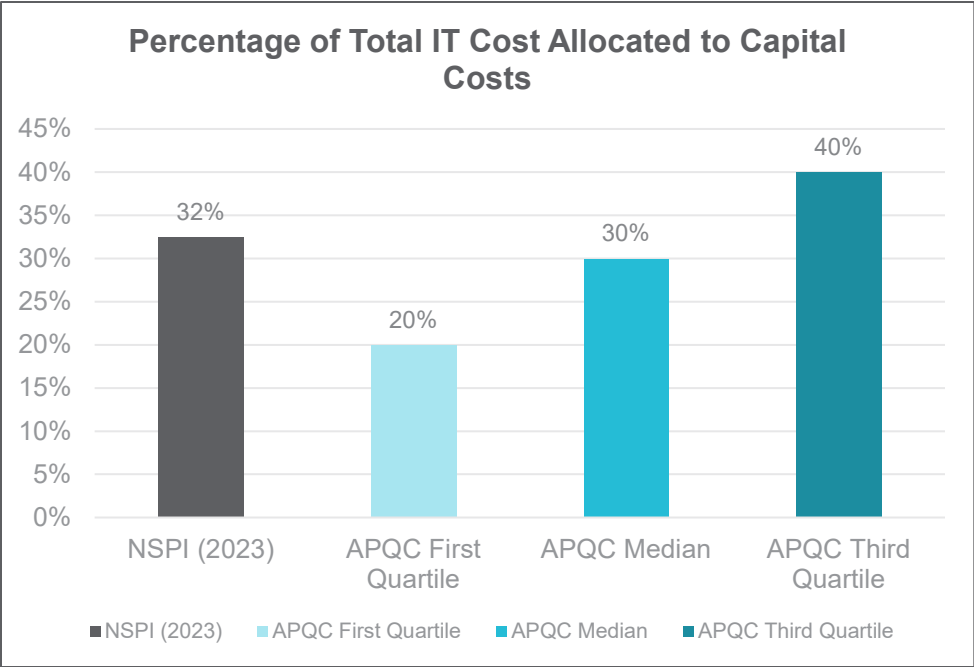
Observations

- NSPI Total IT Cost per Business Entity FTE in 2023 is 24% lower than the industry group median for 2024
- NSPI Total IT Cost per Business Entity FTE increased 18% between 2019 and 2023
- NSPI Total IT Cost increased 40% nominally over the past five years (8.8% CAGR) while number of Business Entity FTEs increased 18% over the same timeframe (4.3% CAGR)

Definition: *Total annual IT cost (excluding depreciation/amortization) / Number of business entity FTEs*



IT4 – Percentage of Total IT Cost Allocated to Capital Costs



Observations

- Percentage of Total IT Cost Allocated to Capital Costs in 2023 is just above the industry group median
- NSPI Percentage of Total IT Cost Allocated to Capital Costs decreased by 16 percentage points between 2019 and 2023
- NSPI Capital Costs decreased 5.4% nominally over the past five years (-1.4% CAGR) while Total IT Cost increased 40% nominally over the past five years (8.8% CAGR)

Factors Contributing to Performance

- The trend in reduced allocation of costs to capital is explained by movement of services to the Cloud, resulting in reduced need for IT infrastructure investment (i.e., servers) and a higher proportion of software being offered under a software as a service model. This model contrasts with capital investment for ownership of application software.

Definition: *Percentage of total IT cost (excluding depreciation/amortization) allocated to IT capital cost*

Source: APQC – Benchmarks on Demand - Utility Industry 2024

Summary Observations

- IT is more costly than the industry group median on a per \$1,000 Revenue basis, but less costly on a per Business Entity FTE basis
- NSPI IT Function FTEs serve fewer end users than the industry group median and there are more NSPI IT FTEs per \$1B revenue than the industry group median
- NSPI allocates a similar percentage of IT costs to capital compared to the industry group median



Appendix



Peer Demographics

UPDATED

Peer	Generation Capacity (MW)*					Transmission Lines	Distribution Lines	Total Electric Revenue	Total Electric Plant	Number of Customers
	Thermal	Hydro	Nuclear	Other Renewables	Total	(km)	(km)	(\$000 CAD**)	(\$000 CAD**)	
AES Indiana	2,442			277	2,719	1,389	18,338	2,109,676	9,607,944	523,395
ATCO Ltd.	417	77	-	248	742	11,000	63,503	1,429,000	10,990,000	261,221
Avista Corporation	937	1,156	-	51	2,143	3,635	30,899	1,212,957	7,226,231	413,831
Cleco Power LLC	2,672				2,672	2,424	19,753	1,308,993	7,930,104	294,514
Duke Energy Kentucky, Inc.	1,164	-	-	40	1,174	175	NA	557,667	3,119,885	151,127
Empire District Electric Company	1,316	16	-	148	1,480	2,097	NA	862,298	4,909,785	183,990
EPCOR Utilities Inc.	-	-	-	-	NA	263	6,302	NA	3,135,000	437,930
Evergy Kansas South, Inc.	1,118		590		1,708	4,331	NA	1,068,757	10,153,192	342,910
Evergy Missouri West, Inc.	1,645	5	-	13	1,662	2,615	NA	1,189,488	6,473,552	343,879
Idaho Power Company	1,928	1,894	-	-	3,822	7,643	45,385	2,007,041	9,846,148	625,440
Kentucky Power Company	1,040	-	-	-	1,040	2,105	16,122	763,460	4,551,680	162,742
MDU Resources Group, Inc.	571	-	-	205	776	5,543	7,886	469,275	2,902,109	144,895
Minnesota Power Enterprises, Inc.	941	126	-	612	1,679	4,981	9,088	1,068,143	6,750,431	151,679
Monongahela Power Company	3,093	465	-	12	3,105	3,243	36,397	1,494,158	8,463,277	396,728
New Brunswick Power Corporation	2,225	882	663	2	3,772	6,902	21,829	1,606,000	7,180,000	386,430
Newfoundland Power Inc.	47	98	-	-	145	2,100	9,367	773,863	1,950,000	275,464
Northern Indiana Public Svc Co LLC	2,034	10		1,302	3,346	1,979	18,620	1,785,949	12,094,851	487,082
NorthWestern Corporation	922	466	-	135	1,524	12,730	20,072	1,470,817	7,471,144	467,684
Nova Scotia Power Inc.	1,974	400	-	198	2,572	5,377	27,924	1,632,856	7,791,343	548,633
Otter Tail Power Company	824	4	-	400	1,229	10,123	9,300	611,437	4,082,902	135,435
Saskatchewan Power Corporation	3,824	865	-	856	5,545	14,930	144,768	3,096,000	17,988,000	557,441
Sierra Pacific Power Company	1,488	-	-	20	1,508	4,051	15,289	1,537,269	6,385,730	375,780
Southern Indiana Gas and Electric Co.	724	-	-	57	781	1,833	11,402	770,031	4,595,611	155,182
TransAlta Corporation	4,572	923	-	2,893	8,388	NA	NA	NA	NA	NA
Westar Energy (KPL)	3,414				3,414	5,992	NA	1,136,646	11,795,361	395,750
Wisconsin Public Service Corporation	2,612	81	-	521	3,214	NA	36,210	1,634,974	7,799,721	463,129

Notes: *Current operating capacity, not nameplate

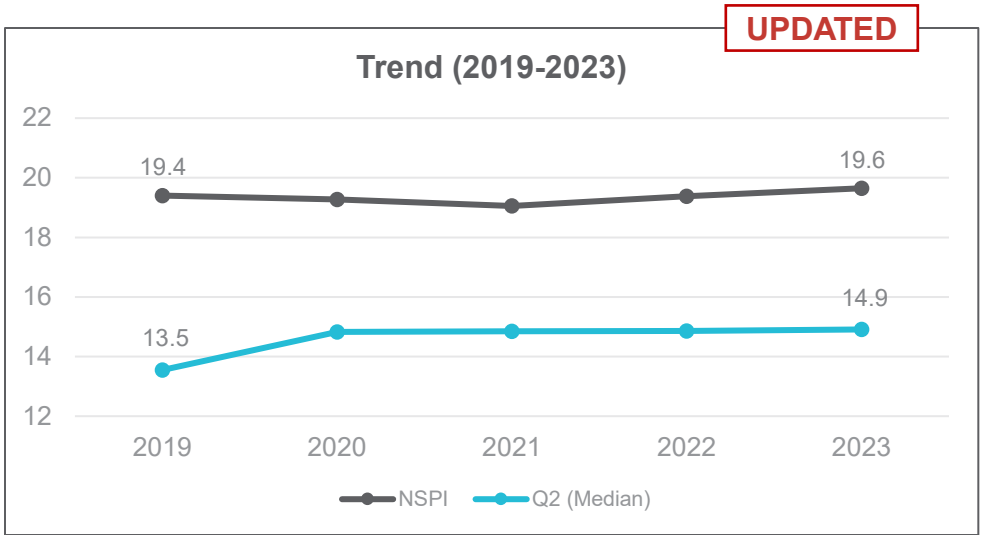
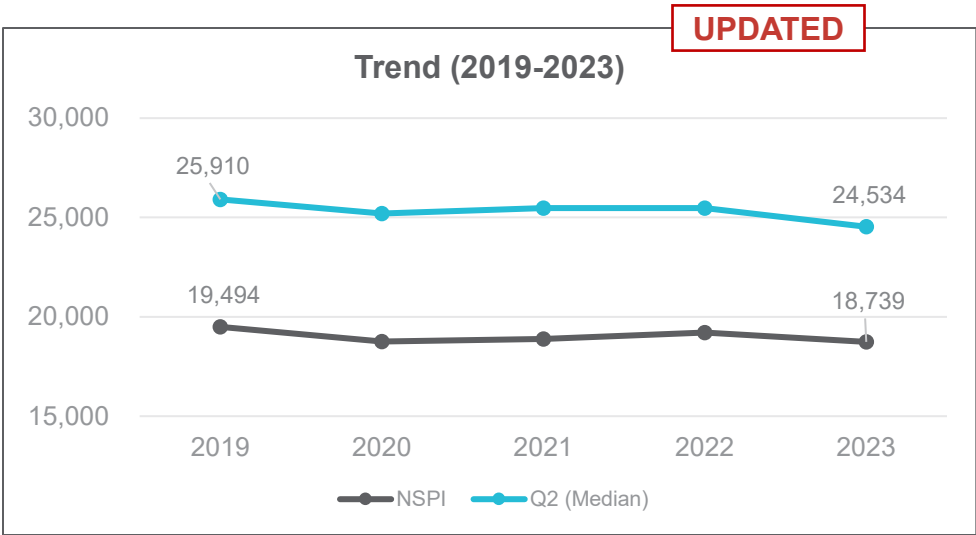
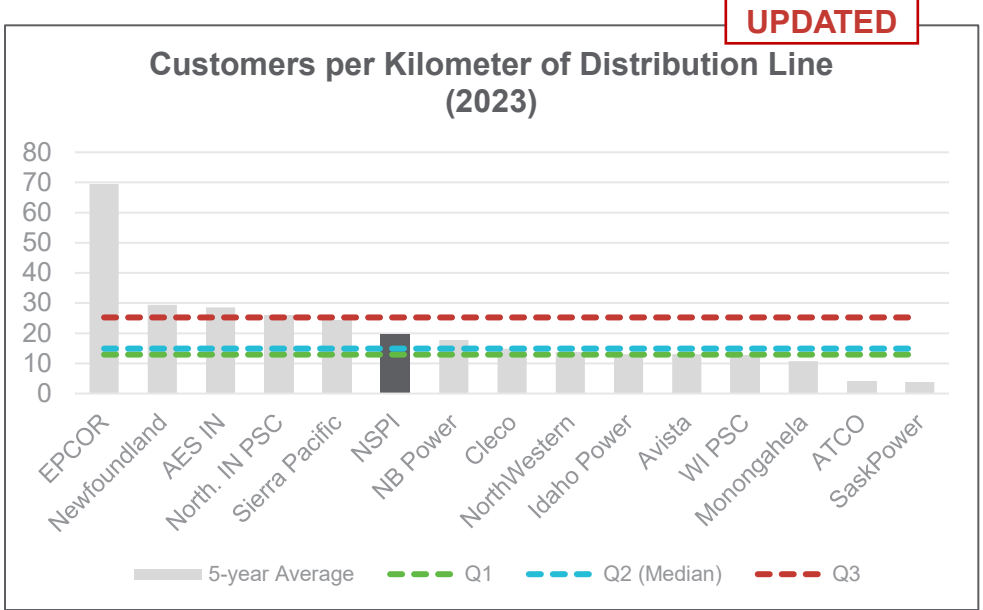
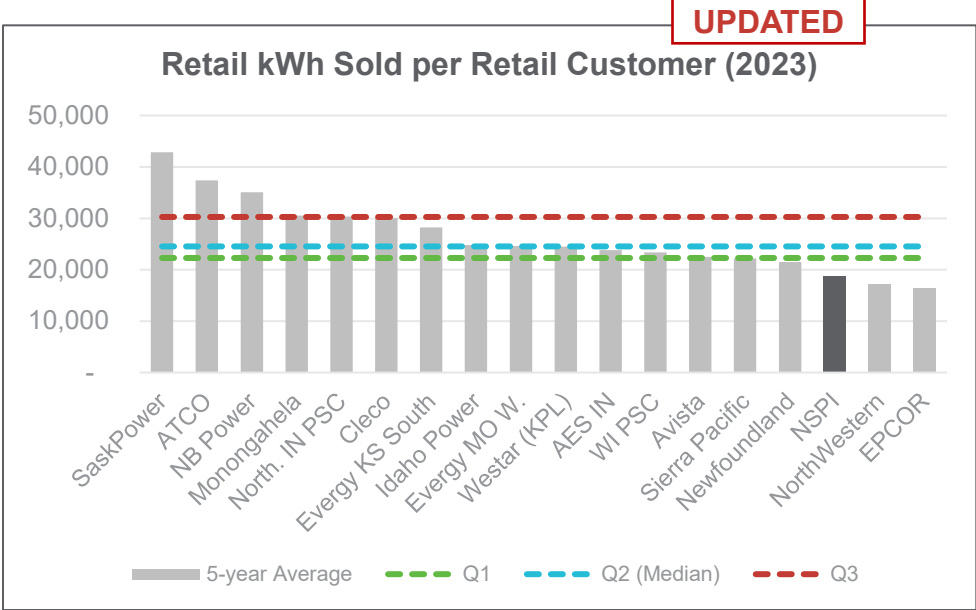
**CAD/USD conversion (0.7407)

NA indicates not available

Source: S&P Global Market Intelligence

Peer Demographics (Cont'd)

NSPI has less energy usage per customer and more customers per kilometer (i.e., higher density) versus peers.



Subcritical Coal-Fired Steam Turbines

NSPI Power Plants

Lingan 1-4

Point Tupper 2

Trenton Pictou

Power Plant	Unit	Generation Technology	Tech. Detail	Nameplate Capacity (MW)	Current Operating Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Year in Service	Region	Sub-Region	State
Dave Johnston	2	Steam Turbine	Subcritical	133.6	106.0	Subbituminous Coal	Distillate Fuel Oil	1961	WECC	NWPP	WY
Erickson	1	Steam Turbine	Subcritical	154.7	156.1	Subbituminous Coal	Distillate Fuel Oil	1973	RFC	R-MISO	MI
Hayden	1	Steam Turbine	Subcritical	190.0	179.0	Subbituminous Coal	Natural Gas	1965	WECC	RMPA	CO
John Twitty	ST1	Steam Turbine	Subcritical	194.0	184.0	Subbituminous Coal	Natural Gas	1976	MRO	MRO-US	MO
Lawrence	4	Steam Turbine	Subcritical	114.0	111.3	Subbituminous Coal	Natural Gas	1960	MRO	MRO-US	KS
Martin Drake Plant	7	Steam Turbine	Subcritical	132.3	131.0	Subbituminous Coal	Natural Gas	1974	WECC	RMPA	CO
Merrimack	1	Steam Turbine	Subcritical	113.6	108.0	Subbituminous Coal	Distillate Fuel Oil	1960	NPCC	NE	NH
Muscatine	9	Steam Turbine	Subcritical	175.5	160.8	Subbituminous Coal	Distillate Fuel Oil	1983	MRO	MRO-US	IA
Naughton	1	Steam Turbine	Subcritical	192.0	156.0	Subbituminous Coal	Natural Gas	1963	WECC	NWPP	WY
North Omaha	4	Steam Turbine	Subcritical	136.0	117.7	Subbituminous Coal	Natural Gas	1963	MRO	MRO-US	NE
Platte	1	Steam Turbine	Subcritical	109.8	100.0	Subbituminous Coal	Distillate Fuel Oil	1982	MRO	MRO-US	NE
Sheldon	1	Steam Turbine	Subcritical	108.8	104.0	Subbituminous Coal	Natural Gas	1961	MRO	MRO-US	NE
Sheldon	2	Steam Turbine	Subcritical	119.9	112.0	Subbituminous Coal	Natural Gas	1968	MRO	MRO-US	NE
Warrick	1	Steam Turbine	Subcritical	166.6	155.4	Subbituminous Coal	Natural Gas	1960	RFC	R-MISO	IN
Warrick	2	Steam Turbine	Subcritical	166.6	157.5	Subbituminous Coal	Natural Gas	1964	RFC	R-MISO	IN
Warrick	3	Steam Turbine	Subcritical	166.6	151.6	Subbituminous Coal	Natural Gas	1965	RFC	R-MISO	IN

Subcritical Oil and Gas-Fired Steam Turbines

NSPI Power Plants

Tufts Cove 1-3

Power Plant	Unit	Generation Technology	Tech. Detail	Nameplate Capacity (MW)	Current Operating Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Year in Service	Region	Sub-Region	State
Cunningham	2	Steam Turbine	Subcritical	190.4	183.0	Natural Gas		1965	MRO	MRO-US	NM
Fort Churchill	1	Steam Turbine	Subcritical	115.0	113.0	Natural Gas		1968	WECC	NWPP	NV
Fort Churchill	2	Steam Turbine	Subcritical	115.0	113.0	Natural Gas		1971	WECC	NWPP	NV
Maddox	1	Steam Turbine	Subcritical	113.6	112.0	Natural Gas		1967	MRO	MRO-US	NM
Natrium	GEN7	Steam Turbine	Subcritical	82.0	82.0	Natural Gas		1966	RFC	R-PJM	WV
Tracy ST	3	Steam Turbine	Subcritical	119.8	108.0	Natural Gas		1974	WECC	NWPP	NV
Valley ST	1	Steam Turbine	Subcritical	136.0	124.7	Natural Gas		1968	RFC	R-MISO	WI
Valley ST	2	Steam Turbine	Subcritical	136.0	140.1	Natural Gas		1969	RFC	R-MISO	WI

Coal-Fired Fluidized Bed Reactors

NSPI Power Plants

Point Aconi 1

Power Plant	Unit	Generation Technology	Tech. Detail	Nameplate Capacity (MW)	Current Operating Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Year in Service	Region	Sub-Region	State
Marion	1	Steam Turbine	Fluidized Bed	33.0	40.0	Bituminous Coal	Distillate Fuel Oil	1963	SERC	GATEWAY	IL
Decatur	GEN2	Steam Turbine	Fluidized Bed	31.0	31.0	Bituminous Coal	Subbituminous Coal	1987	SERC	GATEWAY	IL
Decatur	GEN3	Steam Turbine	Fluidized Bed	31.0	31.0	Bituminous Coal	Subbituminous Coal	1987	SERC	GATEWAY	IL
Decatur	GEN4	Steam Turbine	Fluidized Bed	31.0	31.0	Bituminous Coal	Subbituminous Coal	1987	SERC	GATEWAY	IL
Decatur	GEN5	Steam Turbine	Fluidized Bed	31.0	31.0	Bituminous Coal	Subbituminous Coal	1987	SERC	GATEWAY	IL
Decatur	GEN6	Steam Turbine	Fluidized Bed	31.0	31.0	Bituminous Coal	Subbituminous Coal	1994	SERC	GATEWAY	IL
Decatur	GEN7	Steam Turbine	Fluidized Bed	75.0	75.0	Bituminous Coal	Subbituminous Coal	1997	SERC	GATEWAY	IL
Decatur Cogeneration	GEN1	Steam Turbine	Fluidized Bed	64.8	62.0	Bituminous Coal	Natural Gas	1989	SERC	GATEWAY	IL
Cedar Rapids	GEN2	Steam Turbine	Fluidized Bed	31.0	31.0	Subbituminous Coal	Bituminous Coal	1988	MRO	MRO-US	IA
Cedar Rapids	GEN3	Steam Turbine	Fluidized Bed	31.0	31.0	Subbituminous Coal	Bituminous Coal	1988	MRO	MRO-US	IA
Cedar Rapids	GEN4	Steam Turbine	Fluidized Bed	31.0	31.0	Subbituminous Coal	Bituminous Coal	1988	MRO	MRO-US	IA
Cedar Rapids	GEN5	Steam Turbine	Fluidized Bed	31.0	31.0	Subbituminous Coal	Bituminous Coal	1995	MRO	MRO-US	IA
P.H. Glatfelter Company	GEN5	Steam Turbine	Fluidized Bed	45.9	36.1	Bituminous Coal	Wood Waste Solids	1989	RFC	R-PJM	PA
River Valley Power Plant	GEN1	Steam Turbine	Fluidized Bed	175.0	160.6	Subbituminous Coal	Bituminous Coal	1991	MRO	MRO-US	OK
River Valley Power Plant	GEN2	Steam Turbine	Fluidized Bed	175.0	160.4	Subbituminous Coal	Bituminous Coal	1991	MRO	MRO-US	OK

Gas-Fired Combined Cycle Blocks

NSPI Power Plants

Tufts Cove CC (2x1)

Power Plant	Tech. Type	Current Operating Capacity (MW)	Fuel Type	Year in Service	Region	Sub-Region
Arapahoe CC	Combined Cycle	127	Gas	2000	WECC	RMPA
Beatrice	Combined Cycle	220	Gas	2005	MRO	MRO-US
Berkshire Power	Combined Cycle	246	Gas	1999	NPCC	NE
BHCI Facility (Pueblo)	Combined Cycle	188	Gas	2012	WECC	RMPA
Dighton	Combined Cycle	190	Gas	1999	NPCC	NE
Fitzhugh CC	Combined Cycle	172	Gas	2003	MRO	MRO-US
Hog Bayou	Combined Cycle	245	Gas	2001	SERC	SOU
Hunlock Repowering	Combined Cycle	129	Gas	2011	RFC	R-PJM
John R Kelly CC	Combined Cycle	122	Gas	2001	SERC	FP
Malburg Generating	Combined Cycle	139	Gas	2005	WECC	CAMX
Nebo Power Station	Combined Cycle	140	Gas	2004	WECC	NWPP
Pinelawn Power	Combined Cycle	77	Gas	2005	NPCC	NY
Roseville Energy Park	Combined Cycle	162	Gas	2007	WECC	CAMX
Von Raesfeld	Combined Cycle	148	Gas	2005	WECC	CAMX
Woodland CC	Combined Cycle	83	Gas	2003	WECC	CAMX

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1 **Request IR-73:**

2
3 **Reference: Exhibit N-14, OP-03 Attachment 1, ScottMadden Report**

4 **On page 17 it is noted that NS Power's total OM&G increased 23% in nominal terms from**
5 **2019 to 2023 while the peer median decreased 9% in nominal terms over the same period.**
6 **On page 22 it is noted that NS Power transmission OM&G per retail MWh sold increased**
7 **90% in nominal terms while the peer median increased 42%. On page 25 it is noted that NS**
8 **Power distribution OM&G increased 32% in nominal terms while the peer median**
9 **decreased 1%.**

10
11 **(a) Please provide the nominal increase or decrease for NS Power for these three**
12 **measurements if level 3 and 4 storm costs are removed from the calculation.**

13
14 **Response IR-73:**

15
16 **(a) After adjusting to remove level 3 and 4 storms:**

- 17
- 18 • **NS Power's total OM&G increased by 21 percent in nominal terms from 2019 to 2023.**
 - 19
 - 20 • **NS Power transmission OM&G per retail MWh sold increased 89% in nominal terms**
21 **from 2019 to 2023.**
 - 22
 - 23 • **NS Power distribution OM&G increased 23 percent in nominal terms from 2019 to**
24 **2023.**

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Request IR-74:

Reference: Exhibit N-14, OP-03, Attachment 1, ScottMadden Report, p. 28 of 87, Transmission and Distribution Metrics

The report notes: NSPI widened its positive gap in the Distribution OM&G metrics through 2021, but this gap has since narrowed as NSPI’s Distribution OM&G expenses grew faster than its peers since 2021. NSPI had increased storm expenses in 2023. In addition, Distribution OM&G expense increased in 2023 due to customer growth, increased investment in reliability and significant growth in customer requested work.” Does ScottMadden have similar information on storm cost impacts, reliability investments and customer growth for the peer utilities that contributed to their performance? If so, please provide this information.

Response IR-74:

ScottMadden does not have similar information on storm cost impacts and reliability investments. While ScottMadden cannot attest that the change in each company’s reported number of customers is the same as customer growth, it shows this information below.

Company	Percentage Change in Reported Number of Customers
Idaho Power Company	2.57
Sierra Pacific Power Company	1.62
New Brunswick Power Corporation	1.61
EPCOR Utilities, Inc.	1.60
Avista Corporation	1.49
NorthWestern Corporation	1.43
Nova Scotia Power, Inc.	1.19

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Company	Percentage Change in Reported Number of Customers
Evergy Missouri West, Inc.	1.15
Wisconsin Public Service Corporation	0.86
Evergy Kansas South, Inc.	0.79
Westar Energy (KPL)	0.79
AES Indiana	0.77
Saskatchewan Power Corporation	0.76
Northern Indiana Public Service Company, LLC	0.72
Newfoundland Power Inc.	0.59
Cleco Power LLC	0.57
Monongahela Power Company	0.30
ATCO Ltd.	0.15
TransAlta Corporation	N/A

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1 **Request IR-75:**

2
3 **Reference: Exhibit N-14, Op-03 Attachment 1, ScottMadden Report**

4
5 **On page 29 one of the factors contributing to performance is listed as the adoption of unit**
6 **flexible operations. Please explain what the adoption of unit flexible operations is.**

7
8 Response IR-75:

9
10 The adoption of unit flexible operations refers to a shift in how thermal generating units are
11 operated to accommodate the growing share of variable renewable energy, particularly wind.
12 Historically, many of NS Power's thermal units ran in a steady, base-loaded mode. However, with
13 increased renewable penetration, these units are now required to cycle more frequently – starting
14 and stopping to match system demand – and operate at partial loads. This change allows the system
15 to respond dynamically to fluctuations in renewable output but introduces operational challenges.

16
17 Frequent start-ups and shutdowns increase wear and tear on equipment, drive up maintenance
18 costs, and result in higher fuel consumption during start-up phases. In addition to fuel, start-ups
19 also incur elevated chemistry costs, including the use of water treatment chemicals. These impacts
20 are reflected in rising production OM&G costs per MWh generated, as noted in the ScottMadden
21 benchmarking report. Additionally, operating at lower loads reduces thermal efficiency, which
22 further contributes to increased costs. Many failure mechanisms are driven by operating hours
23 rather than energy output, meaning that even low-load operation can contribute to component
24 fatigue.

25
26 In summary, flexible operations are a necessary evolution in system management, enabling
27 integration of renewables while maintaining reliability. However, they come with increased
28 operational costs and efficiency trade-offs that must be carefully managed through strategic
29 investment and planning.

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Request IR-76:

Reference: Exhibit N-14, OP-03, Attachment 1, ScottMadden Report, page 57 of 87, Capital Additions Metrics

- (a) Do the summary observations on NS Power’s capital additions metrics suggest that NS Power’s investment in its system is below average compared to its peers.**
- (b) Might this suggest that NS Power is lagging behind in investments to improve the reliability of its system? Please explain.**

Response IR-76:

- (a) The following responses are based on the updated benchmarking report and refer to “median” instead of “average” since “median” was used in the report.**

By category of investment:

- (i) Overall capital employed, per retail customer, is below the peer median.**
- (ii) NS Power’s five-year average total plant additions are below the peer median, both on a percentage of total electric plant and as a percentage of depreciation expense basis. NS Power’s total plant additions trend is generally in line with the peer group as a percent of total electric plant, and below the peer trend as a percent of depreciation expense.**
- (iii) NS Power’s five-year average total production additions are in line with the peer median, both on a production additions as a percentage of production plant and as a**

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1 percent of depreciation basis, and trending higher than the peer median in the last three
2 years studied.

3
4 (iv) NS Power's five-year average transmission additions are below the peer median, both
5 on a transmission addition as a percent of transmission plant and as a percent of
6 depreciation expense basis, and below the peer median in four of the five years studied.

7
8 (v) NS Power's five-year average distribution additions are higher than the peer median
9 when comparing distribution additions as a percent of distribution plant, but lower than
10 the peer median when comparing distribution additions as a percent of depreciation
11 expense.

12
13 (vi) General plant additions are generally in line with the peer median on a five-year and
14 annual basis.

15
16 (b) The study depicts total investment in each category (e.g. production, transmission, and
17 distribution) and does not examine the type or purpose of the investment, e.g. whether the
18 investment was made to improve the reliability of its system. Additionally, it was not
19 within ScottMadden's scope to judge the reasonableness of NS Power's investments.
20 Multiple regulatory processes are in place (ACE Plan, Five-Year Reliability Plan,
21 Performance Standards) that allow for detailed analysis on the scope and size of NS
22 Power's investment in system reliability.

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1 **Request IR-77:**

2
3 **Reference: Exhibit N-14, Op-03 Attachment 1, ScottMadden Report**

4
5 **On page 64 it is noted that NS Power's HR cost per FTE is 21% higher than the group**
6 **median and has increased 41% in nominal terms between 2019 and 2023. Under factors**
7 **contributing to performance, it is noted that there has been a general shortage of skilled**
8 **trade employees in Canada resulting in increased costs to attract and retain them.**

9
10 **(a) Please provide the median cost per employee using only the Canadian companies in**
11 **the industry group.**

12
13 **(b) If this shortage is not being experienced elsewhere, has NS Power attempted to recruit**
14 **internationally?**

15
16 **(c) If the shortage is being experienced elsewhere, why are NS Power's costs so much**
17 **higher than its peers?**

18
19 **(d) Has NS Power considered a scholarship program where tuition costs are paid by NS**
20 **Power for students who agree to work for NS Power for a given period of time upon**
21 **completion?**

22
23 **Response IR-77:**

24
25 **(a) ScottMadden used metrics available through APQC (American Productivity & Quality**
26 **Center) for the HR analysis. While APCQ lists members on their website, they do not**
27 **specify who participated in each metric. Because of this, ScottMadden cannot provide the**
28 **median cost per employee using only the Canadian companies in the industry group.**

29
30 **(b) There continues to be a significant and ongoing shortage of skilled trade workers both in**
31 **Canada and internationally.**

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1 (c) A recent investment in a new applicant tracking system has equipped the Talent
2 Acquisition team with advanced capabilities for automated candidate screening and
3 matching. This upgrade has significantly streamlined the recruitment process by enabling
4 faster interview scheduling and more efficient communication, thereby improving the
5 overall candidate experience. The system also supports the creation of candidate pipelines
6 and allows individuals to register their resumes even when no current postings match their
7 interests, ensuring a proactive approach to talent engagement and future hiring needs.
8 These enhancements are particularly beneficial for hiring skilled trades professionals,
9 where speed and precision are critical to securing top talent in a competitive market. The
10 system's ability to quickly identify qualified candidates based on certifications, experience,
11 and availability helps reduce time to hire and ensures alignment with operational needs.
12 The team continues to optimize the system's functionality, always leaning towards
13 continuous improvement. Please also refer to NSEB IR-62 (d).
14

15 (d) While the idea of a scholarship for employment program has merit, implementing such an
16 initiative for skilled trades, especially those involving multi-year apprenticeships, can be
17 complex, particularly within unionized environments. The core challenge is the limited
18 availability of skilled trades professionals at any given time. For example, Nova Scotia
19 Community College (NSCC) currently offers only one Utility Line Worker (ULW) class
20 annually, which consistently has limited capacity and a waitlist. NS Power hires many
21 Apprentice Powerline Technicians (PLTs) from this program each year. To address this
22 shortage, NS Power has partnered with NSCC to sponsor a second ULW class at the
23 Sydney Waterfront Campus, beginning in 2026. This initiative will double the number of
24 annual graduates from the program, significantly increasing NS Power's ability to recruit
25 qualified Apprentice PLTs.

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1 **Request IR-78:**

2
3 **Reference: Exhibit N-3, GRA Direct Evidence**

4
5 **On page 35, NS Power states “Information Technology costs per business entity full-time**
6 **equivalent employee is significantly below the utility industry median”.**

7
8 **(a) Please explain the significance of this statement in the context of NS Power’s recent**
9 **cybersecurity incident.**

10
11 **Response IR-78:**

12
13 (a) As stated in response to NSEB IR-11, the ScottMadden work is helpful in that it provides
14 data points to compare and helps validate NS Power’s expenses at a high level. However,
15 the work does not take into account jurisdiction or utility-specific variables and therefore
16 it is likely not appropriate to draw scenario specific conclusions from the work.
17 Furthermore, cybersecurity is a subset of total IT investment. Please refer to OP-03
18 Attachment 1. While “Information Technology costs per business entity full-time
19 equivalent employee is significantly below the utility industry median,” NS Power’s IT
20 costs incurred per \$1000 of revenue is above the industry median. NS Power continues to
21 implement its cyber security roadmap. Please also refer to NSEB IR-64.

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Request IR-79:

Reference: Exhibit N-3 GRA Direct Evidence, 8.6 Regulatory Amortizations

Please provide a breakdown of the unreduced accrued and forecast GRA and COSS Deferral costs included in Figure 8-3 of the application.

Response IR-79:

Please see below:

(\$ million)

Account	2024	2025 Forecast
Consulting	0.5	1.5

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Request IR-80:

Reference: Exhibit N-12, FO-13.

Please provide a breakdown of the “Deferred Charges – Other General” in FO-13 in the same format as in FO-13, but including 2024 compliance and actual amounts, as shown in RB-2-16.

Response IR-80:

Please see the table below:

Deferred Charges- Other General

(\$ million)	2024 GRA Compliance Forecast	2024 Actual
Beginning balance	40.1	34.7
Additions / Adjustments	-	5.1
Less: Amortization	(0.2)	(0.8)
Ending balance	39.9	39.0

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Request IR-81:

Reference: Exhibit N-7, Appendix 8A, Depreciation Study

(a) If the retirement rate method described in Appendix 8A, pages 20-33 of 297, depends on segmentation by age group, and the study ultimately uses judgment based on things such as knowledge of the property and the types of curves estimated for other utilities (operating in different environments) to simulate ages, does that mean the study is heavily influenced by those factors? Please explain.

(b) Is it preferable to apply the retirement rate method when actual aged experience is available? Please explain.

(c) Why wasn't actual aged experience used in this study?

Response IR-81:

(a) The unaged data which include plant additions, retirements and balances by account and transaction year (i.e. fiscal year) are statistically aged using computed mortality. The Computed Mortality method is a recognized industry practice and is described in several authoritative depreciation textbooks. Computed mortality is used to statistically age unaged property records. Computed mortality requires the selection of a dispersion curve (e.g. R1, S2, L4, etc.). The dispersion curve selected is based on informed professional judgement with consideration of the results from the Simulated Plant Record (SPR) Method of Life Analysis and estimates used by NS Power and other electric companies for similar asset groups. The survival pattern for all industrial and utility property can be described by a dispersion curve used in connection with an average service life which is known as a survivor curve. During the statistical aging process, retirements are determined each year by varying the average service life, up or down, until the total simulated retirements each year match the actual unaged retirements for the year. Each year a different survivor curve

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1 solution is determined based on whether the company experienced heavier than normal
2 retirements or not. From the survivor curve, retirement ratios can be applied to the initial
3 plant addition or a beginning aged balance to determine retirements by age or vintage year.
4

- 5 (b) The premise of the question is incorrect. The retirement rate method was used by NS Power
6 to analyze statistically aged data from the period 1942-2023. Aged data for transmission,
7 distribution and general plant were limited to the years 2009 and after.
8

9 Aged data contained in the Company's fixed asset system starts in 2009 with the
10 implementation of new fixed asset software in 2009. The vendor selected by NS Power to
11 implement the fixed asset system is a company used by many other utilities. The challenge
12 facing the vendor and NS Power at the time of implementation is how to determine a
13 starting aged balance by plant account as of 1/1/2009 when such information does not exist.
14 A concise explanation regarding the process performed in 2009 by the company and vendor
15 would be to state that many assumptions were used in developing an aged balance as of
16 1/1/2009. The starting aged balances as of 1/1/2009 developed by the company and the
17 vendor for purposes of setting up a new fixed asset system were not consistent with the
18 simulated aged balances used in NS Power's most recent depreciation study available at
19 the time (i.e., 2006 study). Gannett Fleming's assessment was that the aging of the balance
20 as of 1/1/2009 by the vendor was not as precise as the statistically aged balances used in
21 the depreciation study. The statistically aged data used in the depreciation study are based
22 on the company's historical plant additions and retirements made throughout most of its
23 history. The "aged data" contained in the company's fixed asset system is based on broad
24 assumptions regarding the starting aged balance as of 1/1/2009 made by the Company and
25 vendor to initiate the fixed asset system and these assumptions were not overly concerned
26 with actuarial studies performed in connection with a depreciation study. Based upon
27 experience and discussions with other utility clients, when the actual age (i.e., vintage) of
28 assets was unknown, the vendor used an average age (i.e., a specific vintage year) to assign
29 the costs related to that asset group. For example, if the vendor was informed that the
30 estimated average age of wood poles under 45 feet was 25 years, then all costs for that size

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1 of pole would be assigned one specific vintage, e.g., 1984. Similarly, if the average age of
2 all wood poles 45 feet and greater was 20 years, all costs related to this asset group would
3 be assigned another vintage corresponding with 20 years, e.g., 1989. The simulated aged
4 database used by Gannett Fleming would, in this example, have vintage balances for every
5 year starting with 2008 and going back 50 years or more. This scenario is much more
6 realistic and is based on the company's addition and retirement history.

7
8 Therefore, not all aged databases are the same as some include some broad assumptions
9 when initiating the system and creating the fixed asset database, i.e., starting "aged"
10 balance. The vendor's main concern was installing the fixed asset database for NS Power.
11 The level of precision related to the data needed to perform actuarial analyses was a
12 secondary concern.

- 13
14 (c) Aged data for NS Power as contained in the fixed asset system had limitations from an
15 actuarial perspective and in Gannett Fleming's assessment, the statistically aged data as
16 used in the depreciation study were superior to the aged data contained in the fixed asset
17 system. The statistically aged data used by Gannett Fleming contained many more years of
18 data, 1942-2023 versus 2009-2023. Also, the statistically aged data was the database used
19 in every depreciation study the company has filed with the Board over the past 30 years
20 and to change the database would have potentially brought into play different survivor
21 results that may not be justified simply because another database was used.

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1 **Request IR-82:**

2
3 **Reference: Exhibit N-7, Appendix 8A, Depreciation Study**

4
5 **On page 56 of 297 of the Depreciation Study, Gannett Fleming notes, “Continued**
6 **surveillance and periodic revisions are normally required to maintain continued use of**
7 **appropriate annual depreciation accrual rates.” What periods are normally used for**
8 **revisions?**

9
10 **Response IR-82:**

11
12 Periodic depreciation studies typically are performed every three to five years, depending on the
13 utility, industry and jurisdiction involved.

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Request IR-83:

Reference: Exhibit N-7, Appendix 8A, Depreciation Study

On page 54 of 297 of Appendix 8A, Gannett Fleming recommends that reserve imbalances for the five general plant accounts subject to amortization accounting be amortized over a five-year period.

(a) What is a reserve imbalance and what causes it?

(b) Please confirm, or explain otherwise, that the proposed reserve imbalance to be recovered over five years is \$26,114,146, as shown below:

391.10 Furniture and Equipment	(919,412)
391.31 Computer Equipment - Hardware	416,440
391.32 Computer Software	22,338,881
394.00 Shop Equipment	180,288
398.00 Miscellaneous Equipment	3,178,537
Total	26,114,146

(c) What costs or other benefits do ratepayers derive from the adoption of amortization accounting compared to the annual incremental depreciation expense of \$600,000 over the test year period that NS Power notes on page 42 of the application?

(d) Please confirm, or clarify otherwise, that this requires no changes to NS Power's accounting policies if approved.

(i) If not confirmed, please provide the proposed revised accounting policy.

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1 Response IR-83:

2
3 (a) The reserve imbalance is the difference between the book reserve (a.k.a., accumulated
4 depreciation) and the theoretical reserve (a.k.a., calculated accrued depreciation). The
5 reserve imbalance is caused by plant and reserve activity that is different than what the
6 models (i.e., depreciation parameters) forecasted. For example, if a company owned one
7 backhoe, and the backhoe was being depreciated over an average service life of 10 years,
8 but it was not retired until age 12, the company would have recovered through past
9 depreciation expense, 20 percent more than the backhoe's original cost. Or, alternatively,
10 if the net salvage estimate for the backhoe was zero percent and at the time of its retirement,
11 20 percent salvage was received for the backhoe, then the company recovered 20 percent
12 less than what the model expected through past depreciation expense. This is a simplified
13 example used for illustration purposes.
14

15 (b) The amounts listed in the above table for the five general plant accounts subject to
16 amortization are the reserve imbalances for each account. The reserve imbalance is the
17 difference between the book reserve and the theoretical reserve. The theoretical reserve is
18 the amount that should have been collected based on the age of the asset and the selected
19 amortization related to these five general plant accounts. The theoretical reserve is used as
20 a benchmark to assess the adequacy of the company's book reserve. Any difference
21 between the two is trued up prospectively over a reasonable amortization period. A five-
22 year amortization period was deemed appropriate as most of the reserve imbalance is
23 related to computer hardware and software which has a remaining life of approximately
24 five years.
25

26 (c) Using amortization accounting, the cost of the asset is allocated over a decided time frame
27 – usually a period consistent with its expected service life. The asset is retired and removed
28 from the books once it has been fully amortized, regardless of whether it is rendering
29 service.

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1 Under group depreciation accounting used by most utilities, an item continues to be
2 depreciated until it has been removed from the books through retirement. Depreciation
3 continues until an asset is retired regardless of the age of the asset and whether it has been
4 fully accrued already.

5
6 The asset groups subject to amortization accounting consist of numerous units of property,
7 often of modest original individual cost, at least when compared with units in asset groups
8 in other categories. Property of this type tends to have a relatively short useful life. The
9 amortization method is a cost-effective way to manage the recovery of these numerous,
10 low-unit cost assets, without the administrative overhead associated with depreciation and
11 retirement work order process employed for lower turnover, higher cost, more stable assets.
12 The accounting effort of tracking numerous, low unit-cost assets is much less, without any
13 material reduction in accounting accuracy.

14
15 Many electric utilities in North America have received regulatory approval to adopt
16 amortization accounting for these groups within general plant. Examples include
17 Newfoundland Power, BC Hydro, CentraGas Alberta, UGI Utilities Inc. – Electric
18 Division, and West Penn Power Co. The U.S. Federal Energy Regulatory Commission
19 (FERC) through its Accounting Release 15 has also accepted the use of amortization
20 accounting for these groups.

21
22 (d) Confirmed. NS Power does not anticipate that the approval of amortization accounting for
23 these general plant asset groups would require a change to the Company's accounting
24 policies.

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Request IR-84:

Reference: Reference: Exhibit N-7, Appendix 8A, Depreciation Study

Appendix 8A, Depreciation Study, Part VI – Table 1 (pages 58-60 of 297) and Part IX (Detailed Depreciation Calculations)

(a) Please explain how the “original cost” as of December 31, 2023, in the tables in the Depreciation Study was determined.

(b) Please explain how the “book reserve” as of December 31, 2023, in the tables in the Depreciation Study was determined.

(c) Please explain how the “calculated accrued” amount as of December 31, 2023, in the tables in Part IX of the Depreciation Study was determined.

(d) Please explain how the “future accruals” amount as of December 31, 2023, in the tables in the Depreciation Study was determined.

(e) Please reconcile the December 31, 2023, amounts for “original cost”, “book reserve”, “calculated accrued” and “future accruals” with the beginning balances for the 2024 actual amounts in the continuity schedule in RB-01.

(f) Using Ligan 2 as an example (Part IX in the Depreciation Study, page 200 of 297):

(i) Please explain why the \$0.7 million future book accrual does not appear to be the difference between the original cost of \$86.8 million and either the calculated accrued amount of \$81.6 million, and the allocated book reserve of \$100 million.

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1 (ii) **Please explain why the allocated book reserve exceeds the original cost by**
2 **\$13.2 million.**

3
4 (g) **Please explain why an interim survivor curve was used for production plant, but not**
5 **for all other plant?**

6
7 Response IR-84:

8
9 (a) The original cost amounts listed in Part IX of Appendix 8A (Depreciation Study Report)
10 are simulated aged balances determined using Computed Mortality. The electric plant
11 assets are listed at their original cost when first installed or purchased. This is the standard
12 accounting convention for fixed assets such as electric plant.

13
14 (b) The book reserve amounts are the company's accumulated depreciation listed by plant
15 account (a.k.a., asset groups). The book reserve amounts tie to NS Power's financial
16 statements.

17
18 (c) The calculated accrued depreciation (CAD) at the vintage level is determined as follows:
19 *Surviving Original Cost (\$) multiplied by the CAD ratio (CADR).*

20
21 The CADR is determined by the equation $[1 - (RL_{(x)} / ASL)]$, where $RL_{(x)}$ is the remaining
22 life at age x and ASL is the account's estimated average service life. Under the ELG
23 procedure, the terms $RL_{(x)}$ and ASL apply to each equal life group (within a vintage year)
24 rather than the total vintage group. The size of each equal life group is determined from
25 the survivor curve. The $CADR_{(x)}$, using ELG, simplifies to the equation: *Age / Average*
26 *Service Life*, since there is no dispersion of lives within an equal life group. The CAD for
27 the vintage group is determined by summing the CAD for each equal life group remaining
28 in service.

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1 (d) The future accruals represent the service value of the assets left to be recovered through
2 future depreciation accruals. The future accruals are the asset's original cost less future net
3 salvage less book reserve.

4
5 (e) Please refer to Attachment 1.

6
7 (f) (i) Future accruals are the original cost [\$86,836,520.77] less future net salvage
8 [(\$86,836,520.77 * FNS % or -16% = \$-13,893,843)] less book reserve [\$100,062,274].
9 The future accruals total \$668,090.

10
11 (ii.) The book reserve contains a provision for future net salvage (FNS).

12
13 (g) An interim survivor curve is a truncated survivor curve. An interim survivor curve, used
14 in connection with an estimated probable retirement date (i.e., terminal date), is typically
15 used for large facilities, such as a power plant. These facilities are referred to as life span
16 property. A characteristic of life span property is that a large portion of the investment
17 related to a facility will be retired concurrently.

18
19 In contrast to life span property is mass property. Mass property, such as utility poles, are
20 replaced each year at a rate of 1 to 3 percent of the total population each year. The mass
21 property plant accounts include most transmission, distribution and general plant accounts.
22 A survivor curve (not truncated) is used to describe the service life characteristics of mass
23 property.

2026-2027 GRA NSEB IR-84 Attachment 1 has been filed electronically.

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1 **Request IR-85:**

2
3 **Reference: Exhibit N-7, Appendix 8E**

- 4
5 **(a) Please explain the difference between the estimated costs to fully decommission NS**
6 **Power's hydroelectric system on page 18 of 33 of Appendix 8B and page 14 of 129 of**
7 **Appendix 8C, and the summary of hydro decommissioning costs in Appendix 8E.**
8
9 **(b) Please provide a detailed breakdown of the of the work and costs by component, that**
10 **have been removed from the "full" decommissioning costs to determine the "partial"**
11 **decommissioning costs?**
12
13 **(c) Please provide all information and documentation that supports any claim that NS**
14 **Power will not be required to undertake "full" decommissioning of the hydro sites.**
15
16 **(d) Please provide NS Power's justification for putting future customers and**
17 **shareholders at risk of bearing responsibility for a disproportionate share of**
18 **decommissioning costs should full decommissioning be required.**
19

20 **Response:**

- 21
22 **(a) With the exception of decommissioning costs for Tuskett hydro system, the full**
23 **decommissioning costs in the summary of hydro decommissioning costs in Appendix 8E**
24 **are the combination of the estimated infrastructure removal, environmental, and sediment**
25 **management costs contained in Appendix 08B and the estimated costs of archaeological**
26 **work that may be required during the removal of hydroelectric assets owned by NS Power**
27 **contained in Appendix 08C. Tuskett hydro system has a separate estimate due to the**
28 **additional, more detailed engineering estimates that have been completed by NS Power as**
29 **part of the economic analysis associated with the Tuskett Main Dam Refurbishment project.**
30 **Please see Confidential Attachment 1.**

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1 (b) Please refer to Confidential Attachment 1 that provides the scope of work for the partial
2 decommissioning costs. This was not determined by taking the scope of work for full
3 decommissioning activities and adjusting for a partial decommissioning scope of work.
4 The partial decommissioning utilized an assumption that water management and retaining
5 structures would all remain in place with only decommissioning assets directly used for
6 power generation. This approach represents the lowest estimate of partial decommissioning
7 as it does not include any work on the civil aspects of the hydro systems which drive most
8 of the decommissioning costs. The partial decommissioning costs for these systems
9 (Turbines, Generators, Electrical, etc) as outlined in Confidential Attachment 1 were
10 escalated from 2018 costs to the 2024 dollars at the rate determined by Hatch. Costs for
11 archaeological reconnaissance, shovel testing and monitoring per the Boreas report
12 (Appendix 08C) were then added to the partial infrastructure removal costs to calculate the
13 total partial decommissioning expense. Tusket hydro system has a separate estimate due to
14 the additional, more detailed engineering estimates that have been completed by NS Power
15 as part of the economic analysis associated with the Tusket Main Dam Refurbishment
16 project.

17
18 Please note that hydro reconnaissance costs have been removed from the partial
19 decommissioning costs per the terms of the GRA settlement agreement reached between
20 NS Power and customer representatives.

21
22 (c-d) The rationale and justification for not including decommissioning costs at this time is
23 included in s. 8.5 of the GRA, where it states: “Given the magnitude of these costs and the
24 broad policy, societal, and environmental considerations and factors that would need to be
25 taken into account to decommission such sites, NS Power believes removing these costs
26 from customer rates, at this time, is a reasonable approach to balancing cost recovery and
27 rate pressure for customers.”

28
29 As indicated in s. 8.5, these hydro assets are unique utility assets. What makes them unique
30 is the significant costs that must be invested in them regardless of their future use and the

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1 relatively disproportionate output. Perhaps most importantly, the role they play within
2 Nova Scotia's social, economic, environmental, and political framework is what truly
3 makes them unique and why any decision regarding their decommissioning would require
4 consideration of a broad range of parties, perspectives, and factors. As stated in s. 8.5, until
5 that broader discussion has occurred and there is a better understanding of the likelihood
6 and extent of decommissioning, NS Power believes its proposed approach of not including
7 such costs in customer rates at this time is a reasonable approach to mitigate rate pressure
8 for customers.

9
10 NS Power recognizes the Board's concern regarding intergenerational equity. It is one
11 shared by NS Power; however, NS Power believes the proposed approach to remove these
12 costs from revenue requirement until there is greater certainty as to whether there is a
13 realistic possibility they will be incurred is a measured and responsible approach that helps
14 to ensure rates are just and reasonable. In making this proposal, NS Power has initiated
15 the broader discussion that is necessary to arrive at a future approach for these assets that
16 considers and takes into account all stakeholders and their perspectives. If this broader
17 discussion demonstrates decommissioning of these assets is a potential path or option, then
18 the relevant costs can be included in the revenue requirement to be approved in NS Power's
19 next general rate application. However, NS Power believes the approach balances the
20 interests of both current and future customers by ensuring there is more clarity about
21 whether such costs would be incurred, before customers are asked to pay for them.

**2026-2027 GRA NSEB IR-85 Confidential Attachment 1
has been removed due to confidentiality.**

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1 **Request IR-86:**

2
3 **Reference: Exhibit N-7, Appendix 8E**

4
5 **NS Power notes it has excluded the costs of decommissioning the Wreck Cove, Mersey and**
6 **Tusket hydroelectric assets from the proposed depreciation rates.**

7
8 **(a) Please reconcile the decommissioning costs on page 44 of the application, lines 8-10**
9 **and footnote 3, with the full and partial decommissioning costs in Appendix 8E.**

10
11 **(b) Please provide all information and documentation that supports any claim that NS**
12 **Power will not be required to decommission these sites.**

13
14 **(c) How does removing these costs from rates balance cost recovery and rate pressure**
15 **for customers when there is no recovery of the decommissioning costs?**

16
17 **(d) Please provide NS Power's justification for putting future customers at risk of**
18 **bearing responsibility for a disproportionate share of decommissioning costs for these**
19 **facilities.**

20
21 **(e) Please explain how the 80% renewable electricity standard justifies the assumption**
22 **that these assets will be operated in perpetuity and never decommissioned.**

23
24 **(f) Please confirm, or explain otherwise, that it is NS Power's position, for the reasons**
25 **set out in part 8.5 of its application, that it will never be required to decommission the**
26 **Wreck Cove, Tusket or Mersey systems.**

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1 Response IR-86:

2
3 (a) The decommissioning costs on page 44 of the application, lines 8-10 and footnote 3 were
4 determined by taking the partial and full decommissioning costs presented in 2024 dollars
5 in Appendix 08E and escalating to future values at an assumed inflation rate of 2 percent.
6 The potential retirement years used for this calculation are 2066 for Tusket, 2070 for Wreck
7 Cove, and 2091 for Mersey.

8
9 (b-f) Please see NSEB IR-85 (c) – (d).

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Request IR-87:

Reference: Appendix 8G, Depreciation Settlement Agreement

(a) Please confirm, or explain otherwise, that the net effect of the settlement agreement reduces the future accrual amount from the Depreciation Study by \$416 million.

(b) Please confirm, or explain otherwise, that the net effect of the settlement agreement reduces the annual accrual amount from the Depreciation Study by \$19.5 million.

(c) Please quantify the impact of each of the following in contributing to the changes noted in (a) and (b)

(i) Removal of reconnaissance costs included in the Hydro Decommissioning estimates.

(ii) Removal of contingency costs from generation decommissioning estimates.

(iii) Reflecting forecast decommissioning costs for all Generation Plant in 2024 dollars (removal of inflation to forecast year of decommissioning).

(iv) Updating estimated service life of Account 353 - Transmission Station Equipment to 48-R2.5.

(v) Updating estimated service life of Account 390.10 - General Plant Structures and Improvements to 43-R3.

(vi) Reducing the Net Salvage Rate for Account 354.00 - Transmission Towers and Fixtures from (40%) to (20%).

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**(vii) Reducing the Net Salvage Rate for Account 355.00 -
Transmission Poles and Fixtures from (60%) to (20%).**

**(viii) Reducing the Net Salvage Rate for Account 365.00 - Distribution
Overhead Conductors and Devices from (30%) to (26%).**

**(d) Please explain the reason for the changes in the annual accrual amounts in Table 1
under the settlement agreement (Appendix 8G) from the Distribution Study
(Appendix 8A, pages 58-60 of 297) for the following items and why no changes were
made to future accruals:**

(i) 350.10 – Transmission Plant, Land Rights – Easements

(ii) 360.10 – Distribution Plant, Land Rights – Easements, Surveys and Clearing

(iii) 364.00 – Distribution Plant, – Poles, Towers and Fixtures

(iv) 367.00 – Distribution Plant, Underground Conductors and Devices

(v) 368.00 – Distribution Plant, Line Transformers

(vi) 369.00 – Distribution Plant, Services

(vii) 370.10 – Distribution Plant, Meters – AMI

(viii) 373.00 – Distribution Plant, Street Lighting and Signal Systems

(ix) 373.10 – Distribution Plant, Street Lighting and Signal Systems – LED

(x) 392.00 – General Plant, Transportation Equipment

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(xi) 397.00 – General Plant, Communication Equipment

Response IR-87:

(a) Confirmed.

(b) Based on the property, plant and equipment balances at Dec. 31, 2023, this is correct. When applying the proposed depreciation rates to NS Power's forecast property, plant and equipment balances during the test period, depreciation and accretion expense decreases by \$19.1 million in 2026 and \$20.8 million in 2027 as a result of the settlement agreement.

(c) (i-iii) NS Power has not calculated the impact of these items separately in preparation of the adjusted revenue requirement due to the settlement agreement. The decrease in depreciation rates due to the removal of hydro reconnaissance costs, removal of contingency costs from generation decommissioning estimates and removal of inflation to the year of retirement results in a forecast depreciation and accretion expense reduction of \$10.6 million reduction in 2026 and a \$11.7 million reduction in 2027.

(iv) A reduction of \$1.8 million in 2026 and a reduction of \$2.0 million in 2027.

(v) A reduction of \$0.2 million in 2026 and a reduction of \$0.3 million in 2027.

(vi) A reduction of \$0.8 million in 2026 and a reduction of \$0.9 million in 2027.

(vii) A reduction of \$5.0 million in 2026 and a reduction of \$5.3 million in 2027.

(viii) A reduction of \$0.7 million in both 2026 and 2027.

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1 (d) Appendix 8A, pages 58-60, Table 1 presents a summary of the detailed depreciation
2 calculations which are set forth in Part IX of Appendix 8A. The amounts in Table 1 and
3 Part IX should agree. However, there were small numerical errors in Table 1 caused by
4 using a superseded version of Table 1 in Appendix 8A. The error was related to a very
5 small portion of the plant balance in which there was no indication of when the asset was
6 initially recorded to the books nor an indication of its age. The average age of the account
7 was used initially for this minor pool of assets until more specific information regarding
8 its age became available. The depreciation summary table (Table 1) presented in Appendix
9 8G agrees with the detailed depreciation calculations listing the amounts by plant account
10 and vintage year.

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1 **Request IR-88:**

2
3 **Reference: Exhibit N-5, Appendix 3A, p. 5**

4
5 **NS Power states it intends to file an application seeking approval to decommission the**
6 **Annapolis Tidal Generation Facility in 2026 and recover the remaining net book value over**
7 **ten years, including \$2.6 million in the proposed 2027 revenue requirement.**

8
9 **(a) When in 2026 is this application expected to be filed?**

10
11 **(b) Please confirm that approval of the decommissioning and any amortization period**
12 **will be subject to determination in that proceeding, notwithstanding what NS Power**
13 **has forecast for its 2027 revenue requirement.**

14
15 **Response IR-88:**

16
17 **(a) NS Power anticipates filing an application with the NSEB in Q4 2026.**

18
19 **(b) Confirmed. NS Power anticipates that the capital costs required to decommission the**
20 **Annapolis Tidal Generating Facility will be amortized over a period determined as part of**
21 **the Company's capital application and, subject to a Board decision in the matter, that**
22 **recovery of those costs will begin once decommissioning is complete.**

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Request IR-89:

Reference: Exhibit N-3 GRA Direct Evidence, Section 9.2.1 Average Capital Assets

On pages 52-53 of its application, NS Power notes that it has removed approximately \$700 million from its rate base for the DDA assets (Point Aconi, Trenton, Point Tupper Marine Terminal, Sydney International Coal Pier, and steam general assets) on the basis that securitization will be in place for these assets by January 1, 2026, and requests that its recovery of depreciation and its return on these assets be deferred on an “interim” basis if securitization is delayed.

(a) Please provide all information and documentation that supports NS Power’s belief that securitization will be in place by January 1, 2026.

(b) What is NS Power’s present expectation around the likelihood and timing of securitization, including NS Power’s separate application to the Board?

(c) Please provide an update on the status of resolution of outstanding issues related to securitization (such as credit rating agency processes, trust indenture, tax).

(d) If the depreciation expense and financing costs of the assets end up being deferred if the securitization is delayed, is NS Power’s intention to defer these costs until its next GRA proceeding?

(i) What is the estimated cost of the deferral, in terms of return, for 2026 and 2027?

(e) On page 50 (lines 1-3) of the application, it implies that the securitization may occur in two debt issuances, one for \$500 million in 2025 and another for \$204 million in

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1 **2026. Please confirm if that is the case and, if so, explain why this is being done in two**
2 **traunches [sic].**

3
4 **(f) If the securitization is being done in two issuances, please breakdown a comparison**
5 **of the extra costs (financing fees, accounting fees, legal fees, etc.) that will be incurred**
6 **by proceeding in two separate debt issuances instead of one.**

7
8 Response IR-89:

9
10 (a-b) NS Power's belief that securitization would be in place by January 1, 2026 was predicated
11 on the assumption that enabling regulations would be in place by the end of Q3 2025. As
12 enabling regulations are not yet in place, NS Power now anticipates a securitization
13 application to the Board in Q4 2025, with securitization in place by the end of Q1 2026.

14
15 (c) NS Power believes it has adequately addressed these issues, such that it will be able to
16 proceed with a securitization application as soon as enabling regulations are in place.

17
18 (d) No, it is not NS Power's intention to defer these costs until its next GRA proceeding.
19 Rather, the deferred costs would be added to the balance being securitized.

20
21 (i) Not applicable.

22
23 (e) The application contemplated two separate issuances as NS Power was still in the process
24 of investigating whether there was likely to be sufficient market interest to support issuing
25 \$700 million at one time. Based on NS Power's continued engagement with its financial
26 advisor, it now anticipates that there will be sufficient market interest, such that only one
27 issuance will be required.

28
29 (f) Not applicable.

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1 **Request IR-90:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 9.2.5.6 Retired Assets**

4
5 **Please provide a breakdown of the “\$1.7 million related to the unrecovered net book value**
6 **of certain retired Smart Grid Nova Scotia assets” stated on page 58 of 99.**

7
8 **Response IR-90:**

9
10 **NS Power’s Smart Grid Nova Scotia Project – Asset Disposition Filing provided the following:**

11
12 As described in Section 2, the unrecovered NBV of the DERMS asset is
13 \$1,116,651. These assets were included in depreciation pool 7800 – Computer
14 Software, but tracked separately for reporting purposes to the Board. Further, the
15 cost of the EV Chargers, ev.energy platform, Coritech bi-directional charger and
16 Fermata bi-directional charger were all accumulated in the 8300 – EV Charger
17 depreciation pool. As NS Power is expected to retire, in the case of the Coritech
18 Charger, or has retired all assets within the 8300 – EV Charger depreciation pool,
19 the total unrecovered net book value associated with these assets as of February 28,
20 2025 is \$541,113 after transfer to the NSCC.¹

21
22 The total amount of the unrecovered netbook value (NBV) of the Smart Grid Nova Scotia assets
23 is comprised of the DERMS (\$1,116,651), EV Chargers, ev.energy platform, Coritech and Fermata
24 bi-directional chargers (\$541,113), which equal \$1,657,764 or \$1.7 million rounded up.

¹ NS Power, Smart Grid Nova Scotia Project – Asset Disposition Filing, April 4, 2025, p.14, lines 7-14.

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Request IR-91:

Reference: Exhibit N-12, FO-15 Working Capital

(a) Where does the forecast for customer deposits tie to in the forecast financial statements?

(b) Why have customer deposits decreased by approximately 50% in 2026 and 2027 over the 2024 test year forecast?

Response IR-91:

(a) Customer deposits are included in the line item “Accounts payable and accruals” on NS Power’s regulated balance sheet which can be seen in FO-02, line 30.

(b) NS Power collects customer deposits as a form of security on new customer accounts. Customers can complete a personal credit check through Equifax Canada, provide a reference letter from another utility showing payments were made on time, or provide a security deposit equal to three months of estimated service cost. Deposits are returned, with interest, upon closure of the account, or after two years of satisfactory payment history, whichever comes first.

NS Power’s actual customer deposits were significantly lower than what was forecast in the 2024 GRA Compliance budget, with a year-end balance of \$12.5 million. Generally, NS Power has seen a decrease in customer deposits held by the Company over the last number of years, as seen in the table below:

Customer Deposits and Accrued Interest at December 31 (\$ million) ²⁷					
Year	2020	2021	2022	2023	2024 ²⁸
Amount	18.3	16.9	15.1	12.5	12.6

A number of factors have driven this decrease:

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- The number of customers self-identifying as low-income has increased significantly. Inflationary pressures are likely contributing to this increase. NS Power can waive security deposits for low-income customers.
- Nova Scotia has experienced higher levels of interprovincial migration. Many of these new customers already have an established credit history, thus not requiring a security deposit.

While interprovincial migration has slowed, it is reasonable to anticipate that the rising cost of living will continue to drive customers to seek relief from security deposits when necessary. NS Power remains committed to working with low-income customers and their advocates to provide support where appropriate.

NS Power has forecast this trend of reduced customer deposits to continue with forecast balances of \$11.0 million, \$9.9 million and \$9.2 million in 2025-2027 respectively.

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Request IR-92:

Please list all capital items included in the application which have not yet received NSEB work order approval.

(a) Identify the included amounts for each project along with the associated amount for ROE and the associated depreciation amounts.

(b) Identify when each project will be submitted for Board approval.

Response IR-92:

The capital budget amounts included in the GRA reflect assumptions at a point in time and are not all project specific. Since the capital budget amounts included in the GRA were completed, the 2024 ACE Plan has been filed and includes project-specific forecasts for 2024 and updated assumptions for 2025 and 2026. Additionally, the 2025 ACE Plan will be filed before the end of 2025 with detailed projects lists for 2026 and updated assumptions for 2027.

Please refer to Attachment 1 for the capital items with investment in the test period, not yet approved by the NSEB that have specific capital project budgets that were used for the purpose of the GRA. The year listed for expected filing is the current expectation and may not be aligned with the estimate included in the GRA as reforecasting activities and prioritization exercises have occurred since the development of the GRA capital forecast.

NS Power's capital forecast is completed at a portfolio level based upon the anticipated capital investment requirements at the time of GRA forecast development. Certain investments that are included in the test period may not advance during the test period and other projects are likely to differ in the timing of investment as NS Power utilizes its asset management framework to refine the capital plan. While certain investments included in the GRA may not advance, or will advance

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1 on a differing timeline, NS Power expects that other capital investments will take their place and
2 the overall level of expected capital investment will be similar to that which is included in forecast.

3
4 NS Power calculates depreciation expense at an asset group level and not at a project level, except
5 for in certain circumstances such as unapproved capital investment. NS Power has not calculated
6 the depreciation associated with the projects in Attachment 1. Assuming there was no depreciation
7 expense associated with these projects over the test period, the equity portion of financing expense
8 associated with these projects is approximately \$7 million in 2026 and \$14 million in 2027.

2026-2027 GRA NSEB IR-92 Attachment 1 has been filed electronically.

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Request IR-93:

Please list all capital items included in the rate base which have not received Final Cost approval from the NSEB.

(a) Include the approved work order total, the final cost (if concluded), and the amount included in rate base along with the date it was included.

(b) For each of the above, list the individual depreciation amounts and ROE amounts included in the application.

Response IR-93:

(a-b) Per the Capital Expenditure Justification Criteria, Final Cost approval is required when an individual capital item has realized a scope change or has final costs with a variance of more than the greater of +/-5 percent or +/- \$250,000. The capital budgets used for the purposes of the GRA were not all project specific. Where specific capital project budgets were used for the purpose of the GRA, these projects are not yet complete. As such, NS Power is unable to determine if any of these projects may require Final Cost approval from the NSEB in the future.

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

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Request IR-94:

With respect to rate base and regulated capitalization, please reconcile the two balances as of the December 31, 2023, and December 31, 2024, year ends.

Response IR-94:

Please see below:

Rate Base (\$ million)	2023	Part VI.1 Tax Adjustment (M12248)	2023 Corrected
Net Utility Fixed Assets	4,719.9		4,719.9
Deferred Charges & Credits	404.9		404.9
Long term receivable	82.2		82.2
Allowance for materials and supplies	345.2		345.2
Allowance for working capital	123.8	(8.2)	115.6
Total Rate Base	5,676.0	(8.2)	5,667.8
Regulated Capitalization	5,667.8	(8.2)	5,659.6

Rate Base (\$ million)	2024	Part VI.1 Adjustment (M12248)	2024 Corrected
Net Utility Fixed Assets	4,908.2		4,908.2
Total Deferred Charges & Credits	16.9		16.9
Long term receivable	87.4		87.4
Allowance for materials and supplies	306.3		306.3
Allowance for working capital	72.2	(8.6)	63.6

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

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Rate Base (\$ million)	2024	Part VI.1 Adjustment (M12248)	2024 Corrected
Total Rate Base	5,391.0	(8.6)	5,382.4
Regulated Capitalization	5,391.0	(8.6)	5,382.4

1

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Request IR-95:

On page 93 of the Board Decision [2022 NSUARB 18] in M10206 (NSPML) dated February 9, 2022, the Board advised that it would not permit recovery by NS Power of operating costs of Lingan 2 beyond August 15, 2022, without further order of the Board. In its decision letter approving the LIN2 2023/2024 Winter Capacity project (M11706), the Board approved a request for the inclusion of operating expenses for LIN2 from 2022 to and including Q4 2024 as regulated operating expenditures for the year 2024. However, this approval only applied for operating expenses until the end of 2024. The Board directed that NS Power would be required to seek Board approval of any LIN2 operating expenses beyond that date. In its decision letter dated August 28, 2025, approving the LIN2 2024/2025 Winter Capacity project (M12316), the Board noted NS Power's response to IR-8 that it had operating expenses of \$381,698 in Q1 2025, and that it intended to request Board approval of these costs in a future proceeding. Please confirm whether these costs and other operating costs for LIN2 in 2025 and the two test years are being claimed in this application.

(a) If confirmed, please identify the related costs.

Response IR-95:

Confirmed; the operating costs for Lingan Unit 2 in 2025, 2026 and 2027 are forecast in this application. The operating costs for Lingan Generation station are not forecast to the specific unit level. The 2025 10-Year System Outlook specifies that Lingan Unit 2 is needed to support capacity during the GRA period, so its operating costs should be recovered. Since the February 9, 2022 decision, Lingan Unit 2's mission has shifted, making timely recovery of these costs more appropriate. Actual operating costs for these years will be submitted for Board approval, similar to M12316, with adjustments as needed during the proceeding.

REDACTED

Request IR-96:

Reference: Exhibit N-3 GRA Direct Evidence, 9.3 Maritime Link Capital Applications

On page 60, NS Power addresses the Board's directive from the 2023-2024 GRA Decision regarding inclusion of four Maritime Link transmission projects into rate base. That directive required demonstration that a combination of the wheeling tariff revenue and the economic value of purchased Nalcor surplus energy is at least equal to the combination of depreciation, financing costs, operating costs, and re-dispatch costs over a minimum of four consecutive quarters. Figure 9-5 on page 60 lists the total benefits and total costs of Maritime Link utilization for Q2 2024, Q3 2024, Q4 2024 and Q1 2025.

(a) Please provide a breakdown of those total benefits and total costs by each of the categories noted above for each quarter.

(b) Please state the amount of Nalcor surplus energy purchased in each of the quarters and explain how the dollar amount of benefit was determined.

(c) Please provide an estimated cost for those same quantities of energy based on the cost of generation which does not include Maritime Link energy.

(d) Please state the capital costs for each of those four transmission projects and the forecast net book values that have been included in rate base at the beginning of the 2026-2027 test period.

Response IR-96:

(a-c) Please refer to the table below.

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

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	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Surplus and Bilateral Energy (MW)				
Surplus and Bilateral Benefit (CAD) ⁽¹⁾				
Purchase Cost of Surplus and Bilateral (CAD) ⁽¹⁾				
Estimated Cost of same quantity from non-Maritime Link Energy (CAD) ⁽¹⁾				
Wheel through Energy (MW)				
Transmission Revenue (CAD)				
Depreciation cost (CAD)	\$333,949	\$333,949	\$333,949	\$333,949
Financing costs (CAD)	\$620,819	\$615,208	\$609,598	\$603,988

⁽¹⁾ Amounts have been translated into CAD and rounded to millions may cause rounding differences on some line items.

At no point were NS Power's tie-lines constrained; therefore, there was no incremental cost of redispatch to allow flow through.

- (d) Please refer to GRA Application, Appendix 9A, 9B, 9C, and 9D for original capital costs. Please refer to the table below for Remaining Net Book Values as of January 1, 2026 included in the GRA.

CI #	Project Name	Remaining NBV Jan. 1, 2026
45066-T802	Upgrade L6511 and L7019 (T802)	\$2,071,215
43678-T800	Separate L8004/L7005 (T800)	\$16,686,562
45067-T801	67N Onslow 345 KV Node Swap (T801)	\$2,472,071
43324-T782	L6513 Rebuild/upgrade line terminal (T782)	\$13,553,047
	Total	\$34,782,895

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Request IR-97:

Reference: Exhibit N-3, GRA Direct Evidence

On page 61 of the application, NS Power states that since the Maritime Link transmission projects have met the Board's threshold test, the transmission assets are forecast in the test years at their forecast net book value.

(a) Please provide a continuity schedule from the time of commissioning of the projects, showing the opening rate base amount to be included in the GRA forecast starting January 1, 2026.

Response IR-97:

(a) Please see the table below:

Capital Item #	Project Name	Project Cost	Depreciation Incurred at Shareholder Expense	Net book value at Jan 1, 2026
45066	Upgrade L6511 and L7019 Thermal Rating	2,546,158	474,943	2,071,215
43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower	20,383,876	3,697,314	16,686,562
45067	67N Onslow 345 KV Node Swap	2,982,713	510,642	2,472,071
43324	L6513 Rebuild/Upgrade line terminal	18,625,082	5,072,035	13,553,047
	Total	44,537,829	9,754,934	34,782,895

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1 **Request IR-98:**

2
3 **Reference: Exhibit N-17, SR-04, Attachment 1, Figure 1**

4
5 **(a) Please confirm, or explain otherwise, that NS Power's working capital requirement**
6 **is approximately 7% of its net-cash expenses in 2023 and proposed to be 8.4% in 2026**
7 **and 6.9% in 2027.**

8
9 **(b) What is causing the significant increase in working capital requirement in 2026?**

10
11 **(c) Please compare NS Power's working capital requirement to the peer group used in**
12 **ScottMadden's Benchmarking Analysis Report (OP-03, Attachment 1).**

13
14 **Response IR-98:**

15
16 **(a) Confirmed.**

17
18 **(b) The increase is driven by the investment tax credit the Company is expected to receive.**
19 **The investment tax credit has been included as a tax offset for 2026. However, it is expected**
20 **to be received by the Company at the end of 2027, which is driving the higher cash working**
21 **capital requirement in 2026.**

22
23 **(c) The Benchmarking Analysis Report in OP-03 Attachment 1 did not include a comparison**
24 **of working capital requirement.**

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1 **Request IR-99:**

2
3 **Reference: Exhibit N-17, SR-04 Attachment 1, Lead-Lag Study**

4
5 **On pg. 19 of the lead-lag study it is noted that the significant increase in working capital**
6 **related to taxes is due to customers receiving the benefit of an Investment Tax Credit related**
7 **to a clean energy storage project prior to the company's receipt of the ITC.**

8
9 **(a) Please confirm, or clarify otherwise, that NS Power will need to pay tax installments**
10 **during 2026 that it then expects to be refunded in 2027 due to the ITC.**

11
12 **(b) If not confirmed, why does this require an increase in working capital?**

13
14 **Response IR-99:**

15
16 **(a) NS Power will be required to make installment payments in 2026 in respect of Part VI.1**
17 **tax related to NS Power's preferred share dividends. These installment payments will not**
18 **be refunded as they are not related to the ITC.**

19
20 **(b) Nova Scotia Power forecasts to recognize the increased income tax recovery associated**
21 **with the ITC in 2026, therefore decreasing revenue requirement and expected revenue from**
22 **customers. However, NS Power does not expect to receive the cash associated with this**
23 **ITC until the end of 2027, at the earliest. As a result, NS Power reflects earnings without**
24 **the corresponding cash receipt and must finance this through working capital. In effect,**
25 **this is an expected increase in income tax accounts receivable.**

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Request IR-100:

Section 30(5)(b) of the *Public Utilities Act* directs the Board to set different levels of return on equity for different classes of capital assets of NS Power to ensure that investment incentives are aligned with ratepayer objectives as submitted to the Board in a hearing for a rate change. Please detail how NS Power has addressed this statutory requirement in its application.

Response IR-100:

Section 30(5)(b) of the *Public Utilities Act* expressly permits and requires the Board to act, when customer representatives submit objectives that would require a distinction to be drawn between classes of capital assets in order to ensure that investment incentives are aligned. This section is inapplicable to this GRA, as no such objectives that would require a distinction to be drawn have been submitted to the Board and as all customer representatives are supportive of the continuation of NS Power's current capital structure and cost of financing.

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1 **Request IR-101:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 10 Capital Structure and Financing**

4
5 **With respect to the rate of return earned:**

6
7 **(a) Please identify the actual rate of return that has been earned in each of the past 10**
8 **years, starting in 2015 (corrected for removal of Part VI.1 tax transactions from 2022**
9 **onward, if applicable).**

10
11 **(b) Please state the allowed range of ROE for each of the past 10 years.**

12
13 **(c) Please identify all years where the rate of return earned has been less than the**
14 **minimum allowed.**

15
16 **(d) How many of those years in which the rate of return was achieved, were funded, at**
17 **least partially, with the assistance of reduced tax expense from amended tax filings?**

18
19 **Response IR-101:**

20
21 **(a–c)** Please see the table below. Please note that in certain years NS Power’s equity thickness
22 was below 40 percent as it did not have sufficient earnings to maintain its approved
23 regulated equity percentage. The table indicates the years in which this occurred and notes
24 that the ROE that would have been achieved at 40 percent equity.

25
26 The ROE figures below do not contemplate unregulated costs that are paid for by
27 shareholders. The inclusion of these costs would generally result in a further reduction in
28 the ROE of approximately 50 basis points.

2026-2027 General Rate Application (M12451)
NSPI Responses to NSEB Information Requests

NON-CONFIDENTIAL

Year	Actual ROE	Allowed ROE Range	ROE Below Minimum?	Equity Below 40%	ROE at 40% Equity
2015	9.25	8.75 - 9.25	No	No	N/A
2016	9.25	8.75 - 9.25	No	No	N/A
2017	9.25	8.75 - 9.25	No	No	N/A
2018	9.25	8.75 - 9.25	No	No	N/A
2019	9.25	8.75 - 9.25	No	No	N/A
2020	7.88	8.75 - 9.25	Yes	No ¹	N/A
2021	9.08	8.75 - 9.25	No	Yes	8.80
2022	8.65	8.75 - 9.25	Yes	Yes	8.31
2023	8.28	8.75 - 9.25	Yes	Yes	7.70
2024	8.74	8.75 - 9.25	Yes	Yes	8.29

(d) The amended corporate income tax returns filed in the years in which the rate of return was achieved are as follows:

Scientific Research & Experimental Development Investment Tax Credits

NS Power routinely amends its corporate income tax returns to claim Scientific Research & Experimental Development (“SR&ED”) Investment Tax Credits (“ITC’s”). The reduced income tax expense related to the SRED ITC’s during the years that the rate of return was achieved are as follows:

2015 – nil

2016 – \$0.2 million

2017 – \$0.1 million

2018 – \$0.2 million

2019 – nil

2021 – nil

¹ Actual was 39.9%, which is being treated here as 40%.

NON-CONFIDENTIAL

1 Accrued Refund Interest Error Correction

2 During 2018, the Canada Revenue Agency (“CRA”) accepted NS Power’s request to
3 amend the 2011, 2012 and 2013 corporate income tax returns to remove approximately
4 \$3.8 million of accrued refund interest that was incorrectly reported as taxable income in
5 those years. The reduced income tax expense related to these amendments during the years
6 in which the rate of return was achieved was approximately \$1.2 million.

7
8 Biomass Generation Asset Cost Reallocation

9 During 2018, the CRA accepted NS Power’s request to amend the 2012 and 2013 corporate
10 income tax returns to reallocate certain biomass generation asset costs between Schedule 8
11 and Schedule 10 of the corporate income tax return. The amendments resulted in a
12 reduction in taxable income of approximately \$0.4 million across those years and would
13 have had an insignificant impact on tax expense during the years in which the rate of return
14 was achieved.

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1 **Request IR-102:**

2
3 **Please provide the most recent credit rating reports for NS Power from S&P and DBRS**
4 **Morningstar.**

5
6 Response IR-102:

7
8 Please refer to Attachment 1 for DBRS Morningstar ratings reports and Attachment 2 for S&P.

Rating Report

Nova Scotia Power Inc.

Morningstar DBRS

January 15, 2025

Commercial Paper Limit

\$800 million

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Credit Ratings

Obligation	Rating	Rating Action	Trend
Issuer Rating	BBB (high)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	BBB (high)	Confirmed	Stable
Commercial Paper	R-2 (high)	Confirmed	Stable

Credit Ratings Drivers

Positive Credit Rating Drivers	Negative Credit Rating Drivers
A positive credit rating action could occur if (1) the regulatory process for the next GRA conducted free of any interference and with the NSUARB's full independence on the determination of rates, (2) establishment of the NSIESO which will reduce NSPI's exposure to penalties under the RER, and (3) key credit metrics in line with the "A" credit rating category.	A negative credit rating action could occur if there is further political interference in the regulatory process for NSPI, or if key credit metrics weaken to a level no longer supportive of the current ratings (i.e., cash flow-to-debt remaining below 10% for a sustained period).

Key Credit Rating Considerations

The ratings of Nova Scotia Power Inc. (NSPI or the Company) are based on its integrated electricity operations under the Nova Scotia Utility and Review Board (NSUARB). The Stable trends reflect the Company's key credit metrics which are in line with the BBB rating category.

There were several positive developments for NSPI in 2024. In April, the NSUARB approved for the sale of \$117 million of fuel-adjustment mechanism (FAM) regulatory assets from NSPI to the Province of Nova Scotia (the Province; rated A (high) with a Stable trend). NSPI will collect this amount from customers on behalf of the Province over a 10-year period. In September 2024, the federal government also finalized an agreement with NSPI, NSP Maritime Link Inc. (NSPML; Maritime Link Financing Trust rated (P) AAA with a Stable trend), and the Province for a federal loan guarantee of \$500 million of debt to be issued by NSPML. Proceeds from this December 2024 issuance were transferred to the Company and applied against the FAM regulatory asset balance. NSPI will collect this amount from customers on behalf of NSPML over a 28-year period. These two transactions (1) will reduce debt at the Company by \$617 million, (2) reduce regulatory lag for NSPI disposing of the balance in the FAM, and (3) reduce rate pressure on customers as the recovery is spread over a much longer period.

Furthermore, in April 2024, the Province enacted *Bill 404 - Energy Reform (2024) Act*. Bill 404 enacts the *More Access to Energy Act*, which provides for the establishment and transition to the Nova Scotia Independent Energy System Operator (NSIESO). The NSIESO will be tasked with operating the Provincial electricity grid as well as energy forecasting and resource planning. This will streamline NSPI's responsibilities so it can focus on its operations as an integrated utility. Importantly, while the Company

will still be required to adhere to climate change regulations and, as the dominant utility in the Province, be involved in the transition, the responsibility for procuring renewable energy in the Province and meeting targets under the Renewable Electricity Regulations (RER) are expected to be transferred to the NSIESO.

While these developments will strengthen NSPI's financial metrics and reduce uncertainty under the RER, we remain concerned about potential political interference in the next regulatory review process. We note that during the recent November Provincial election, the Progressive Conservative's (PC) platform included a proposal to cap electricity rate increases at the average increase across the country. Should legislation be enacted by the Province that, once again, diminishes the NSUARB's independence and impacts the Company's ability to fully recover its costs in its next General Rate Application (GRA), a negative rating action would likely occur.

Earnings Outlook

Earnings for NSPI have generally been very stable, reflecting the regulated nature of its operations. The Company has a FAM in place that allows it to recover actual fuel costs from customers through annual rate adjustments. Earnings increased in 2023 because of a base-rate increase of 1.8% effective February 2023; however, NSPI achieved a return on equity (ROE) of 8.25%, which was below the approved regulated ROE band of 8.75% to 9.25%. We do not expect the Company's financial performance to materially improve until the next GRA and rates are rebased, which we expect to occur in 2026.

Financial Outlook

NSPI's key credit metrics strengthened in the last 12 months ended September 30, 2024 (LTM 2024), because of the stronger earnings and cash flows, and the reduction in debt following the sale of the \$117 million balance in the FAM to the Province. We expect the Company's metrics to further strengthen in 2024 following the \$500 million transfer from NSPML, proceeds of which were used to pay down debt. NSPI has a significant capital expenditures (capex) program, however (around \$630 million annually for the next three years), as the Company invests in reliability of the network and growth in the customer base. We expect NSPI to be prudent in financing its capex and dividends to maintain key credit metrics in line with the BBB credit rating range. NSPI's parent company, Emera Inc. (Emera), has historically been supportive of the Company by maintaining a flexible dividend payout policy (none paid in 2023 and 2024) and providing equity injections (\$308 million received in 2023) to maintain leverage in line with the regulatory capital structure.

Financial Information

	12 mos. ended Sep. 30		For the year ended December 31			
	2024	2023	2022	2021	2020	2019
Cash flow/total debt (%)	10.7	9.9	9.8	12.9	12.6	14.4
Total debt in capital structure (%) ¹	64.5	66.3	69.9	66.3	66.6	62.4
EBIT gross interest coverage (x)	1.32	1.39	1.58	1.97	2.02	2.00

¹ Adjusted for accumulated other comprehensive income.

Issuer Description

NSPI is a fully integrated, regulated utility that generates, transmits, and distributes electricity in Nova Scotia. The Company is wholly owned by Emera, which is a diversified energy and energy-services holding company.

Business Risk Assessment*1. Low-risk regulated electricity business*

The Company's current regulatory framework is based on a cost-of-service (COS) methodology, under which NSPI can recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments. We view NSPI's target ROE range of 8.75% to 9.25% as reasonable and in line with the Company's Canadian peers. NSPI is also allowed to use a FAM, which mitigates the risk associated with fluctuating fuel prices. Under the FAM, the difference between actual fuel costs and amounts recovered from customers (through fuel rates) are deferred and collected from or refunded to customers in subsequent years. We note, however, the recent intervention by the Province in the GRA process has heightened regulatory risk and introduced volatility and instability for the Company.

2. Political intervention in the ratemaking process

In November 2022, the Province passed Bill 212, which amended the Public Utilities Act to cap the base-rate increase for NSPI's most recent GRA at 1.8% during the 2022 to 2024 period, excluding demand side management (DSM) and fuel and purchased power costs, and to limit the allowed ROE and deemed equity to 9.25% and 40.0%, respectively. We consider any political interference in the ratemaking process as credit negative because it introduces instability and unpredictability in the regulatory framework, and it impairs the independence of the regulator in determining the appropriate ROE and deemed equity ratio.

3. Unfavourable generation mix

As a result of the current generation mix, NSPI is dependent on international suppliers for its fuel supply, exposing the Company to volatile global pricing. This exposure, combined with continued investment in renewable energy, contributed to higher-than-average electricity retail rates compared to other Canadian provinces. Higher electricity rates could make it increasingly challenging for NSPI to fully pass on costs to ratepayers in a timely manner. Energy delivery from the Muskrat Falls Hydroelectric Project, which began in 2021, will reduce the contribution of coal-based assets; however, these assets are still expected to constitute a part of the generation mix until 2030. The Canada-Nova Scotia Equivalency Agreement (the Equivalency Agreement) should allow NSPI to remain compliant with federal emission regulations through 2029; however, federal and provincial regulations mandate the closure of all coal-based power plants by 2030, and significant investments will be needed to replace coal-generating capacity.

4. Good franchise strength

NSPI is the primary electricity supplier for the Province, providing more than 95% of its electricity generation, transmission, and distribution. Although the *Electricity Reform (2013) Act* permits licensed retail suppliers to sell renewable electricity generated within the Province directly to retail customers

under established tariffs (renewable-to-retail tariffs), we do not expect a material attrition rate to weaken NSPI's franchise strength significantly. As at September 30, 2024, no retail suppliers were operating under these renewable-to-retail tariffs.

5. Regulatory lag

NSPI faces some regulatory risk with respect to the timeliness of fuel cost recovery, although this risk is lower now than when the FAM was not in place. Although the FAM allows the Company to recover fluctuating fuel expenses from its customers, the rate adjustments are annual and subject to the NSUARB's approval. We expect the impact of fluctuating fuel prices to lessen going forward with energy delivery from the Muskrat Falls Hydroelectric Project, which increased the contribution of renewable energy supply to the Company's overall generation mix.

Financial Risk Assessment

1. Reasonable financial profile

NSPI's key credit metrics are reasonable for the current rating category. For the LTM 2024, the Company's cash flow-to-debt ratio was in line with the BBB rating category, while the stronger debt-to-capital ratio offset a weaker EBIT-to-interest coverage.

2. Limited access to equity markets

NSPI has limited access to common equity markets to fund any free cash flow deficits. As such, we expect Emera to continue to support the Company's capex program with a flexible dividends policy and equity injections, if needed.

Environmental, Social, and Governance Checklist

ESG Factor	ESG Credit Consideration Applicable to the Credit Analysis: Y/N	Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*	
Environmental		Overall:	Y R
Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuer's financial, operational, and/or reputational standing?	N	N
Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long-term credit profile?	Y	R
Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N
Land Impact and Biodiversity	Is there a financial risk to the issuer due to the loss of biodiversity and/or the mitigation of such loss, including land conversion and rehabilitation?	N	N
Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact?	N	N
	In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by physical and/or transition risks under key IPCC climate scenarios?	N	N
	Climate and Weather Risks:	N	N
Passed-through Environmental credit considerations	Does this rating depend to a large extent on the creditworthiness of another rated issuer which is impacted by environmental factors (see respective ESG checklist for such issuer)?	N	N
Social		Overall:	N N
Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services pose a financial or regulatory risk to the issuer?	N	N
	Do changes in consumer behaviour or secular social trends pose a financial or regulatory risk to the issuer?	N	N
	Social Impact of Products and Services:	N	N
Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts, that could result in a material financial or operational impact?	N	N
	Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	N	N
	Human Capital and Human Rights:	N	N
Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N
Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N
Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N
Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N
Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Passed-through Social credit considerations	Does this rating depend to a large extent on the creditworthiness of another rated issuer which is impacted by social factors (see respective ESG checklist for such issuer)?	N	N
Governance		Overall:	N N
Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
	Are there any political risks that could affect the issuer's financial position or its reputation?	N	N
	Bribery, Corruption, and Political Risks:	N	N
Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N
	Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
	Does the board and/or management lack a formal framework to assess climate related financial risks to the issuer?	N	N
	Corporate / Transaction Governance:	N	N
Passed-through Governance credit considerations	Does this rating depend to a large extent on the creditworthiness of another rated issuer which is impacted by governance factors (see respective ESG checklist for such issuer)?	N	N
Consolidated ESG Criteria Output:		Y	R

ESG Considerations**Environmental**

Carbon and greenhouse gas (GHG) costs had a relevant effect on the credit analysis of NSPI. We consider the Company's transition from reliance on coal-based generation (51% of 2023 installed generation capacity) to lower-emitting sources to be a challenge, as coal-fired generation is mandated to be phased out, and 80% of electricity sales are to be from renewable sources by 2030. We note that once the NSIESO is established, the responsibility of procuring renewable energy in the Province will transition away from NSPI. However, we expect significant investments will still be needed by the Company, including substantial funding support from both the Provincial and Federal governments.

Social

There were no social factors that had a relevant or significant effect on the credit analysis. As a regulated utility, NSPI provides an essential service to its customers. Any disruptions in its operations could result in reputation damage as well as financial penalties. As of Q3 2024, the Company had 1.48 outages per customer and 3.99 hours of outages per customer, both of which were below the 2024 target of 2.05 outages and 4.29 hours, respectively. NSPI is also committed to the safety of its employees and customers.

Governance

There were no governance factors that had a relevant or significant effect on the credit analysis. NSPI's board of directors includes nine members, seven of whom are independent directors. The board has oversight over climate-related issues at the Company.

A description of how Morningstar DBRS considers ESG factors within the Morningstar DBRS analytical framework can be found in *Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Factors in Credit Ratings* at <https://dbrs.morningstar.com/research/437781>.

Rating History

	Current	2023	2022	2021	2020	2019
Issuer Rating	BBB (high)	BBB (high)	BBB (high)	A (low)	A (low)	A (low)
Unsecured Debentures & Medium-Term Notes	BBB (high)	BBB (high)	BBB (high)	A (low)	A (low)	A (low)
Commercial Paper	R-2 (high)	R-2 (high)	R-2 (high)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Action

- "DBRS Morningstar Confirms Credit Ratings on Nova Scotia Power Inc. at BBB (high) and R-2 (high), Stable Trends," December 20, 2023.

Previous Report

- Nova Scotia Power Inc.: Rating Report, January 12, 2024.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on [dbrs.morningstar.com](https://www.dbrs.morningstar.com).

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Appendix 1 — Liquidity and Debt Profile

Liquidity

(CAD millions as at September 30, 2024)	Amount	Drawn/Letter of Credit	Available	Expiry
Cash & cash equivalents	3	-	3	N/A
Committed revolving facilities	800	291	509	June 2029
Total	803	291	512	

- We consider the Company's liquidity position to be adequate with sufficient headroom under its committed revolving credit facility to support operating requirements.
- NSPI has an \$800 million credit facility maturing in December 2029.
 - The credit facility is used to backstop the Company's \$800 million commercial paper (CP) program and to partially fund its working capital and capex requirements. Availability under the credit facility is reduced by the amount of CP issued. The credit facility is also subject to a financial covenant (debt-to-capital ratio of less than or equal to 70.0%), and NSPI is in compliance with the covenant as at September 30, 2024.

Long-term Debt

(CAD millions as at September 30, 2024)	2024	2025	2026	2027	2028	Thereafter	Total
Total long-term debt	0	425	40	0	0	3,268	3,733
%	0	11	1	0	0	88	100

- NSPI's long-term debt maturities are well spread out with minimum refinancing risk in the near term.
- The Company has a debenture covenant, which states that NSPI would not incur debt if its funded debt would be more than 75% of total capitalization. The debenture covenant is not expected to restrict the Company's operations going forward or pose any challenges in the near to medium term.

Appendix 2—Regulation

- NSPI operates under the NSUARB's regulatory environment using a COS methodology that allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments.
- NSPI's target ROE range, approved by the NSUARB, is between 8.75% and 9.25% based on an actual five-quarter average-regulated common equity component of up to 40.00%.
 - The Company historically achieved actual ROE in the higher end of the target range.
- NSPI is not subject to an annual rate review process; rather, the Company participates in a general rate-setting process from time to time at its discretion or at the NSUARB's request.
- In November 2022, the Province amended the Public Utilities Act through Bill 212 to cap base-rate increases for NSPI at 1.8% during the 2022 to 2024 period and limit the ROE and deemed equity to, respectively, 9.25% and 40.0%. Bill 212 also requires that the base-rate increase can be used only for the improvement of reliability of services to customers.
 - We consider this political intervention to be negative to the regulatory assessment of NSPI as it interferes with the stability and predictability of the ratemaking process as well as the independence of the NSUARB in determining the appropriate ROE and deemed equity for the Company.
- In February 2023, the NSUARB approved most of a negotiated settlement filed by NSPI and intervenors for the Company's GRA for rates effective 2022 to 2024. Under the negotiated settlement, the NSUARB approved the following:
 - An average rate increase of 6.9% for each 2023 and 2024 composing of a base-rate increase of 1.8%, a DSM increase of 3.6% and a fuel increase of 1.5% for 2023, and a DSM increase of 0.3% and a fuel increase of 6.6% in 2024;
 - ROE unchanged at 9.0% based on an earnings band of 8.75% to 9.25%;
 - Maximum allowed equity unchanged at 40%;
 - A decarbonization deferral account to recover undepreciated thermal asset value and unrecovered decommissioning costs; and
 - Storm rider for NSPI to have the option to apply for the recovery of major storm restoration expenses exceeding \$10.2 million, \$10.4 million, and \$10.4 million for 2023, 2024, and 2025, respectively.
- In December 2024, the NSUARB approved a Storm Rider of \$24 million to be recovered in 2025.
- NSPI also files an annual capex (ACE) plan with the NSUARB, which outlines its capital outlay for the forecast period. All spending for capital assets more than \$1,000,000 is subject to the NSUARB's approval.
 - In August 2024, the NSUARB approved the 2024 ACE plan of \$151.9 million.
- NSPI has a FAM in place that, subject to the NSUARB's review and approval, allows the Company to recover fluctuating fuel expenses through annual rate adjustments.
 - In April 2024, NSPI sold \$117 million of the FAM regulatory asset to the Province. The Company will collect this amount from customers on behalf of the Province over a 10-year period.

- In December 2024, NSPML issued \$500 million of debt, guaranteed by the federal government, the proceeds of which were transferred to NSPI to reduce the balance under its FAM regulatory account. The Company will collect this amount on behalf of NSPML over a 28-year period.

Environmental Regulation

- In October 2017, the Province passed amendments to the Environment Act for the development of a cap-and-trade program for carbon emissions, which became effective on January 1, 2019.
 - In July 2021, the Province amended the RER to mandate that 80% of electricity sales should be from renewable sources by 2030.
 - In November 2021, the Province passed the Environmental Goals and Climate Change Reduction Act, which mandated the phasing out of coal-fired generation by 2030.
- In November 2014, the Province and the Government of Canada (rated AAA with a Stable trend) entered into an Equivalency Agreement regarding GHG from electricity producers in the Province. The Equivalency Agreement allows NSPI to achieve compliance with federal GHG emission regulations by complying with provincial regulatory requirements, which are deemed equivalent. The Equivalency Agreement came into force on July 1, 2015, and was terminated on December 31, 2019.
 - In December 2018, the Government of Canada published new federal GHG regulations for coal-fired electricity plants. Under the regulations, power plants that emit more than 420 tonnes of carbon dioxide emission from fossil fuels for each gigawatt hour (GWh) of electricity generated will have to be closed by (1) the earlier of (A) December 31 of the calendar year 50 years after the commissioning date and (B) December 31, 2019, if commissioned before 1975; or (2) the earlier of (A) December 31 of the calendar year 50 years after the commissioning date and (B) December 31, 2029, if commissioned after 1974.
 - In December 2019, the Province and the Government of Canada renewed the Equivalency Agreement, which will allow NSPI to achieve compliance with the federal GHG regulation until 2029 by complying with provincial regulations. The renewed Equivalency Agreement came into force on January 1, 2020, and was renewed in August 2024 until December 31, 2029.
 - As a result of the COVID-19 pandemic, there was a delay to the in-service date for the Muskrat Falls Project, delaying the delivery of power to NSPI; the Company would thus be unable to achieve the provincially legislated target of 40% of electric sales generated from renewable sources in 2020.
 - In May 2020, the Province provided an alternative compliance plan, where NSPI would have to meet the 40% target over a three-year period of 2020 to 2022.
- In April 2023, the Province levied a \$10 million penalty on NSPI for noncompliance with the RER in 2022.
 - The Company has filed an application with the NSUARB appealing the penalty.
- In October 2023, the Province published its 2030 Clean Power Plan.

- Under the plan, the Province intends to add new wind, solar, and natural gas generation capacity, as well as deploy battery storage and for the construction of a new transmission line to New Brunswick to improve reliability.
- In April 2024, the Province enacted *Bill 404 - Energy Reform (2024) Act*.
 - Bill 404 enacts the *More Access to Energy Act*, which provides for the establishment and transition to the NSIESO, which will be tasked with operating the Provincial electricity grid as well as energy forecasting and resource planning.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory Below Average Poor	NSPI's target-regulated ROE is based on an actual five-quarter average-regulated common equity component of up to 40.0%. We note that under Bill 212, the Company's deemed equity is capped at 40.0% for 2022 to 2024.
2. Allowed ROE	Excellent Good Satisfactory Below Average Poor	NSPI's target regulated ROE range is between 8.75% and 9.25%. Actual regulated ROE had historically been in the higher end of this target range but will likely be at the bottom of the range for 2022 to 2024. We note that under Bill 212, the Company's ROE is capped at 9.25% for 2022 to 2024.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	Fuel costs are passed to customers through the FAM, and rates change annually to account for variances between forecast and actual fuel costs. Fuel costs are subject to an independent audit by the NSUARB that could potentially disallow a portion of fuel-related costs.
4. Capital and Operating Cost Recovery	Excellent Good Satisfactory Below Average Poor	Capital costs of more than \$1,000,000 are generally preapproved by the regulator, but there is some modest upfront capex before regulatory approval. NSPI earns an allowance for funds used during construction (AFUDC). Once the project is complete and put into service, the cost of the asset, including AFUDC, is recovered from customers through rates.
5. COS versus Incentive Rate Mechanism	Excellent Good Satisfactory Below Average Poor	NSPI is regulated under a COS model that allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments.
6. Political Interference	Excellent Good Satisfactory Below Average Poor	In November 2022, the Province passed Bill 212, which amended the Public Utilities Act and directly interfered with the ongoing GRA for NSPI's 2022 to 2024 rates. We consider this adverse intervention to be negative for the Company's regulatory environment as it injected volatility and heightens uncertainty with the regulatory process. We further note that in the most recent election campaign, the PC's platform included capping rate increases for NSPI at the country wide average.
7. Stranded Cost Recovery	Excellent Good Satisfactory Below Average Poor	The NSUARB disallowed the recovery of some, but not a material amount of, fuel-related costs.
8. Rate Freeze	Excellent Good Satisfactory Below Average Poor	The retail residential electricity rates in the Province are higher than the average among Canada's provinces. This could make it challenging for NSPI to pass all costs on to ratepayers in a timely manner. As part of Bill 212, the Province capped rate increases for the Company's 2022 to 2024 GRA at 1.8% for base rates, excluding DSM and fuel and purchase power costs.

About Morningstar DBRS

Morningstar DBRS is a full-service global credit ratings business with approximately 700 employees around the world. We're a market leader in Canada, and in multiple asset classes across the U.S. and Europe.

We rate more than 4,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

Morningstar DBRS is empowering investor success as the go-to source for independent credit ratings. And we are bringing transparency, responsiveness, and leading-edge technology to the industry.

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Tear Sheet:

Nova Scotia Power Inc.

January 28, 2025

What's new: Nova Scotia Power Inc. (NSPI) recently received a Canadian federal loan guarantee to securitize C\$500 million of current and future fuel balances at NSPI; the company used proceeds toward reducing debt at NSPI. This follows the C\$117 million NSPI received from the provincial government earlier in 2024 toward the deferred fuel cost recovery. S&P Global Ratings views these favorably because they reduced debt at NSPI while also reducing the regulatory lag associated with recovery of higher fuel costs in Nova Scotia, which in recent years pressured NSPI's credit measures. Furthermore, the government support also decreases the rate impact on customers by spreading out the recovery over a longer period (10 years for the provincial funding and 28 years for the federal loan).

Why it matters: In our view, securitization of the deferred fuel costs and debt reduction will improve NSPI's credit measures, with funds from operations (FFO) to debt estimated to average in the 10%-11% area over our forecast period. Combined with the recently approved multi-year rate case adjustment for Tampa Electric Co. and several initiatives executed by parent Emera Inc. (non-core asset sales, hybrid issuance), we believe these should allow Emera to improve its credit measures on a consolidated basis. Specifically, we project Emera to sustain FFO to debt comfortably above 10% in 2025 and 2026. Accordingly, on Jan 22, 2025, we revised the outlook on Emera and its subsidiaries, including NSPI, to stable from negative.

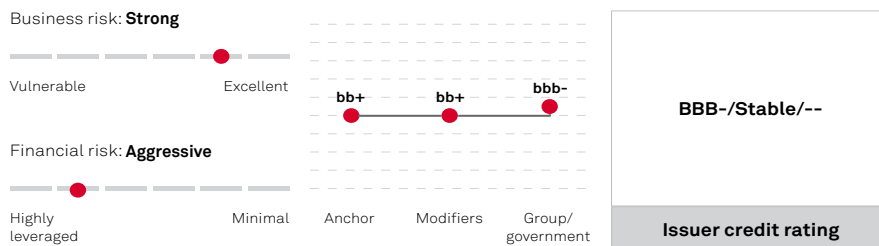
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Ratings Score Snapshot



Recent Research

- Research Update: Emera Inc. And Subsidiaries Outlook Revised To Stable From Negative On Improving Credit Strength, Ratings Affirmed, Jan 22, 2025
- Research Update: Emera Inc. And Subsidiaries Outlook Remains Negative On Weak Financial Performance; Ratings Affirmed, March 11, 2024
- Nova Scotia Power Inc., Feb. 12, 2024

Company Description

NSPI is a vertically integrated electric utility operating in Nova Scotia that contributes about 20% of its parent's consolidated net income. NSPI provides electricity generation, transmission, and distribution services to approximately 550,000 customers. NSPI owns generation capacity of about 2,420 megawatts, which it largely derives from coal (44% of total), natural gas (28%) and renewables (21%).

Outlook

The stable outlook on NSPI reflects the stable outlook of its parent Emera, as well as our expectation that NSPI's FFO to debt will average about 10%-11% through 2026. The improvement in credit measures from recent years is largely driven by the securitization of deferred fuel costs and corresponding debt reduction.

Downside scenario

We could lower our ratings on NSPI over the next 12-24 months if:

- Financial measures deteriorated, with FFO to debt consistently below 10%, or
- We lowered our rating on parent Emera.

Upside scenario

We could raise our rating on NSPI within our outlook period if:

- We raised our rating on Emera, or
- The company's business risk strengthened while FFO to debt remained above 10%.

Key Metrics

Nova Scotia Power Inc.--Forecast summary

Period ending	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026
(Mil. CAD)	2020a	2021a	2022a	2023a	2024e	2025f	2026f
Adjusted ratios							
Debt/EBITDA (x)	6.0	5.9	7.2	7.0	5.5-6.5	6.0-7.0	6.0-6.5
FFO/debt (%)	12.0	11.9	8.3	9.3	10.0-11.0	10.0-11.0	10.5-11.5
FFO cash interest coverage (x)	3.8	3.7	3.0	2.9	2.5-3.0	3.0-3.5	3.0-3.5

Nova Scotia Power Inc.

Financial Summary

Nova Scotia Power Inc.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	C\$	C\$	C\$	C\$	C\$	C\$
Revenues	1,440	1,430	1,494	1,501	1,675	1,671
EBITDA	550	513	529	535	509	557
Funds from operations (FFO)	408	381	380	378	305	363
Interest expense	155	154	150	145	150	183
Cash interest paid	135	136	137	139	149	194
Operating cash flow (OCF)	300	169	325	367	164	(121)
Capital expenditure	327	340	319	336	461	421
Free operating cash flow (FOCF)	(27)	(171)	6	31	(297)	(542)
Discretionary cash flow (DCF)	(204)	(171)	(252)	(49)	(447)	(542)
Cash and short-term investments	0	0	0	0	2	78
Gross available cash	0	0	0	0	2	78
Debt	2,821	2,855	3,170	3,173	3,660	3,906
Common equity	1,137	1,443	1,311	1,488	1,492	1,900
Adjusted ratios						
EBITDA margin (%)	38.2	35.9	35.4	35.6	30.4	33.3
Return on capital (%)	7.6	6.7	6.4	6.2	5.1	5.2
EBITDA interest coverage (x)	3.6	3.3	3.5	3.7	3.4	3.0
FFO cash interest coverage (x)	4.0	3.8	3.8	3.7	3.0	2.9
Debt/EBITDA (x)	5.1	5.6	6.0	5.9	7.2	7.0
FFO/debt (%)	14.5	13.4	12.0	11.9	8.3	9.3
OCF/debt (%)	10.6	5.9	10.3	11.6	4.5	(3.1)
FOCF/debt (%)	(0.9)	(6.0)	0.2	1.0	(8.1)	(13.9)
DCF/debt (%)	(7.2)	(6.0)	(7.9)	(1.5)	(12.2)	(13.9)

Peer Comparison

Nova Scotia Power Inc.--Peer Comparisons

	Nova Scotia Power Inc.	Tucson Electric Power Co.	Caribbean Utilities Co. Ltd.	Hawaiian Electric Co. Inc.
Foreign currency issuer credit rating	BBB-/Stable/--	A-/Negative/NR	BBB+/Negative/--	B-/Negative/B
Local currency issuer credit rating	BBB-/Stable/--	A-/Negative/NR	BBB+/Negative/--	B-/Negative/B
Period	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31
Mil.	C\$	C\$	C\$	C\$

Nova Scotia Power Inc.

Nova Scotia Power Inc.--Peer Comparisons

Revenue	1,671	2,477	379	4,318
EBITDA	557	811	107	799
Funds from operations (FFO)	363	686	83	637
Interest	183	130	26	123
Cash interest paid	194	124	24	113
Operating cash flow (OCF)	(121)	727	91	649
Capital expenditure	421	839	118	585
Free operating cash flow (FOCF)	(542)	(112)	(27)	64
Discretionary cash flow (DCF)	(542)	(197)	(60)	(108)
Cash and short-term investments	78	11	5	140
Gross available cash	78	11	5	140
Debt	3,906	3,368	524	2,676
Equity	1,900	3,763	429	3,204
EBITDA margin (%)	33.3	32.7	28.2	18.5
Return on capital (%)	5.2	7.6	6.2	7.5
EBITDA interest coverage (x)	3.0	6.2	4.2	6.5
FFO cash interest coverage (x)	2.9	6.5	4.4	6.6
Debt/EBITDA (x)	7.0	4.2	4.9	3.4
FFO/debt (%)	9.3	20.4	15.8	23.8
OCF/debt (%)	(3.1)	21.6	17.4	24.3
FOCF/debt (%)	(13.9)	(3.3)	(5.2)	2.4
DCF/debt (%)	(13.9)	(5.8)	(11.5)	(4.0)

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of Nova Scotia Power Inc., reflecting energy transition risks through its operations in electric generation that are primarily coal, natural gas, and oil. Relative to peers, greenhouse gas exposure to coal and fossil-fuel-emitting forms of generation is considerable and exposes the company to potentially more stringent environmental regulations in Canada. This exposure is somewhat mitigated by the company's position and growth strategy in renewable energy, particularly in hydro and wind.

Nova Scotia Power Inc.

Rating Component Scores

Foreign currency issuer credit rating	BBB-/Stable/--
Local currency issuer credit rating	BBB-/Stable/--
Business risk	Strong
Country risk	Very Low
Industry risk	Very Low
Competitive position	Satisfactory
Financial risk	Aggressive
Cash flow/leverage	Aggressive
Anchor	bb+
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	bb+
Group credit profile	bbb
Entity status within group	Strategically Important (+1 notch from SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Guarantee Criteria, Oct. 21, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

Nova Scotia Power Inc.

- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

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Request IR-103:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report

(a) Please confirm the dates and target overnight rates (i.e., policy rate) for each change in the policy rate announced by the Bank of Canada from January 1, 2022, to the present

(b) Since NS Power's last GRA in 2022, the Bank of Canada's overnight rate has come down and interest rates in Canada were restrained faster than in the US. Please discuss how this has been accounted for in Concentric's assessment of ROE.

Response IR-103:

(a) The table below provides the requested information:

Date of announcement of new rate	Target overnight rate
1/26/2022	0.25%
3/2/2022	0.50%
4/13/2022	1.00%
6/1/2022	1.50%
7/13/22	2.50%
9/7/2022	3.25%
10/26/2022	3.75%
12/7/2022	4.25%
1/25/2023	4.50%
6/7/2023	4.75%
7/12/2023	5.00%

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Date of announcement of new rate	Target overnight rate
6/5/2024	4.75%
7/24/2024	4.50%
9/4/2024	4.25%
10/23/2024	3.75%
12/11/2024	3.25%
1/29/2025	3.00%
3/13/2025	2.75%
9/17/2025	2.50%

1
2 (b) As explained in Concentric's report, interest rates are a direct input to the Capital Asset
3 Pricing Model and the Bond Yield Plus Risk Premium analyses. The Bank of Canada sets
4 the overnight rate, which is a short-term interest rate, based on its evaluation of
5 macroeconomic factors such as inflation, unemployment, and economic growth. In the
6 ROE analysis, however, the risk-free rate used in the CAPM and Risk Premium models is
7 a long-term interest rate. Concentric uses a forecast of 30-year government bonds in both
8 Canada and the U.S. The forecast bond yields in our report are lower than the current
9 interest rates on those securities, indicating that we have used conservative inputs for the
10 risk-free rate.

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1 **Request IR-104:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 33 of 87**

4
5 **Please explain how the risk profile of the TransCanada Mainline differs from the Canadian**
6 **electric utilities and the Canadian natural gas utilities included in the Canadian proxy group**
7 **and how the risk profile was determined.**

8
9 Response IR-104:

10
11 TC Energy is a natural gas pipeline and power/storage company that has a very different risk
12 profile than a regulated electric utility such as NS Power. In addition, the regulatory framework
13 for TC Energy is very different because the Canada Energy Regulator (formerly the National
14 Energy Board) has determined that competition affects the demand among shippers on the
15 TransCanada mainline and therefore the tolls TransCanada charges. TC Energy is currently
16 operating under the terms of a six-year negotiated settlement agreement with tolls fixed through
17 December 2026. In January 2025, TC Energy spun off its liquids pipeline segment (which
18 represented 17 percent of its total business) to shareholders and reduced its dividend by an equal
19 proportion. Forecast earnings growth rates for TC Energy were highly variable as of January 2025,
20 ranging from 12.5 percent from Value Line to negative from S&P Capital IQ. Concentric has
21 excluded TC Energy on a consistent basis from its Canadian proxy group for many years, including
22 in Concentric's January 2022 report in NS Power's previous GRA.

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1 **Request IR-105:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 34 of 87**

4
5 **Please explain how using maintaining cash dividends and growth projections from multiple**
6 **sources as selection criteria does not bias the proxy group results given the use of these**
7 **factors in estimation methods for return on equity.**

8
9 Response IR-105:

10
11 Both of these screens are related to the DCF model, which calculates the ROE by summing the
12 dividend yield and the expected growth rate. The DCF model assumes that companies consistently
13 pay quarterly cash dividends and that earnings, dividends and book value all grow at the same rate.
14 Therefore, it is necessary to exclude companies from the proxy group that have reduced or omitted
15 their dividend payment. Concentric applies this screen for a period of two years, as stated on page
16 30 of its report. The screen that requires a company to have positive earnings growth projections
17 from at least two sources is also intended to satisfy the underlying assumptions of the DCF model.
18 The theory is that investors would not continue to invest in a company that did not have positive
19 expected growth over the long term. In Concentric's proxy group screening, it requires that a
20 company have positive growth rates from at least two sources. In Concentric's view, it is important
21 that there be market data available from more than one source, which helps to ensure that the
22 growth rate represents a consensus view, rather than the forecast of a single analyst. As with the
23 other proxy group screening criteria, the purpose of these two screens is to ensure that Concentric's
24 proxy group for NS Power is representative of the Company's business and financial risks.

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1 **Request IR-106:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 36 of 87**

4
5 **Please explain how the conclusion that NS Power competes for capital equally in the United**
6 **States accounts for the restrictions on non-Canadian ownership of voting shares and voting**
7 **restrictions imposed by the *Nova Scotia Power Privatization Act*, SNS 1992, c 8 and the *Nova***
8 ***Scotia Power Reorganization (1998) Act*, SNS 1998, c 19.**

9
10 Response IR-106:

11
12 As a preliminary matter, Concentric does not see the referenced conclusion in its Report. On p. 10
13 of its Report, Concentric indicates “NSPI must compete for capital with other subsidiaries
14 including Tampa Electric Company, which has a much higher authorized ROE and approved
15 common equity ratio in Florida.” On p. 32, Concentric discusses the relevance of U.S. and
16 Canadian proxy groups and we state “Multiple regulatory authorities in Canada have recognized
17 that Canadian utility companies are competing for capital in global financial markets and that
18 Canadian data are limited by the small number of publicly-traded utilities. Regulators have also
19 recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the
20 utility regulatory regimes.”

21
22 Emera is a publicly listed company on the Toronto Stock Exchange (“EMA”) and on the New
23 York Stock Exchange (“EMA”), and Concentric’s understanding is that these actions are
24 consistent with ownership restrictions of the Nova Scotia Power Privatization Act and the Nova
25 Scotia Power Reorganization Act. In 2019 the legislature and Emera shareholders lifted restrictions
26 on Emera foreign ownership.

27
28 Recognizing that Emera raises capital in global capital markets, NS Power is subject to that same
29 competition for equity capital. NS Power has the lowest allowed weighted return on equity
30 (including both the ROE and equity ratio) of any North American vertically integrated electric

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- 1 utility, which places the company at a competitive disadvantage for raising capital internally and
- 2 externally.

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1 **Request IR-107:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 37 of 87**

4
5 **Please confirm, or explain otherwise, that on the same page referenced from the recent**
6 **Ontario Energy Board generic cost of capital decision (EB-2024-0063) the OEB also stated:**

7
8 **The integration of U.S. and Canadian utility markets and the potential**
9 **lure of higher returns for investors is a factor to be considered in**
10 **arriving at a final conclusion concerning the requisite ROE that must**
11 **be provided to meet the FRS. However, the use of U.S. regulated utility**
12 **data as equivalent to Canadian regulated utility data in any**
13 **computation is questionable.**

14
15 **Response IR-107:**

16
17 Concentric confirms the above statement from the Ontario Energy Board in its recent GCOC
18 decision. Concentric explains its reasons for using a North American proxy group on pages 32-33
19 of its report, including the recent precedent in British Columbia and Alberta and the 2009 decision
20 of the National Energy Board (now the Canada Energy Regulator) for doing so. Further, in the
21 most recent Ontario GCOC in 2024, the OEB's own expert, London Economics International, also
22 used a North American proxy group that included both Canadian and U.S. electric and gas utilities
23 as comparators for Ontario's regulated utilities.

24
25 Concentric continues to support the conclusion in its report: "Since the NEB's 2009 decision, the
26 utility industry has become even more of a North American industry from both an investor and
27 allocation of capital viewpoint. Our view is that careful screening of a North American proxy
28 group of companies remains the most reliable method for determining the cost of capital, and is
29 consistent with how investors see the market."

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Request IR-108:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, Figure 19, page 43 of 87

- (a) Please confirm, or explain otherwise, that the Canadian Utility results are heavily influenced by Enbridge Inc., which was noted on page 41 of 87 to have had a significant increase in its payout ratio.**
- (b) Please confirm, or explain otherwise, that excluding Enbridge Inc. from the Canadian Utility results produces a Multi-Stage DCF result of 9.13% (including “flotation costs and financial flexibility”).**

Response IR-108:

- (a) Confirmed. Enbridge, Inc., however, is not included in Concentric’s North American Electric proxy group, which formed the basis for its ROE recommendation of 9.90 percent for NS Power. Further, the increase in the dividend payout ratio for Enbridge, Inc. noted in the question was a management decision that was intended to provide a competitive total return to current and potential investors, so that Enbridge, Inc. could continue to attract capital on reasonable terms. Enbridge, Inc. targets a dividend payout ratio of 60-70 percent of distributable cash flow, which allows the company flexibility to retain cash for growth-related projects and debt management. More recently, Enbridge, Inc. has acquired gas distribution utilities in the U.S. states of North Carolina, Ohio, Utah, Idaho and Wyoming.**
- (b) Confirmed.**

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1 **Request IR-109:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, Figure 24, page 49 of 87**

4
5 **Please confirm, or explain otherwise, that using the historical Canadian MRP rather than**
6 **an average of Canadian and US MRPs produces a CAMP result (including flotation costs)**
7 **of 9.06%.**

8
9 **Response IR-109:**

10
11 Confirmed. As explained on page 43 of Concentric's report, "Because the U.S. and Canadian
12 economies are highly integrated and capital flows freely across the border, the risk premiums for
13 each country are highly correlated. Accordingly, it is reasonable to derive a single estimate of the
14 MRP for Canada and the U.S." Concentric also notes that the historical MRP has increased to
15 5.75 percent in Canada and 7.31 percent in the U.S., based on Kroll data that includes 2024 market
16 returns.

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1 **Request IR-110:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 43 of 87**

4
5 **With respect to Flotation Costs and Financing Flexibility:**

6
7 **(a) Please confirm, or explain otherwise, that a 50-basis point allowance for flotation**
8 **costs and financing flexibility amounts to approximately \$11.2 million in 2026 and**
9 **\$11.8 million based on NS Power's forecast average common equity in those years.**

10
11 **(b) Please provide actual costs incurred by or allocated to NS Power for the past five**
12 **years associated with the sale of new issues of common equity, including out-of-pocket**
13 **expenditures for the preparation, filing, underwriting, as well as a discount to the**
14 **share price, and other costs of issuance of common equity.**

15
16 **(c) Please elaborate as to why a 50-basis points flotation costs is appropriate for NS**
17 **Power.**

18
19 **Response IR-110:**

20
21 **(a) Confirmed.**

22
23 **(b) NS Power does not directly incur costs related to Emera equity issuances and such costs**
24 **are not directly allocated to NS Power; however, Emera is compensated for those costs by**
25 **NS Power through dividends, which account for the flotation and financial flexibility costs**
26 **included in NS Power's ROE.**

27
28 **(c) Please see pages 44-46 of Concentric's report for a discussion of why the proposed**
29 **adjustment for flotation costs and financial flexibility is appropriate for NS Power. In**
30 **particular, the majority of Canadian regulators have approved an adjustment of 50-basis**

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1 points for flotation costs. Furthermore, in his recent testimony in NSPML's assessment
2 application, Dr. Sean Cleary on behalf of Board Counsel also recommended an adjustment
3 to the authorized ROE of 50-basis points for flotation costs and financing flexibility. From
4 an accounting perspective, the costs of issuing common equity are not expenses that are
5 recorded on the utility's income statement, but rather are recorded on the balance sheet of
6 the company. If NS Power is not allowed to recover these costs, this will further diminish
7 the Company's authorized ROE in relation to its peers.

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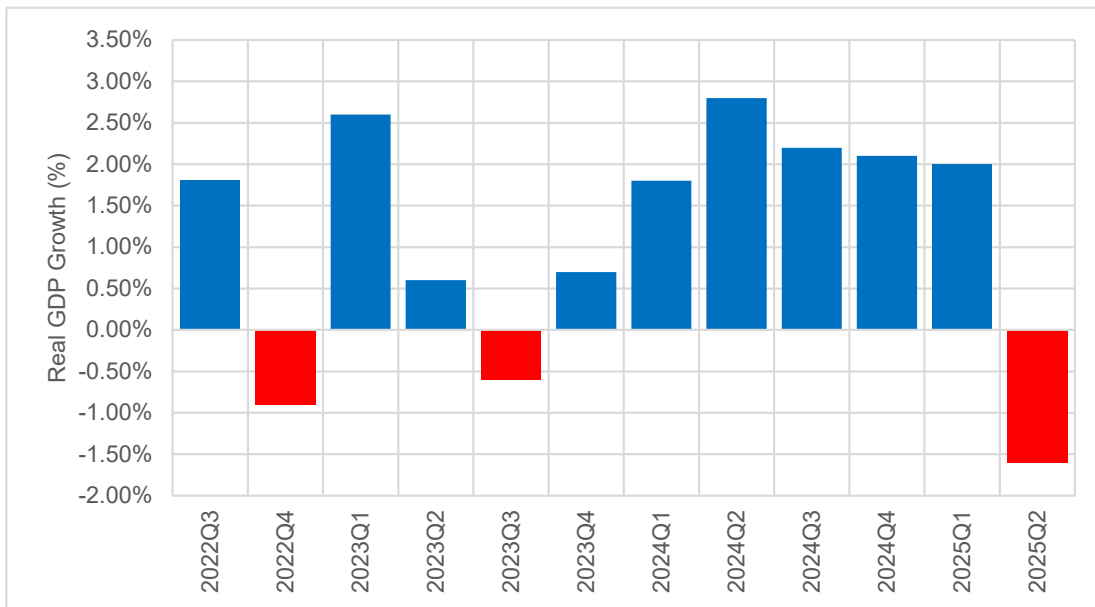
Request IR-111:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 16 of 87

**Concentric refers to Canada's GDP growth increasing in Quarters 2 to 4 throughout 2024.
Please update Figure 2 with Canada's GDP growth to Q2 2025.**

Response IR-111:

Figure 2 has been updated, as requested. Real GDP contracted at an annualized rate of 1.6 percent in the second quarter of 2025, according to Statistics Canada. According to both Consensus Economics and the Conference Board of Canada, real GDP growth over the long-term is expected to be around 2.0 percent. That is the growth rate Concentric used in the third stage of its Multi-Stage DCF model.



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Request IR-112:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 17 of 87

Concentric notes Canada's unemployment rate was 6.6% in February 2025 and explains that the unemployment rate is an indicator of the strength of the economy.

(a) Please confirm that Concentric considers Canada's unemployment rates over the past 10 years, as presented in Figure 3: Canadian Unemployment Rate, as demonstrating stability, outside of COVID-19 pandemic period.

(b) Does Concentric regard the Figure 3 to be reflective of more, less or the same volatility as Figure 6?

Response IR-112:

(a) Concentric agrees that the unemployment rate in Canada has been relatively stable over the past 10 years, except during the COVID period.

(b) The unemployment rates in Canada and the U.S. have followed a similar path since 2015 in terms of variability. As shown in Exhibit CEA-2, the average unemployment rate in Canada from 2015-2024 has been significantly higher, at 6.62 percent as compared to 4.75 percent in the U.S.

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Request IR-113:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 18 of 87

Concentric states “For many years, consumer prices in Canada increased by less than 2.0 percent.” Please state the years before 2021 that Concentric is referring to.

(a) Please confirm that the Bank of Canada has an inflation-control target range of 1-3%.

(i) Please identify the years before 2020 where inflation was outside of the target range of 1-3%.

(ii) Please confirm, or explain otherwise, that CPI in Canada was within the Bank of Canada’s target range in 2024.

(b) In reference to CPI 2023, 2024 and 2025:

(i) Please compare these figures to the United States.

(ii) Does Concentric regard the CPI figures for 2023 and 2024 and the recent 2025 estimates as high and/or unstable?

(c) On page 32 of 87, Concentric states at line 23 “inflation has gradually declined to levels slightly above central bank targets”. Please confirm that Canada’s current Total CPI to be within the Bank of Canada’s target rather than above target.

Response IR-113:

(a) Confirmed.

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- 1 (i) As shown in Exhibit CEA-2, the CPI in Canada was below 1.0 percent in
2 2013 and 2009. It was within the Bank of Canada's target range of 1.0 to
3 3.0 percent in all other years from 2000-2019.
- 4 (ii) The Bank of Canada's preferred measure of inflation is CPI Trimmed
5 mean, as described on page 14 of Concentric's report. In 2024, the CPI
6 Trimmed mean was 2.4 percent, within the Bank of Canada's target range,
7 but above the midpoint.
- 8 (b)
- 9 (i) Exhibit CEA-2 shows that CPI in the U.S. was slightly higher than in
10 Canada in 2023. In 2024, the CPI declined in Canada to 2.4 percent as
11 compared to 2.9 percent in the U.S. Inflation has remained near these
12 levels for much of 2025.
- 13 (ii) Inflation in 2021-2023 was well above the historical average in both
14 countries. Inflation has gradually declined and is nearing historical
15 average levels, but remains above the target of central bankers in both
16 Canada and the U.S.
- 17
- 18 (c) As stated above, the Bank of Canada's preferred measure of inflation is CPI Trimmed
19 mean. On that basis, the most recent measure of inflation in Canada as of September 2025
20 was 3.10 percent, or slightly above the Bank of Canada's target range.

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1 **Request IR-114:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 32 of 87**

4
5 **Concentric's capital analysis concludes that Canada and the U.S. are comparable in terms**
6 **of macroeconomic and investment environments and therefore it is reasonable to use U.S.**
7 **proxy companies.**

8
9 **(a) Have any of the listed U.S. proxies determined their Capital Structure using**
10 **Canadian proxies?**

11
12 **(b) If so, please identify which utilities and the Canadian proxies used.**

13
14 **Response IR-114:**

15
16 (a) It is not clear whether the question is referring to how utilities determine their actual capital
17 structure, or how regulators set the deemed or authorized capital structure. Concentric does
18 not know how each of the proxy group companies determine their actual capital structure,
19 but to the extent U.S. companies are competing in North American capital markets,
20 Concentric would expect them to consider available data for companies in Canada as well.
21 Concentric is not aware of any state regulators in the U.S. that have considered Canadian
22 companies in determining the capital structure for a U.S. regulated utility, although the
23 Federal Energy Regulatory Commission does allow U.S. pipeline companies to include
24 Canadian companies in the proxy group for cost of capital purposes.

25
26 (b) Please see response to part (a) above.

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1 **Request IR-115:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 36 of 87**

4
5 **Page 36 states at lines 1-2, “Canadian regulators have adopted a pragmatic view of the use**
6 **of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities.”**
7 **Please list the regulators, and the type of utilities, that have adopted the use of U.S. data and**
8 **proxy groups for estimating ROE since 2022.**
9

10 Response IR-115:

11
12 As discussed on pages 32-33 of Concentric’s report, both the British Columbia Utilities
13 Commission and the Alberta Utilities Commission recently employed North American proxy
14 groups in establishing the authorized returns for regulated electric and gas utilities. Furthermore,
15 the Ontario Energy Board’s own expert, London Economics International, used a North American
16 proxy group that included both Canadian and U.S. electric and gas utilities as comparators for
17 Ontario’s regulated utilities, even though the OEB’s decision questioned whether U.S. companies
18 have comparable regulatory risk. In Prince Edward Island, London Economics was also retained
19 by the Island Regulatory and Appeals Commission to recommend a cost of capital for Maritime
20 Electric. As in Ontario, London Economics developed a proxy group consisting of North
21 American electric utilities in its report. The Commission issued an order approving the settlement
22 agreement in that case in April 2023.

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1 **Request IR-116:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 42 of 87**

4
5 **Page 42 at lines 15-16 state “In the terminal stage, the dividend cash flow then grows in**
6 **perpetuity at the same rate as nominal GDP (or a total of 200 years).” Please elaborate on**
7 **why it is reasonable to assume NS Power’s dividend cash flow will grow at the same rate as**
8 **GDP in perpetuity.**

9
10 **Response IR-116:**

11
12 See Figure 17 on page 36 of Concentric’s report for a comparison of historical earnings per share
13 and dividend per share growth for the various proxy groups to both historical and forecast GDP
14 growth. That analysis demonstrates that the growth in earnings and dividends per share has been
15 very similar to nominal GDP growth between 2009-2024. Concentric expects that relationship to
16 continue, so Concentric believes it is reasonable, if not conservative, to use GDP growth as the
17 terminal growth rate in the Multi-Stage DCF model for purposes of estimating the ROE for NS
18 Power.

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Request IR-117:

Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report Figure 32: 2023 S&P Credit Metrics Comparison.

(a) Please breakout the column for Canadian by the Canadian Electric Utilities listed in Figure 31.

(b) Please update using 2024 S&P Credit Metrics.

Response IR-117:

(a) Please see the table below. The Canadian utilities included in the table are the regulated operating companies of Hydro One Ltd. and Fortis Inc. Canadian Utilities Ltd. is not rated by S&P Global, so credit metrics are not available for ATCO Electric.

Credit Metric	Canadian Electric
Debt to Capital Ratio	58.6%
EBITDA to Interest Coverage	3.92
FFO to Interest Coverage	3.90
FFO / Debt (%)	12.0%
Debt / EBITDA	6.19

(b) Please see Attachment 1 for the updated credit metrics for 2024. Please note that 2024 credit metrics are not yet available for American Electric Power, Inc.

**2026-2027 GRA NSEB IR-117 Attachment 1 has been
filed electronically.**

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1 **Request IR-118:**

2
3 **Reference: Exhibit N-8, Appendix 10A, Cost of Capital Report, page 68 of 87**

4
5 **Page 68 references a December 2024 economic forecast by TD Economics and the Conference**
6 **Board of Canada forecast from April 2024.**

7
8 **(a) On September 22, 2025, TD Economic published a new Provincial Economic forecast.**
9 **The current forecast contradicts several of the weaknesses identified by Concentric**
10 **such as a limited rise in unemployment; expected spending in the province by federal**
11 **government's large defense spending plan; positive performance in the goods sector**
12 **despite Chinese tariffs on seafood; manufacturing sales up; and construction is strong**
13 **in both residential and non-residential. Does this current forecast change**
14 **Concentric's expectations of Nova Scotia's macroeconomic situation? Please explain.**
15

16 **(b) Concentric cites a Conference Board of Canada prediction in (c) on page 69 of 87,**
17 **that business investment will be weak because there are no major capital projects in**
18 **the long term and housing has slowed. However, in February 2025 the Nova Scotia**
19 **government announced a \$2.35 billion capital plan for healthcare and housing**
20 **projects. More recently, in September, the Federal Government created a Major**
21 **Projects Office and identified strategic areas of focus, including Wind West Atlantic**
22 **Energy and the Eastern Energy Partnership for the development of new offshore**
23 **wind resources and related energy infrastructure projects. Do these recent major**
24 **project investments change Concentric's expectations of weak business investment**
25 **due to a lack of major capital projects and slower housing?**
26

27 **Response IR-118:**

28
29 **(a) No, the September 2025 report from TD Economics does not materially change the near-**
30 **term economic outlook for Nova Scotia as compared to the December 2024 version of the**

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1 same report cited on page 63 of Concentric's cost of capital report. In particular, the
2 unemployment rate in Nova Scotia is now projected at 7.0 percent in 2026 (compared to
3 6.9 percent in the December 2024 report) and real GDP is now projected to grow by 1.4
4 percent in 2026 (compared to 1.3 percent in the December 2024 report). As shown on page
5 12 of the September 2025 TD Economics report, the 2027 forecast for Nova Scotia is below
6 the national average for both economic growth (1.7 percent vs. 1.2 percent in Nova Scotia)
7 and unemployment (6.3 percent vs. 6.8 percent in Nova Scotia). Furthermore, from a cost
8 of capital perspective, the long-term economic and demographic trends in the province are
9 more relevant to Concentric's analysis. Those are captured in the Conference Board of
10 Canada's report.

- 11
- 12 (b) No. The Conference Board of Canada published an updated long-term forecast on March
13 17, 2025. The Key Findings from that report are summarized below and are generally
14 consistent with those from the April 2024 Conference Board outlook that is cited in
15 Concentric's report. In particular, the Conference Board continues to find that the long-term
16 outlook for business investment and housing starts is weak in Nova Scotia. Concentric's
17 understanding is that the Wind West Atlantic Energy and Eastern Energy Partnership is
18 currently in the initial planning and development stages, with a formal bidding process
19 expected soon and construction to begin potentially between 2031 to 2033. Until there is
20 more certainty around this offshore wind project, the timing and economic impact on the
21 province are difficult to forecast.

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Key findings

- Real GDP growth in Nova Scotia is expected to be modest over the long term, with average annual gains of 1.5 per cent between 2025 and 2045.
- Demographics will drag down output over the outlook period as population growth slows drastically. International migrants will be the main source of population growth.
- Labour force growth will slow due to limited new labour market entrants. Subsequently, consumer spending growth will be constrained by the reduced spending power of an aging population.
- The outlook for business investment is weak, as no major capital projects are in the pipeline in the long term and housing starts are forecast to decline.
- Nova Scotia's finances face structural challenges as an older population will demand more government services while economic growth slows.
- Manufacturing is one of the few bright spots on the industry side, with real output growth expected to average a healthy 3.1 per cent between 2025 and 2045.

1
2

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Request IR-119

Reference: Exhibit N-8, Appendix 10A, CEA exhibits EO, CEA Summary -1

In CEA Summary -1, why do the proxies use calculated ROEs instead of their Regulated ROE?

a) Please provide the approved ROE for each proxy company in CEA-1.

Response IR-119:

Please see Request IR-119, Attachment 1 for the authorized ROEs for each operating utility company held by the proxy group companies.

Exhibit CEA-1 summarizes the results of Concentric's various ROE analyses, including the DCF, CAPM and Risk Premium approaches, for the Canadian, U.S. Electric, and North American Electric proxy group. Our ROE recommendation for NS Power is based on the three-model average results for the North American Electric proxy group. The authorized ROEs provided in Attachment 1 also are relevant as a benchmark for investors as they develop their return requirements. Concentric notes that the authorized ROE for regulated electric and gas utilities under the Ontario formula increased from 9.00 percent to 9.11 percent for 2026 in a letter published by the OEB on October 31, 2025.

**2026-2027 GRA NSEB IR-119 Attachment 1 has been
filed electronically.**

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Request IR-120:

Reference: Exhibit N-8, Appendix 10A, CEA exhibits EO, CEA-2 Macroeconomic worksheet

(a) Real GDP Growth for Canada 2024 as 1.52808110779434 from Statistics Canada Table 36-10-0104-01 Gross domestic product, expenditure-based, Canada.

(i) Please confirm that the data collected was seasonally adjusted at annual rates.

a. If confirmed, please confirm or explain otherwise that Real GDP Growth in Canada was 1.6 percent in 2024 according to Statistics Canada Table 36-10-0104-01 Real gross domestic product by expenditure account, year-over-year change – seasonally adjusted at annual rates, chained (2017) dollars.

(b) CPI Change Canada uses Statistics Canada; Consumer Price Index, All items, not seasonally adjusted, please confirm, or explain otherwise, that CPI for 2014 was 2.0 percent.

(c) Please provide the data and calculations for Exports Canada to U.S./Canadian GDP and U.S. to Canada/U.S. GDP.

Response IR-120:

(a) Not confirmed. The GDP data reported in Exhibit CEA-2 was calculated based on quarterly (not annual) data from Statistics Canada. The data is seasonally adjusted.

(i) Concentric's report cites a GDP growth rate for Canada of 1.60 percent in 2024, which was the figure reported by Trading Economics, which obtains its GDP data from the OECD rather than Statistics Canada.

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- 1 (b) Not confirmed. As shown in Exhibit CEA-2, the CPI change for Canada in 2014 was 1.91
2 percent.
3
4 (c) Please see Attachment 1 for the requested data and calculations.

**2026-2027 GRA NSEB IR-120 Attachment 1 has been
filed electronically.**

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Request IR-121:

Reference: Exhibit N-8, Appendix 10A, CEA-5 Multi-Stage DCF

CEA-5 Multi-Stage DCF, column [9] uses a GDP Growth (perpetuity) from Consensus Economics Consensus Forecast October 7, 2024, for 2030-2034 = (GSP x (1+ CPI)) +CPI. The Canadian Proxy Group formula uses = (0.019 x 1.21) +0.021 and the U.S. Electric Proxy Group formula uses = (0.019 x 1.22) +0.022.

(a) Is the Canada Proxy Group GDP estimate for Canada or Nova Scotia or the U.S.?

(b) Is the Canada Proxy Group CPI estimate for Canada or Nova Scotia or the U.S.?

(i) Why has the mid point of the Bank of Canada's inflation target range not been used for the Canada Proxy Group?

Response IR-121:

(a) The nominal GDP growth rate for the Canadian proxy group in Concentric's Multi-Stage DCF model is based on the forecast from Consensus Economics for Canada from 2030-2034.

(b) The CPI growth rate for the Canadian proxy group in our Multi-Stage DCF model is based on the forecast from Consensus Economics for Canada from 2030-2034.

(i) The midpoint of the Bank of Canada's inflation target range is 2.0 percent compared to the CPI forecast from Consensus Economics of 2.1 percent. There is not a material difference in these two values. Concentric's preference is to continue using the consensus forecast of economists and analysts surveyed by Consensus Economics.

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Request IR-122:

Reference: Exhibit N-3, GRA Direct Evidence

On pages 68-69 of the application, NS Power states that it forecasts to be above the 10% FFO-to-Debt requirement to maintain its current credit ratings, assuming approval of the proposed rates in the application and a successful securitization of the net book value of the thermal assets. Otherwise, it projects it would fall below the 10% threshold by 2027 (ref. to Figures 10-2 and 10-3).

(a) Please provide the estimated percentage FFO-to-Debt for both S&P and DBRS (for both test years) if the securitization does not occur.

Response IR-122:

(a) Please see the table below for NS Power's estimate of FFO to Debt credit metrics provided securitization does not occur. To calculate these figures, NS Power assumed no additional revenue over the 2026-2027 test period and all depreciation and financing expense associated with the assets to be securitized is deferred.

	2026 (Percent)	2027 (Percent)
S&P Credit Metrics GRA Forecast	12.3	12.8
S&P Credit Metrics without Securitization	10.7	11.2
DBRS Credit Metrics GRA Forecast	12.1	12.7
DBRS Credit Metrics without Securitization	10.7	11.1

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Request IR-123:

Reference: GRA Direct Evidence, Appendix 10A

Since the 2023-2024 GRA was conducted, a number of significant developments have occurred or are planned:

- In April 2024 in Matter M11393, the Board approved a Fuel Adjustment Mechanism (FAM) Rider that followed the sale of \$117 million in unrecovered fuel costs from NS Power to the Province, deferring the collection from ratepayers over a 10-year period (2024 NSUARB 71).**
- In November 2024 in Matter M11791, the Board approved a Supplemental Assessment by NSPML, representing the annual amount recoverable from NS Power and charged to NS Power's customers, when NSPML issued \$500 million of new debt repayable over 28 years supported by a Government of Canada Federal Loan Guarantee, with the \$500 million (less financing fees) refunded to NS Power's customers to be applied against the FAM balance of unrecovered fuel costs.**
- The Bank of Canada's overnight rate has decreased from 3.25% on September 8, 2022 (and later at 3.75% on October 27, 2022) down to 2.5% as of September 17, 2025.**
- In February 2024, the Province passed the Energy Reform (2024) Act, which provided for the creation of the Nova Scotia Independent Energy System Operator (NSIESO). This statute will transition NS Power's system planning, transmission interconnection and energy and capacity procurement functions to the NSIESO, starting with a transfer of some of the functions in October 2025.**
- In the present application, NS Power stated it intends to apply to the Board for approval for the securitization of about \$704 million of thermal assets by the end of 2025, saving customers as much as \$90 million over 2026-2027 by removing these assets from NS Power's rate base and financing them through lower-cost debt.**

(a) Please confirm that the above factors each have a positive impact on the business and/or financial risk profile of NS Power. If not, why not?

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1 **(b) How did Concentric reflect the above factors in its ROE analysis prepared for NS**
2 **Power?**

3
4 **(c) Given the above developments, why was Concentric's recommended ROE for NS**
5 **Power not materially lower than in its evidence in the 2023-2024 GRA?**

6
7 Response IR-123:

8
9 (a) Impact on NSPI's business and/or financial risk.

- 10
11 • *Fuel Adjustment Mechanism (FAM) Rider with sale of \$117 million in unrecovered*
12 *fuel costs from NS Power to the Province and recovery from ratepayers over a 10-*
13 *year period; and then Supplemental Assessment with NSPML issuance of \$500*
14 *million of new debt guaranteed by the Government of Canada:* Both of these
15 provisions are beneficial to NS Power and its customers because they take a short-
16 term problem (high FAM balance) and stretch this obligation out over 10 to 28
17 years. These are unusual provisions necessitated by a build-up of large FAM
18 balances uncommon for other utilities. From a near-term financial risk perspective,
19 it is a positive development as it improves NS Power's cash position by a combined
20 \$617 million, and was a principal factor in S&P's revised credit outlook for Emera
21 and its subsidiaries, including NS Power, from BBB- Negative to BBB- Stable
22 (2026-2027 GRA NSEB IR-102 Attachment 2). DBRS did not change its credit
23 rating, where it remains at BBB (High) (GRA NSEB IR-102 Attachment 1). The
24 benefits of these provisions largely accrue to customers through a longer-term
25 solution that smooths out the rate impact of fuel costs incurred by NS Power on
26 their behalf. From a utility investor's standpoint, the build-up of an unrecovered
27 fuel cost balance is uncommon. Fuel cost recovery mechanisms are typically
28 designed to clear within a one-year period. These solutions are therefore a positive
29 development, but do not completely offset the problem of fuel costs incurred in a
30 prior period being recovered in future periods. As Concentric concluded on page

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66 of its Report, the design of NSPI's FAM, including the bi-annual audit and the associated regulatory lag, translate into elevated risk on this factor relative to its Canadian and U.S. peers. These transactions do not alter this conclusion.

- *Bank of Canada's overnight rate reduction from 3.25% in September 2022 to 2.5% in September 2025:* The BOC's overnight rate has the greatest impact on short-term interest rates (NS Power's forecasted capitalization for the test period includes approximately 5 percent short term debt). A reduction has a nominal impact on NS Power's business or financial risk, although is generally favorable for the economy and customers. Longer term interest rates are more important to NS Power's operations as the company principally finances its operations with longer-term debt and equity. Concentric captures the impacts of changes in long-term interest rates in its cost of capital analysis (see Concentric Report, p. 40). The benchmark 30-year Government of Canada bond yield has increased since September 2022 from a range of 3.0 – 3.25 percent to the current level of 3.6 percent. There is no reduction in risk from this trend.

- *Energy Reform (2024) Act, which provided for the creation of the Nova Scotia Independent Energy System Operator:* As indicated on p. 65 in Concentric's Report:

Another factor impacting NSPI's operating risk is the recent passage of the Energy Reform (2024) Act. The Act represents the potential for a significant shift in both the regulation and operations of the electric industry in the Province. As the provisions of the Act come into force, NSPI's historic role of control of the bulk power grid is intended to shift to the IESO, and greater competition will be introduced into the wholesale power market. The impacts on NSPI business and its operating risks will be determined as the Act's new policy direction is implemented, but creates uncertainty from an investor perspective.

As noted by DBRS in its most recent credit rating report for NS Power:

The NSIESO will be tasked with operating the Provincial electricity grid as well as energy forecasting and resource planning. This will streamline

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1 NSPI's responsibilities so it can focus on its operations as an integrated
2 utility. Importantly, while the Company will still be required to adhere to
3 climate change regulations and, as the dominant utility in the Province, be
4 involved in the transition, the responsibility for procuring renewable energy
5 in the Province and meeting targets under the Renewable Electricity
6 Regulations (RER) are expected to be transferred to the NSIESO.

7
8 While these developments will strengthen NSPI's financial metrics and
9 reduce uncertainty under the RER, we remain concerned about potential
10 political interference in the next regulatory review process. (DBRS, Nova
11 Scotia Power Inc., January 15, 2025, 2026-2027 GRA NSEB IR-102
12 Attachment 1)

- 13
14 • *NS Power's plan to apply to the Board for approval for the securitization of about*
15 *\$704 million of thermal assets by the end of 2025, saving customers as much as \$90*
16 *million over 2026-2027 by removing these assets from NS Power's rate base and*
17 *financing them through lower-cost debt.*: Given that the plan has yet to be submitted
18 or approved, there is no change in business risk at this time. Operationally, NS
19 Power will continue to operate these generation facilities and be subject to ongoing
20 capital and maintenance obligations. Financially, the DDA provided a pathway for
21 recovery of these prudently incurred costs. The securitization plan, if approved,
22 stretches out the financial recovery of these costs from customers, but accelerates
23 cost recovery for NS Power. Prospectively, there is a net reduction in financial risk
24 with approval of such a plan, but the larger operational risks remain and financially
25 NS Power experiences a reduction in earnings from the removal of a significant
26 portion of NS Power's rate base (approximately 12% of ending 2025 rate base). On
27 balance, Concentric views the securitization plan as a mechanism that will improve
28 NS Power's credit metrics, provide a benefit to customers through lower rates, and
29 finally facilitate progress towards the Province's energy transition.

30
31 (b) Concentric addressed each of these risks and/or impacts in its cost of capital analysis:

- 32 • FAM related issues – pp 65-66
33 • Bank of Canada actions and interest rates – pp. 18 - 20, 40
34 • Energy Reform (2024) Act – p.65

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- 1 • Thermal asset securitization – pp. 62-63

2

3 (c) Concentric’s ROE analysis is based on market analysis applied to utility industry peer

4 groups. Adjustments to the analysis are made only for material differences between the

5 target company (e.g., Nova Scotia Power) and the peer group. In its prior submission to the

6 Board (2022-2024 GRA Direct Evidence Appendix 9A, January 2022, p. 3), Concentric’s

7 analysis supported a 10.1 percent ROE. In its current evidence, Concentric’s market

8 analysis supports a 9.9 percent ROE (20 basis points lower than its prior evidence), and in

9 both cases the Company has requested a 9.0 percent ROE, well below Concentric’s

10 estimated ROE. There are no material changes to the Company’s risk profile that would

11 otherwise warrant such a downward adjustment.

REDACTED

Request IR-124:

Reference: Exhibit N-3, 11.2 Revenue Requirement Categories

Please reproduce Figure 11-1 with additional columns to show the revenue breakdown for each of 2023, 2024, and 2025.

Response IR-124:

Please refer to the table below. Please note that the 2023 and 2024 figures represent actual results whereas 2025 represents forecast results. NS Power earned below the bottom of its allowed return on equity range in 2023 and 2024 and expects to earn below this range in 2025. NS Power's equity ratio was also below the approved 40 percent in 2023 and 2024, and this is expected to continue in 2025 as the Company did not have sufficient earnings to support the approved level of equity. As such, the return on equity element of the revenue requirement in the table below for 2023-2025 is lower than would be the case if the Company was earning 9 percent on 40 percent equity.

Category (\$ Million)	2023	2024	2025	2026	2027
Fuel & Purchased Power	\$777.0	\$509.2		\$918.6	\$918.4
OM&G	326.0	328.5		351.8	357.9
Demand Side Management Expense	50.0	57.5		63.8	63.8
Depreciation and Accretion	265.4	275.8		282.4	300.8
Taxes (including grants-in-lieu of property taxes)	40.4	14.5		29.7	56.1
Regulatory Amortization (including FAM expense)	(89.3)	352.0		16.8	(1.8)
Interest and Other Expenses (including AFUDC and FAM interest)	145.1	136.7		118.5	130.0
Return on Equity	156.0	179.5		201.0	212.0
Revenue Requirement	1,670.6	1,853.7		1,982.7	2,037.2
Other Revenue	37.3	40.7		45.7	46.9
Revenue Requirement from Electric Rates	1,633.4	1,813.1		1,937.0	1,990.2

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Request IR-125:

Reference: Exhibit N-3, 11.2 Revenue Requirement Categories, p.75 and Exhibit N-6(ii)

In the NSIESO's application for its revenue requirement for the year ending March 31, 2026, it estimated that 23 employees would be transferred from NS Power to the NSIESO in that year. Board staff notes a reference in NS Power's GRA application to three employees transferred under control center labour, and an unspecified number under T&D Contractor Management labour.

(a) Please identify the number of employees forecast to be transferred under T&D Contractor Management in each of 2025 and 2026.

(b) Are there employees under any other cost categories forecast to be transferred to the NSIESO in 2025/2026? If so, please provide the details.

(c) If the total employees forecast to be transferred in 2025/2026 are less than 23, please explain the difference in the forecast from what was provided by the NSIESO.

(d) Please provide an update on the status of employees transferring in phase one.

(e) When does NS Power expect phase two of the employee transfer to occur?

(f) Noting that the NSIESO has forecast phase two of the transfer to occur in Q2 of 2027, why has NS Power forecast the transfer as of the start of 2027?

(g) Is the entire \$4.5 million reduction in 2027 under control center labour?

(h) Is NS Power intending to defer these employees' salaries as incurred as of the start of 2027 if they have not yet been transferred?

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1 **(i) Does NS Power propose to defer this amount until its next GRA?**

2
3 **(j) Will the financial position of the utility factor into a decision to defer the amount? i.e.**
4 **Does NS Power intend to defer the amount even if its 2027 ROE is above the approved**
5 **amount?**

6
7 Response IR-125:
8

9 (a) NS Power forecasts 0 employees in 2025 and 19 employees in 2026 to be transferred to the
10 IESO-NS from T&D Contractor Management.
11

12 (b) No.
13

14 (c) NS Power's forecast may be different from the number of employees IESO-NS leadership
15 determines it requires for a variety of reasons that are not in NS Power's control.
16

17 (d) See NS Power's response to NSEB IR-47(b).
18

19 (e) See NS Power's response to NSEB IR-47(b).
20

21 (f) NS Power's forecast was based on a point in time. The IESO-NS communicated an April
22 1, 2027 Phase II transition date in late October 2025. As referenced in NSEB IR-47(b), the
23 timing remains uncertain and will depend on the resolution of several developing factors
24 that determine readiness.
25

26 (g) The \$4.5 million reduction in Control Centre in 2027 is primarily Labour: \$4.4 million with
27 \$0.1 million related to non-labour employee costs such as training, travel and telephones.
28

29 (h) Confirmed.
30

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- 1 (i) NS Power proposed to defer this amount until the next GRA, or alternative appropriate rate
2 hearing as identified (i.e. An IESO-NS tariff proceeding).
3
- 4 (j) The development and costs associated with the IESO-NS development remain fluid and
5 therefore NS Power would need to make that determination with respect to recovery at the
6 time.

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Request IR-126:

Reference: Exhibit N-3 GRA Direct Evidence, 11.2 Revenue Requirement Categories, p. 74

NS Power requests the ability to create a deferral to allow it to recover the incremental tax expense of approximately \$7.0 million if the EIFEL exemption is not enacted.

(a) Does NS Power propose to defer this amount only if total expense is at least \$7.0 million higher than forecast in the GRA test year forecast?

(i) If not, why should NS Power be able to defer this amount if other tax related items are under forecast and offset the increase?

Response IR-126:

(a) No, NS Power is proposing to defer the cost, regardless of its amount.

(i) The EIFEL exemption has been identified as a fluid tax policy issue, the outcome of which NS Power has no ability to control. By seeking the deferral, NS Power is attempting to save customers money.

Currently, the approximately \$7 million expense is a forecast cost to NS Power and its customers. As NS Power believes there is a high potential that the exemption is granted, it has elected to remove the expense from its forecast revenue requirement and instead request that, if the exemption is not granted, NS Power is provided with the ability to recover these tax expenses. However, to be absolutely clear, in the absence of the deferral, the expense should be included in forecast revenue requirement.

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Request IR-127:

Please provide a table, similar to the table in Exhibit N-9, Appendix 12A(3), on p. 242 of 310, comparing allocated costs under the existing and proposed cost of service methodologies.

Response IR-127:

2026 COSS

	Change on Total Allocated Costs in \$ Million				Revenue to Expense Ratio		
	Demand	Energy	Customer	Total	Current COSS	Proposed COSS	Change
(1) Domestic	104.3	(91.7)	13.4	26.0	97.1	97.2	0.1
(2) Small General	5.3	(6.1)	0.6	(0.1)	101.4	103.5	2.1
(3) General	29.1	(37.3)	0.4	(7.8)	104.4	104.4	(0.0)
(4) Large General	3.3	(5.6)	0.0	(2.4)	104.4	104.4	(0.0)
(5) Small Industrial	3.0	(4.2)	0.1	(1.2)	104.3	104.4	0.0
(6) Medium Industrial	3.8	(7.0)	0.0	(3.2)	104.4	104.4	(0.0)
(7) Large Industrial	5.8	(10.8)	0.0	(5.0)	104.4	104.4	(0.0)
(8) PHP	5.0	(10.3)	0.0	(5.3)	104.4	104.4	(0.0)
(9) Municipal	2.2	(2.1)	0.0	0.1	104.4	104.4	(0.0)
(10) Unmetered	0.8	(1.2)	0.2	(0.2)	100.0	100.0	-
(11) Sub-Total	163	(176)	-	-	100.0	100.0	-

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1 2027 COSS

	Change on Total Allocated Costs in \$ Million				Revenue to Expense Ratio		
	Demand	Energy	Customer	Total	Current COSS	Proposed COSS	Change
(1) Domestic	127.71	(114.52)	12.13	25.32	97.2	97.2	0.0
(2) Small General	6.78	(7.69)	0.73	(0.18)	102.3	104.7	2.3
(3) General	35.13	(45.77)	0.49	(10.14)	104.7	104.7	(0.0)
(4) Large General	3.96	(7.07)	0.01	(3.10)	104.7	104.7	(0.0)
(5) Small Industrial	3.69	(5.28)	0.09	(1.50)	104.7	104.7	(0.0)
(6) Medium Industrial	4.23	(8.37)	0.01	(4.12)	104.7	104.7	(0.0)
(7) Large Industrial	7.05	(13.51)	0.01	(6.45)	104.7	104.7	(0.0)
(8) PHP	6.49	(4.43)	0.01	2.07	N/A	N/A	-
(9) Municipal	2.68	(2.71)	0.00	(0.02)	104.7	104.7	(0.0)
(10) Unmetered	0.99	(1.58)	0.21	(0.37)	100.0	100.0	-
(11) Sub-Total	-	-	-	-	100.0	100.0	-

2

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1 **Request IR-128:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 12 Cost of Service, p.76**

4
5 **NS Power notes that “the Parties are in agreement that the use of the Minimum System**
6 **methodology after the 2026-2027 test period will be subject to a future proceeding and**
7 **determination by the Board, for which an application will be made in 2026”. Board staff**
8 **notes that the Board stated the following in a recent rate application of Mahone Bay: “The**
9 **Board anticipates that [use of the minimum system method] may be one that is more**
10 **thoroughly considered in this jurisdiction when NS Power completes its next cost-of-service**
11 **study, which is expected no later than December 31, 2025” [2023 NSUARB 66].**

12
13 **(a) Please provide the outcome of the cost of service study if the distribution**
14 **classifications that have used the minimum system methodology instead were**
15 **classified 100% to demand.**

16
17 **(b) Please provide Figure 14-1 “Percentage Increase by Customer Class” that would**
18 **result if the change noted in part a) was made to the cost of service.**

19
20 **Response IR-128:**

21
22 **(a-b) Please refer to Attachment 1. The Company is proposing the continued use of the Minimum**
23 **System Study as part of the consensus GRA and has not completed the computation of**
24 **rates for this alternative scenario and therefore is unable to provide a revised Figure 14-1.**

**2026-2027 GRA NSEB IR-128 Attachment 1 has been
filed electronically.**

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1 **Request IR-129:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 12.4 PHP COSS Treatment**

4
5 **On page 79 of 99, NS Power stated:**

6
7 **In addition, PHP's ATL treatment includes the value of priority interruption**
8 **service provided, if any. For the purpose of modelling, the value of priority**
9 **interruption service has been applied as a 10 percent premium to the LIIR**
10 **credit.**

11
12 **(a) Please explain how the priority interruption service would differ from the current**
13 **practice.**

14
15 **(b) Please list the number of PHP interruptions during the past three years, as well**
16 **as during 2025 YTD.**

17
18 **(c) Please explain how the 10% premium was determined to be appropriate.**

19
20 **Response IR-129:**

21
22 **(a, c) Please refer to the GRA Settlement Agreement provided as NSEB IR-1, Attachment 1.**
23 **Under "PHP Treatment" is the following:**

24
25 **c) The dollar value of the Interruptible credit to be applicable to PHP's**
26 **interruptible load shall be the same as the credit for Large Industrial**
27 **Interruptible customers, plus the value of priority interruption service**
28 **provided, if any. The priority interruptibility service that may be provided**
29 **by PHP is modelled at an additional 10% credit. [emphasis added]**

30
31 **Whether Priority Interruptible Service will be provided by PHP under the PHP ATL Tariff**
32 **and the design and pricing of this service, if provided by PHP, remain to be determined.**

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1 The design and valuation of the service is work that is being undertaken as part of
2 development of the PHP ATL Tariff to be filed with the Board by the end of 2025.

3
4 The Company has proposed a deferral mechanism “PHP Deferral” for, among other
5 elements, differences between the 10 percent additional credit assumed in the GRA and the
6 final approved amount. This is described in section 12.3 of the Application.

7
8 (b) There have been no interruptions of PHP load under tariff interruptibility provisions from
9 2022 to 2025 year-to-date.

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Request IR-130:

Reference: Exhibit N-3 GRA Direct Evidence, Section 12.4 PHP COSS Treatment

On page 80 of the application, NS Power proposed a PHP Deferral account for revenue variances between Board-approval of a tariff for PHP to be determined at a later date and NS Power's assumptions included in the cost of service study used in this application.

(a) Please confirm, or explain otherwise, that the potential variances relate to differences in the assumed and proposed tariffs, and not for revenue variances for other reasons.

(b) Please list and explain the assumptions NS Power has included about the tariff to be approved for PHP in the GRA COSS.

(c) Please explain how revenue variances due to changes in assumptions about PHPs load and load profile would be isolated from changes related to differences in the assumed and approved tariffs.

(d) Please outline the amount, by month, that the actual revenue amounts will be measured against in order to calculate any deferral.

(e) Please provide NS Power's best estimate of the amount deferred by month, if PHP does not take service under an above the line rate in the test years.

Response IR-130:

(a) Given that PHP ATL Tariff development is ongoing with an application anticipated by year end, there may be material differences between what is assumed in the GRA with respect to PHP ATL costs, revenues, and tariff construct and other class rates and what unfolds

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1 once the application is developed and ultimately a Board Decision in the matter is
2 implemented.

3
4 As a cost-of-service utility, where forecast revenues are determined by forecast costs and
5 both are a function of the tariff terms ultimately approved by the Board, it is difficult to
6 confirm with confidence at this point, “that the potential variances relate to differences in
7 the assumed and proposed tariffs, and not for revenue variances for other reasons.” (e.g.
8 Is a change in the tariff arising from a change to the underlying COSS treatment a tariff
9 change?) A determination in this regard will be possible once both proceedings have been
10 completed and Board Decisions on the matters are rendered. The Company can confirm it
11 is not NS Power’s expectation that variances arising from differences in forecast energy or
12 demand volumes compared to actuals would be deferred.

13
14 (b) The assumptions included in the GRA COSS model, as also outlined in NSEB IR 1
15 Attachment 1 under “PHP Treatment,” are as follows:

- 16
17 • PHP’s firm load at 8 MW at the three coincident peaks;
18 • PHP’s firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP
19 metered load at the time of NSP’s 3CP; and
20 • PHP energy will be based on PHP’s forecast usage for the test years, net of the amount
21 forecast to be provided by the Goose Harbour Lake Wind Farm. The same load
22 characteristics are applicable to the base cost of fuel model; specifically, sales of 810
23 GWh in 2026, and in 2027 sales of 810 GWh with 506 GWh forecast to be provided
24 by the Goose Harbour Lake Wind Farm.

25
26 Please also refer to CA IR-1 regarding corrections to the calculation of the Interruptible
27 Credit applicable to PHP.

28
29 (c) As explained in part (b), the Company has the defined assumptions included in the GRA
30 COSS for PHP ATL. Actual fixed cost recovery would be tracked on a monthly basis to be

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1 able to isolate PHP's load and load profile, if this were to be required in any future
2 calculation of the PHP Deferral.

3
4 (d) It is anticipated the basis for the calculation of the PHP Deferral would be the fixed cost
5 recovery included in the GRA for service to PHP. For the annual figures, please refer to
6 OR-01 Attachment 1, tab "PHP," Excel column K. The Company has not developed a
7 monthly forecast for fixed cost recovery from PHP.

8
9 (e) Please refer to part (a). In order to provide a credible monthly forecast of the PHP Deferral,
10 NS Power would need to know the corresponding alternative tariff under which PHP would
11 take service (whether that is above the line or below the line). Given that this remains to
12 be determined, it is not possible to provide a credible estimate of the amount deferred by
13 month, if PHP does not take service under an the above the line rate in accordance with the
14 assumptions included in the GRA.

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1 **Request IR-131:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 2.1 Electricity Rate Impact**

4
5 **Regarding Figure 2-1 of the application, please identify and quantify the specific factors that**
6 **are causing rate increases for Domestic Class customers that are approximately double the**
7 **system average increase.**

8
9 Response IR-131:

10
11 The contributing factors are as follows:

- 12
13 1. **Change in the proposed COS methodology** which, as a result of the extensive COS
14 consultation process and the consensus agreement reached with all customer
15 representatives, classifies more costs to demand-related services than the current
16 methodology. As indicated in response to NSEB IR-127, the Domestic cost of service has
17 increased by about \$26 million or 2.4 percent in 2026 and \$25.3 million or 2.3 percent in
18 2027 compared to the COS results under the current methodology. The above COS results
19 have an effect of an additional 1.5 percent increase to smoothed revenues in both 2026 and
20 2027. The remaining 0.5 percent increase of the 2 percent additional increase is attributed
21 to the two factors stated below.
22
23 2. **Higher increase in the Domestic class contribution to the system peak** than those of
24 other rate classes compared to the COSS results filed in the 2023-2024 GRA. The
25 Domestic class share in the 3CP statistic, as listed in column (11) 3CP % Contribution in
26 Exh 9a Annual, increased by 5 percent from 61.4 percent to 64.2 percent. This results in
27 a higher allocation of demand costs for the Domestic class.
28
29 3. **Shift in the shares of service areas in the total non-fuel system costs** resulting in a lower
30 share of generation (9 percent decrease) and higher share of distribution (37 percent

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1 increase) and retail (39 percent increase). The rate classes which are heavier users of the
2 distribution and retail services, such as the Domestic class, see a relatively higher increase
3 in the allocated total non-fuel system cost as a result of this structural cost change.

4
5 These increases are partially offset by the Domestic Class being set at a lower revenue to
6 cost ratio of 0.97 compared to other rate classes, all of which, except for the Unmetered
7 class, have ratios falling within the 1.04 and 1.05 range.

8
9 Also, please refer to the response to NSEB IR-139 concerned with decreases in non-fuel
10 costs of the classes with demand charges.

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1 **Request IR-132:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13 Rate Design**

4
5 **On page 81 of the application, NS Power notes it is not proposing to introduce new concepts**
6 **or materially modify any of its rate design. Please describe any work NS Power has done to**
7 **develop new or innovative rate designs to leverage more granular data from AMI meters,**
8 **promote efficient use of system resources, or address emerging or anticipated electricity and**
9 **energy market changes due to decarbonization, decentralization of energy resources, or**
10 **other factors.**

11
12 **Response IR-132:**

13
14 In collaboration with stakeholders NS Power is continuing the development of innovative rate
15 structures as part of several initiatives. For a number of these initiatives, Advanced Metering
16 Infrastructure (AMI) has been instrumental in supporting both cost-of-service studies and the
17 ongoing pricing innovation work, in particular through the Time-varying Pricing (TVP) program.
18 The vast majority of customers have an AMI meter and access to the Company's Customer Energy
19 Management System (marketed as MyEnergy Insights, MEI), which arms customers with the tools
20 and information to better understand their energy use and evaluate rate options that may be suitable
21 for their usage patterns.

22
23 In the past year, NS Power has expanded TVP to include the Multi-unit Residential Building
24 (MURB) Time-of-Use Pilot Tariff and has continued its engagement with stakeholders, including
25 Board staff and its consultant (Synapse), to further evaluate and refine the TVP initiative. These
26 efforts continue to focus on broadening enrollment in a measured and deliberate manner and
27 leveraging AMI data to inform future rate design, rather than introducing structural changes at this
28 time. The Company also supports third-party programming through the provision of AMI data to
29 EfficiencyOne (E1) for Demand Side Management activities, and ongoing collaboration on E1's
30 demand response programming.

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1 In addition to mass-market rate design initiatives such as TVP, NS Power continues to administer
2 the Extra Large Industrial Active Demand Control (ELIADC) Tariff as a targeted solution for its
3 largest customer, Port Hawkesbury Paper (PHP). The flexibility of PHP's load, through the
4 provision of Active Demand Control (ADC) service, has delivered quantifiable system benefits.¹
5

6 While, as described on page 81, the Company's proposed 2026-2027 General Rate Application
7 does not propose new rate design concepts or material modifications, NS Power remains
8 committed to developing rate designs that promote efficient use of system resources and respond
9 to evolving market dynamics through engagement with stakeholders on several interrelated matters
10 (e.g. Smart Grid Nova Scotia, Distributed Energy Resources Integration Roadmap).

¹ Please refer to Section 2 and Appendix C of NS Power's Application for Approval of a Third Term for the ELIADC Tariff and, in part, its response to Bates White IR-9 in the same proceeding (M12184).

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Request IR-133:

Reference: Exhibit N-3 GRA Direct Evidence, Section 13 Rate Design

On page 81 of the application, NS Power notes its proposed increases in the customer charges for domestic and small general customers have been capped relative to what they would be if set directly based on changes in the customer-related costs from the 2026-2027 COSS. Please provide a table showing the differences (in \$ and cents/kWh) for the proposed customer charges and energy rates for these classes to the customer charges and energy rates based on the 2026-2027 COSS.

Response IR-133:

Please see below a comparison of requested charges.

Domestic Service Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge (\$/month)	\$20.24	\$29.32	\$9.07	45%
Energy Charge (cents/kWh)	18.349	17.306	(1.043)	-6%
Smoothed Rate				
Customer Charge (\$/month)	\$20.24	\$29.32	\$9.07	45%
Energy Charge (cents/kWh)	18.454	17.411	(1.043)	-6%
2027				
Standard Rate				
Customer Charge (\$/month)	\$21.38	\$30.25	\$8.88	42%
Energy Charge (cents/kWh)	19.335	18.310	(1.025)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$21.38	\$30.25	\$8.88	42%
Energy Charge (cents/kWh)	19.216	18.191	(1.025)	-5%

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1

Small General Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge (\$/month)	\$22.16	\$31.98	\$9.82	44%
Energy Charge (First 200 kWh) (cents/kWh)	18.918	17.840	(1.078)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.089	16.208	(0.881)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$22.16	\$31.98	\$9.82	44%
Energy Charge (First 200 kWh) (cents/kWh)	19.053	17.975	(1.078)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.224	16.343	(0.881)	-5%
2027				
Standard Rate				
Customer Charge (\$/month)	\$23.07	\$33.28	\$10.21	44%
Energy Charge (First 200 kWh) (cents/kWh)	20.100	18.984	(1.116)	-6%
Energy Charge (Additional kWh) (cents/kWh)	18.074	17.163	(0.911)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$23.07	\$33.28	\$10.21	44%
Energy Charge (First 200 kWh) (cents/kWh)	19.951	18.835	(1.116)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.925	17.014	(0.911)	-5%

2

3

4 NS Power notes that while the customer charge has not been set based on the amounts shown in
5 customer-related costs from the COSS, any costs that are not recovered through the customer
6 charge would be recovered through an increase in the energy charge.

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1 **Request IR-134:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13 Rate Design**

4
5 **On page 81, NS Power stated:**

6
7 **If the customer charges were to be set directly based on changes in the**
8 **customer-related costs from the 2026-2027 COSS, they would show**
9 **about a 50 percent increase in 2026 followed by a minor a single digit**
10 **increase in 2027.**

11
12 **(a) Please explain the main factors contributing to the 50% increase.**

13
14 **(b) Please state the single digit increase in 2027 and the main contributing factors.**

15
16 **Response IR-134:**

17
18 **(a)** As part of the 2023/2024 GRA Application NS Power proposed to have the customer
19 charge set based on the COSS customer costs, which would have resulted in the customer
20 charge going from \$10.83 to \$21.99 for the Domestic Class. However, as part of the
21 Settlement Agreement the customer charge was set at 75 percent of the proposed increase,
22 resulting in a \$19.17 customer charge. As a result, a portion of the increase is a result of
23 the current customer charge being set below COSS results in prior GRAs.

24
25 Other changes contributing to the increase include the revenue requirement changes for the
26 2026 test year, including a higher level of investments in areas that drive customer costs,
27 such as smart grid enhancements, AMI and customer information systems.¹ Also, the COS
28 changes have resulted in more costs being directly attributed to the appropriate functional

¹ Please refer to section 1.4 Reliability and System Strength

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1 area for general plant, such as customer function, which were assigned across all functional
2 areas in previous studies.

3
4 (b) As described in part (a), the increase in 2026 drives a larger one-time increases, but there
5 is only a need for a smaller increase (approximately 3 percent for Domestic and
6 approximately 4 percent for Small General) between 2026 and 2027. This change is mainly
7 driven by revenue requirement changes in the customer cost area between those years.

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1 **Request IR-135:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13 Rate Design**

4
5 **On page 82 of the application, NS Power notes that it has updated the interruptible credit**
6 **for the Large Industrial Interruptible Rider. Please compare the avoided cost of a**
7 **combustion turbine to the avoided cost of capacity used for DSM programs.**

8
9 Response IR-135:

10
11 The interruptible credit is \$160 kW/year and the most recently calculated levelized avoided costs
12 of capacity is \$140 kW/year. Differences between the values are attributed to the different
13 methodologies used to calculate the two values.

14
15 Consistent with the established methodology used in prior General Rate Applications, the proposed
16 updates to the interruptible credit for the Large Industrial Interruptible Rider (LIIR) reflect current
17 cost inputs, specifically updates to the avoided cost of a combustion turbine (CT), and do not
18 represent a change in the underlying approach or methodology for the LIIR credit. Support for the
19 updated credit values is provided in SR-01 Attachment 4.

20
21 For comparison purposes, the ‘avoided cost of a CT’ reflects the avoidance, or deferral, of future
22 generation capacity costs that NS Power would otherwise need to incur to serve the interruptible
23 load (if that load were firm, rather than interruptible). The interruptible credit is designed to mimic
24 the operation of a combustion turbine operating as a peaking facility. As such participants are
25 required to interrupt their load within 10 minutes of receiving a request from the System Operator,
26 similar to the start-up time of a CT, and interruptions can be up to 16 hours a day, five days a week,
27 to a maximum of 30 percent of hours per month and 15 percent of hours in a year. For these
28 reasons, this remains the appropriate avoided cost basis for the valuation of the interruptible service
29 customer credit.

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1 In contrast, the ‘avoided cost of capacity’ is part of a series of avoided costs¹ used to support
2 Demand Side Management (DSM) programming. The foundation of the avoided cost modelling
3 exercise is the most recent Integrated Resource Plan (IRP) model. The avoided cost of capacity
4 reflects broader planning assumptions and is intended to capture the incremental value of demand
5 savings from efficiency programming. Where the LIIR credit basis considers the avoided cost of
6 added CT generation in consideration of the interruptible (i.e. non-firm) load subscribed, DSM
7 avoided capacity costs consider the ‘basket’ of DSM measures and programs which have
8 properties that are more variable than an interruptible industrial load. These are assessed using a
9 ‘with’ and ‘without’ DSM run through PLEXOS, as part of broader system planning efforts.
10 Supply side costs in the avoided cost of capacity analysis include costs from other resources which
11 contribute firm capacity to the power system in addition to combustion turbines. Further, the
12 avoided costs of DSM series are used in the assessment of the overall cost-effectiveness of DSM
13 measures, programs, and portfolios.

¹ The most recent avoided cost of DSM series includes the avoided costs of energy, avoided costs of capacity, avoided costs of transmission and distribution, and (as developed by EfficiencyOne) the avoided cost of carbon.

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Request IR-136:

Reference: Exhibit N-4, PR-01 Attachment 01D, Domestic Service Time-of-Day Tariff

- (a) Please provide a copy of the charges as originally approved for this tariff and explain the rationale used to set the peak, shoulder, and off-peak rates.
- (b) Please provide the value of the shoulder and off-peak rates as a percentage of the peak rate for the originally approved tariff and for the proposed 2026 and 2027 tariffs.
- (c) If the percentages have changed since originally approved, please explain how those amendments were justified.

Response IR-136:

- (a) The Domestic Time-of-Day (TOD) Tariff came into effect in 1997, following the Board's approval of the rate as part of the 1996 General Rate Application.¹ The applicable page of the Board Decision, setting out these rates, is provided as Attachment 1.

The Domestic TOD rate was approved as part of the Company's 1996 Rate Application, requiring electric thermal storage (ETS) systems as a tool to retain electric heating customers to the benefit of all customers. The structure of the rate (peak to shoulder to off-peak) was reflective of historical embedded cost principles and system usage patterns and did not explicitly set ratios for the respective time periods. On March 4, 1996, the Board approved the Domestic TOD rate, establishing approximate ratios of 2:1 (peak to shoulder) and 4:1 (peak to off-peak).

- (b) Please refer to the table below.

¹ M06131 – Board Decision, 22206, page 66 (PDF page 70). March 4, 1996.

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Period	1996 Approved TOD	2026 Proposed TOD	2027 Proposed TOD
Winter (December, January, and February – non-holiday weekdays)			
Mid-peak/Shoulder ² (as percent of peak rate)	50	80	79
Off-peak ³ (as percent of peak rate)	25	47	46
Non-winter (March to November)			
Off-peak ⁴ (as percent of peak rate)	50	59	58

(c) Prices applicable to the TOD Tariff have changed over the years as GRAs have occurred and the cost composition of the Domestic TOD class has changed. The Company has not compiled a comprehensive list of how those amendments were justified over the 30 years since this Tariff was introduced.

A significant shift in the TOD energy charge ratios occurred following the Board Order of December 1998 implementing the proposed modification by NS Power to reduce the winter on-peak energy charge from 16.70 cents per kWh to 12.00 cents per kWh effective December 11, 1998.⁵ The proposed modification was in response to TOD customer concerns regarding the on-peak energy charge; having been originally set four times higher than the off-peak charge, it was too high to allow customers achieve anticipated bill savings to offset the costs of their investments in the ETS units required for the Tariff.

Another reason for changes in the TOD energy charge ratios has been the higher pace of increases in the base cost of fuel component of the energy charges, which are non-time

² Winter mid-peak/shoulder is applicable December, January, and February on non-holiday weekends between 12 PM and 4 PM.

³ Winter off-peak is applicable December, January, and February on non-holiday weekends between 11 PM and 7 AM.

⁴ Non-winter off-peak is applicable March to November between 11 PM and 7 AM.

⁵ Letter from Robert Boutilier, Manager Rates and Regulations, to Mr. Morash Re. Approval of Modification to the On-Peak Energy Rate and Availability Clause in the Domestic Service Time-of-Day Rate, dated December 21, 1998.

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1 differentiated, than the time-differentiated non-fuel base cost components. As the relative
2 share of the non-time differentiated fuel cost-based components goes up, the charge ratios
3 get eroded.

it is recognized that at some time in the future, direct load control by the utility may be appropriate, it is considered that the majority of the savings can be achieved through TOD rates.

The Board approves specific TOD rates for ETS customers within the Domestic class as outlined, effective immediately:

During the months of December, January and February

Period	Rate (cents per kW.h)
7:00 am to 12:00 noon	16.70
12:00 noon to 4:00 pm	8.35
4:00 pm to 11:00 pm	16.70
11:00 pm to 7:00 am	4.175

These rates apply weekdays (Monday to Friday inclusive), excluding statutory holidays. For holidays and week ends, all consumption will be billed at the rate of 4.175 cents per kW.h.

For the remaining months of the year March to November

Period	Rate (cents per kW.h)
7:00 am to 11:00 pm	8.35
11:00 pm to 7:00 am	4.175

The above rates apply weekdays (Monday through Friday) except for statutory holidays.

For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 4.175 cents per kW.h.

For calendar year 1996, the availability of these rates will be restricted to those customers employing ETS equipment obtained from the Applicant. The Board will review the results of this program prior to January 1997 and determine if these restrictions should be continued or if the availability of these rates should be extended to all customers in the

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1 **Request IR-137:**

2
3 **Reference: OATT Updates SR-01 Attachment 1e**

4
5 **On page 32 of 42, NS Power stated:**

6
7 **However, as part of developing this consensus GRA, it was agreed that**
8 **for the 2026-2027 test periods the costing approach will utilize 50**
9 **percent of the estimated average hourly demand of LIIR interruptible**
10 **load as 10-minute operating reserve on a day ahead basis. With the**
11 **average hourly interruptible load under the Large Industrial Rate**
12 **class, estimated to be 70 MWs, the required 10 minute Supplemental**
13 **capacity of 136 MWs is reduced by 35 MWs to 101 MWs for the pricing**
14 **purposes of this service in tab “Anc Serv – Fig 6-8” of SR-01**
15 **attachments 11 and 13.**

16
17 **(a) Please explain the rationale for selecting 50% as the appropriate value for the**
18 **costing amendment.**

19
20 **(b) What is the dollar impact resulting from this costing amendment?**

21
22 **Response IR-137:**

23
24 (a) The issue of alternative treatment of interruptible loads was raised in M10431. NS Power
25 was provided direction by the Board to explore options in the alternative treatment of
26 interruptible loads and file its analysis of cost implications associated with alternative
27 treatment of interruptible loads.¹ NS Power provided its view of this issue within SR-01
28 Attachment 1e and is summarized on page 31 and 32. However, as this item remains a
29 concern of the MEUs it was determined through consensus discussions that for the purposes
30 of the 2026 and 2027 test years, the 50 percent figure would be applied.

¹ M10431 Board Decision February 2, 2023, section 7.13.6.1.

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(b) Please refer to the following figure; only OATT Schedules 5 and 6 are impacted by this change.

Description	OATT Revenue (as proposed in 2026-2027 GRA)		OATT Revenue (fully cost based)		Dollar Impact	
	2026	2027	2026	2027	2026	2027
Schedule 5 and 6 Operating Reserve	\$87,739	\$91,499	\$104,364	\$109,160	-\$16,625	-\$17,662

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Request IR-138:

Reference: OATT Updates SR-01 Attachment 1e

On page 42 of 42, NS Power stated:

... NS Power conducted an analysis of historical day-ahead dispatch plans for the years 2021 to 2023. On average, the Combustion Turbines (CTs) were dispatched to fulfill approximately 35 percent of the 30-Minute Supplemental Reserve requirement each hour.

Given this change, NS Power has adjusted the cost allocation in this GRA application for 30-Minute Supplemental Reserve to account for the contribution that CTs make in the provision of 30-Minute reserve, as per this analysis.

(a) What is the dollar impact resulting from this adjusted cost allocation?

Response IR-138:

(a) Please refer to the following figure; only OATT Schedules 5 and 6 are impacted by this change.

	OATT Revenue (as proposed in 2026-2027 GRA)		OATT Revenue (fully cost based)		Dollar Impact	
	2026	2027	2026	2027	2026	2027
Schedule 5 and 6 Operating Reserve	\$87,739	\$91,499	\$89,172	\$92,820	-\$1,433	-\$1,322

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1 **Request IR-139:**

2
3 **Reference: Exhibit N-3, GRA Direct Evidence, Page 18**

4
5 **Figure 2-2 provides the proposed rate summary.**

6
7 **(a) Please explain the factors which have caused the 2026 demand charge to**
8 **materially decrease for the General Tariff, Large General Tariff, the Industrial**
9 **Tariffs and the Municipal Tariff.**

10
11 **(b) If the changes to the demand charge flow from the revised cost of service study,**
12 **please explain the factors that contributed to the changes across these customer**
13 **classes.**

14
15 **Response IR-139:**

16
17 (a) Decreases in the 2026 demand charges, also accompanied by equivalent decreases in the
18 non-fuel components of the base cost energy charges of these rate classes, are due to the
19 shift in responsibilities of these classes for their non-fuel costs as a result of the following:

- 20
21
 - Decreases in the relative share of demand-related costs of these classes due to
22 a parallel increase in the responsibility for these costs by the Domestic class
23 between the 2023 COSS and 2026 COSS and inclusion of PHP as an above-
24 the-line rate class. The Domestic class share in the 3CP statistic, as listed in
25 column (11) 3CP % Contribution in Exh 9a Annual, went up by 5 percent from
26 61.4 percent to 64.2 percent. Those rate classes with demand charges went
27 down. For example, the share of the Large Industrial (LI) in the 3CP metric
28 went down by 26 percent from 4.9 percent to 3.6 percent and that of the Large
29 General (LG) went down by 22 percent from 2.6 percent to 2.0 percent.

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- Change in classification of generation costs under the proposed COSS methodology where relatively more of these costs are now classified to demand than what is the case under the current COS methodology. This has an effect of lessening the responsibility for these costs by higher load factor rate classes which happen to be rate classes with demand charges.
- Change in classification of transmission costs under the proposed COSS methodology where all these costs are now classified to demand. Similar to the case above, this has an effect of lessening the responsibility for these costs by higher load factor rate classes.
- Shift in the cost shares of service areas in the total non-fuel system costs resulting in a lower share of generation and higher shares of distribution and retail. The rate classes, which are smaller users of the distribution services, such as the LI, LG and Medium Industrial (MI) see a favourable changes in their relative shares of the system non-fuel costs.

(b) Please see the response to (a) above.

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1 **Request IR-140:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13.6, Storm Cost Recovery Rider**
4 **(SCRR)**

5
6 **(a) Please explain why the initial term of the SCRR was not sufficient to reach**
7 **conclusions or recommendations, such that there is now a need to extend the pilot for**
8 **two more years.**

9
10 **(b) What is the proposition intended to be tested during the extended pilot phase?**

11
12 **(c) How will success of the pilot be determined?**

13
14 **(d) Please identify all metrics that will be used to assess the success or failure of the pilot**
15 **extension, and any thresholds or benchmarks hoped to be achieved.**

16
17 **Response IR-140:**

18
19 **(a) Please see the response to NSEB IR-1.**

20
21 **(b) NS Power believes the proposition to be tested is whether the SCRR will continue to help**
22 **ensure that customers pay only those actual Level 3 and 4 storm restoration costs that are**
23 **incurred.**

24
25 **(c) Please see the response to (b), above.**

26
27 **(d) Please see the response to (b), above.**

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1 **Request IR-141:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13.6, Storm Cost Recovery Rider**
4 **(SCRR)**

5
6 **On pages 84-85 of the application, NS Power outlines the key elements of a “permanent”**
7 **SCRR.**

8
9 **(a) Please confirm or explain otherwise, that Board is not being asked to approve a**
10 **permanent SCRR in this proceeding, only a two-year extension of the existing pilot,**
11 **modified to be more symmetrical.**

12
13 **(b) Please confirm that any underspend of Level 3 and 4 storm compared to the amount**
14 **in base rates in a year is automatically credited to customers each year.**

15
16 **(c) Please confirm, or explain otherwise, that if there is an overspend of Level 3 and 4**
17 **storm costs compared to the amount in base rates in a year, NS Power must apply by**
18 **April 30 to recover the shortfall (through a combination of rider adjustments or**
19 **drawing down the SCRR Customer Account), and if no application is made, recovery**
20 **of the overspend in that year is foregone.**

21
22 **(d) Given that the application is for a two-year extension of the pilot, please confirm or**
23 **explain otherwise, that if the pilot ends, NS Power will return any underspend**
24 **balances in the SCRR Customer Account to customers at that time, rather than after**
25 **“three consecutive years”.**

26
27 **(e) Please confirm, or explain otherwise, that the cost of financing the deferral or return**
28 **is subject to s. 64AB of the *Public Utilities Act*.**

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1 Response IR-141:
2

3 (a) Confirmed. The Board is being asked to approve the continuation of the SCRR on a pilot
4 basis for the years 2026-2027, but modified on a symmetrical basis.
5

6 (b) Confirmed. Such amounts would be credited to customers each year in the SCRR
7 Customer Account or by way of an SCRR, depending on whether the \$2.5 million or three
8 consecutive year thresholds have been triggered.
9

10 (c) Confirmed.
11

12 (d) Confirmed, unless the use of the SCRR has been extended or a Board order directs
13 otherwise.
14

15 (e) Confirmed.

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1 **Request IR-142:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13.6, Storm Cost Recovery Rider**
4 **(SCRR)**

5
6 **On page 84, NS Power is “...asking that the SCRR be in place on a symmetrical basis for**
7 **2026 and 2027, which would allow recovery of Level 3 and 4 storm OM&G restoration costs**
8 **above those included in revenue requirement or for any underspend of such costs to be**
9 **returned to customers, in each year.” [emphasis added] However, the bulleted key elements**
10 **of the SCRR proposes accumulating any Level 3 and 4 underspend for three consecutive**
11 **years or until a threshold amount of \$2.5 million is reached. If actual Level 3 and 4 storm**
12 **costs exceed the amount in base rates, NS Power intends to request approval to recover the**
13 **shortfall effective January 1 of the following year.**

14
15 **(a) Please explain how that proposal is symmetrical for both NS Power and its**
16 **ratepayers.**

17
18 **(b) Please explain why any storm cost underspend should not be returned to ratepayers**
19 **effective January 1 of the following year.**

20
21 **(c) Please update Figure 13-2 to include each of 2020 to 2025.**

22
23 **Response IR-142:**

24
25 **(a) The proposal is symmetrical because it returns any underspend to customers and provides**
26 **NS Power with the opportunity to collect any overspend. The symmetrical nature of the**
27 **proposal is not changed by the fact that the proposed terms of the SCRR include any Level**
28 **3 and 4 underspend being accumulated for three consecutive years or until a threshold**
29 **amount of \$2.5 million is reached.**

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(b) Any storm underspend could be returned to customers effective January 1 of the following year; however, if the SCRR was structured in that manner it could result in an SCRR application every year, regardless of its materiality. Structuring the SCRR in the manner proposed provides NS Power with the election to make an SCRR application, but such an election is not practical when dealing with multiple customer groups, so the three consecutive years or a \$2.5 million threshold was arrived at by the parties as a way to help ensure that SCRR applications are only happening when there is a material amount to be recovered or whether a material amount of time has passed.

(c) Please see the table below. Prior to 2023, NS Power did not include separate amounts for Level 1 & 2 and Level 3 & 4 storm restoration expense in revenue requirement.

Year	Level 1 & 2 (\$ million)	Level 3 & 4 (\$ million)	Total Storm OM&G in Revenue Requirement
2020	N/A	N/A	10.8
2021	N/A	N/A	10.8
2022	N/A	N/A	10.8
2023	7.2	10.2	17.3
2024	7.3	10.4	17.7
2025	7.3	10.4	17.7
2026	9.6	10.1	19.7
2027	9.8	10.3	20.1

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1 **Request IR-143:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13.5 DSM Rider.**

4
5 **On page 82, NS Power stated:**

6
7 **NS Power is not proposing changes to the DSM rider amounts for 2026**
8 **or 2027. However, NS Power is proposing changes to how the Balance**
9 **Adjustment (BA) is calculated.**

10
11 **(a) Please provide an illustrative example of how the proposed BA will be calculated.**

12
13 **(b) Please provide the justification for the proposed change to the Balance Adjustment**
14 **component of the DSM rider.**

15
16 **(c) Please explain whether the 2027 DSM expense of \$63.8 million shown in Figure 11-1**
17 **was confirmed by EOne based on their anticipated portfolio. If not, please explain**
18 **why not.**

19
20 **(d) Please explain whether NS Power has requested EOne to include any specific DSM**
21 **initiatives in its 2026 or 2027 portfolio. If so, please identify those initiatives and the**
22 **associated expenditures included in NS Power's revenue requirement. If not, please**
23 **explain why not.**

24
25 **Response IR-143:**

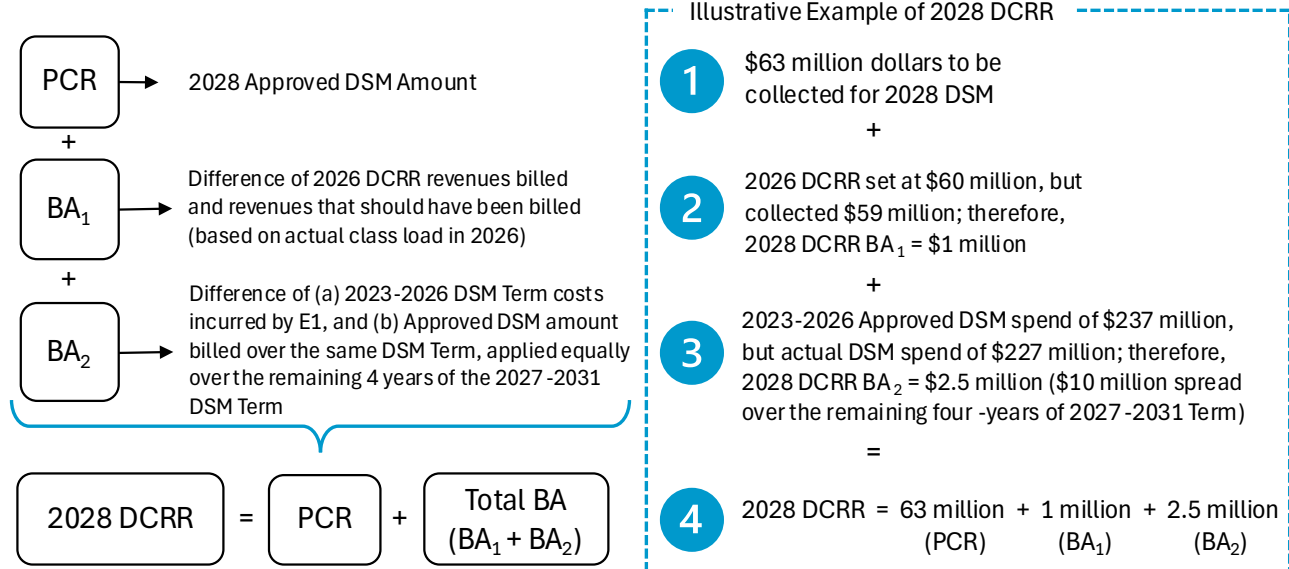
26
27 **(a) Please refer to the figure below. Note, values provided in the example are for illustrative**
28 **purposes only. In the figure, DCRR stands for Demand Side Management Cost Recovery**
29 **Rider, PCR stands for Program Cost Recovery, and BA stands for Balance Adjustment.**

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Proposed DCRR Framework

If approved, the proposed DCRR framework would be in effect during the 2027-2031 DSM Term.

For example, the 2028 DCRR would include:



(b) The proposed DCRR framework adds a BA₂ component to the BA to reconcile, by rate class, the differences between E1's approved and actual DSM expenditures following the completion of the prior DSM Plan Term. Under the current DCRR framework, these variances would be trued up and recovered over one or two years.

In light of the flexibility for E1 to re-allocate DSM expenditures between rate classes within a DSM Term and recent legislative changes, which prescribe five-year DSM Terms beginning with the 2027-2031 DSM Plan, the end-of-term true-up under the current framework may result in large variances to be collected or refunded through the DCRR. The proposed BA₂ allocates these variances evenly over a four-year recovery period, beginning in year two of the following Term,¹ reducing the volatility in rates driven by E1 expenditure decisions.

¹ For example, variances following the end of the 2023-2026 DSM Term would be calculated in 2028 and allocated across the remaining four-years of the 2027-2031 DSM Term (i.e. 2028, 2029, 2030, and 2031).

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1 The consensus GRA change to the DCRR framework:

- 2 • Aligns the Rider cost recovery processes resulting in a more transparent and
3 complete Rider framework;²
- 4 • Extends the recovery/refund period for end-of-Term variances which is expected to
5 reduce the volatility in rate impacts of DSM expenditure reallocations and better
6 reflect the multi-year nature of DSM planning and spending; and
- 7 • Maintains the cost causation principle of the DCRR by continuing to collect, or
8 return, actual DSM expenditures in a way that reflects which rate classes those costs
9 were actually allocated to without potentially abrupt adjustments following the end
10 of a DSM Term.

11
12 (c) The DSM expense provided in the forecast revenue requirement breakdown (Figure 11-1)
13 was not confirmed by E1 or based on an anticipated portfolio. As described on page 82 of
14 the Direct Evidence, legislation introduced in 2025 extended the existing DSM Supply
15 Agreement between E1 and NS Power by one year and set the 2026 DSM amount
16 recoverable at \$63.75 million. E1's proposed 2027-2031 DSM Application was not filed at
17 the time of 2026-2027 GRA development; therefore, the Company set the 2027 DSM
18 expense at \$63.75 million (or \$63.8 million rounded) for consistency with the legislated
19 2026 DSM expense. For the purposes of this Application, NS Power has assumed the
20 continuation of the DCRR amounts for 2026 or 2027. NS Power filed its DCRR
21 Application for recovery of the 2026 DSM expenses, using the current DCRR framework,
22 on October 22, 2025 (M12521).

23
24 (d) NS Power is an active participant in the DSM Advisory Group (DSMAG), which E1
25 regularly engages in DSM Plan development processes. As part of its participation in the
26 review of DSM Plan development, NS Power, like other DSMAG members, may provide
27 input or feedback throughout the process and leading into DSM Plan Applications.
28 However, the Company has not requested or included specific DSM initiatives and

² BA₁ reconciles volume-based variances and BA₂ adds a DSM expenditures-based reconciliation mechanism.

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1 associated expenditures in its revenue requirement. As provided in part (c), NS Power's
2 DSM expense in the forecast revenue requirement for this Application is assumed at the
3 2026 legislated amount for both 2026 and 2027, and does not include specific DSM
4 activities.

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1 **Request IR-144:**

2
3 **Reference: Exhibit N-3 GRA Direct Evidence, Section 13.7, AMI Opt-Out Fee**

4
5 **(a) Please describe any limits NS Power currently faces in reading AMI meters over**
6 **the air as a result of its cybersecurity breach.**

7
8 **(b) Please describe all arrangements NS Power continues to make to manually read**
9 **AMI meters due to the cybersecurity breach.**

10
11 **(c) If NS Power is currently manually reading AMI meters due to the cybersecurity**
12 **breach, please provide all available information that identifies when the need to**
13 **manually read AMI meters will end.**

14
15 **(d) Please confirm, or explain otherwise, that to the extent that NS Power needs to**
16 **manually read AMI meters in 2026 and 2027, the incremental cost for manually**
17 **reading opt-out customers presented in NS Power's application for the test years**
18 **is no longer accurate since opt-out customer meters can easily be read at the same**
19 **time their non-opt out neighbours' meters are being read.**

20
21 **Response IR-144:**

22
23 (a) Over-the-air billing requires remote retrieval of the data from customer AMI meters. While
24 restoration of the systems required to retrieve this data is underway, the Company cannot
25 read AMI meters over the air. Please also refer to the details provided in the 2025/26 Time-
26 varying Pricing Proposed Approach (M12499) and in NS Power's Cybersecurity Incident
27 Monthly Update 2 and 3 (M12273).

28
29 (b) NS Power has allocated internal resources and hired contractor meter readers to conduct
30 manual reads of customer meters. Business processes and system integrations have been

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1 developed to support manual meter reading. Manual meter reading continues to be done
2 in alignment with the normal meter reading schedule per bill cycle.

3
4 (c) As provided in the Company’s Cybersecurity Incident Monthly Update 2 (M12273),
5 “Online account access and billing capabilities have been restored, while work has
6 commenced to reinstate automated meter data integration. NS Power expects customer
7 billing and engagement processes to return to business as usual in early 2026, with interim
8 measures maintained until that time to ensure continuity for customers.”¹

9
10 (d) Not confirmed. NS Power does not expect to require manual meter reading into 2027 and,
11 as provided in part (c), AMI billing processes are expected to be restored early in 2026.
12 Any residual manual meter reading will not materially affect the costs associated with
13 providing non-standard meter service to opt-out customers. Please also refer to NSEB IR
14 146.

¹ M12273 – NS Power, Cybersecurity Incident Monthly Update 2, page 3. October 1, 2025.

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Request IR-145:

Reference: Exhibit N-8, Appendix 13A, page 6 of 14.

NS Power stated that it has refreshed its jurisdictional review using the same utilities included in its 2017 summary. Appendix 13B lists four Canadian utilities and six USA utilities.

(a) Has NS Power reviewed opt-out policies for any electrical utilities other than the 10 utilities listed in Appendix 13B? If so, please identify those utilities.

(b) Based on its knowledge or research of other jurisdictions, please identify any electrical utilities that do not charge a meter read opt-out fee.

Response IR-145:

(a-b) No. Given the Company's 2023-2024 GRA (M10431) had stakeholder support for the AMI opt-out fee through the settlement agreement, the Company prioritized addressing the concerns expressed in the Board's M10431 Decision on the opt-out rate.

As part of the M10431 Decision, the Board directed NS Power to explore reasonable options to minimize or eliminate the proposed opt-out fee, including a jurisdictional review of non-standard meter service charges. Consistent with that direction, NS Power refreshed the jurisdictional review in its 2017 AMI Application. NS Power did not expand the review beyond the ten utilities listed in Appendix 13B; the focus was to maintain comparability with the 2017 jurisdictional review of the same set of utilities.

As outlined in Appendix 13A, NS Power has addressed the Board's concerns, as described in its M10431 Decision, by:

- Exploring options to minimize or eliminate the need for an opt-out fee;

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- Conducting an economic comparison of in-house vs. outsourced meter reading;
- Evaluating flexible customer options, including reduced read frequency;
- Tracking and reporting actual opt-out costs annually; and
- Developing a fee based solely on the incremental costs of providing non-standard meter service.

Please also refer to NSEB IR 146.

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1 **Request IR-146:**

2
3 **Reference: Exhibit N-8, Appendix 13A, page 7 of 14.**

4
5 **NS Power stated that approximately 41.5% of the total AMI project costs were for the AMI**
6 **meters themselves, and that most non-standard meters are also AMI meters, so all customers**
7 **should contribute to that capital investment.**

8
9 **(a) What portion of the remaining 58.5% of total AMI project costs are associated with**
10 **components (e.g., labour, material, equipment, communication networks, software,**
11 **training, etc.) that are not directly required by opt-out customers?**

12
13 **Response IR-146:**

14
15 (a) The AMI project was a comprehensive capital initiative to roll-out interval meters to more
16 than 500,000 customers across the province. The project was designed to enable system-
17 wide benefits that extend to all customers, including those that have now opted out of
18 standard meter service. Attempts to parse out AMI project costs (meter-specific or
19 otherwise) overlooks the indirect benefits that opt-out customers continue to receive, such
20 as enhanced outage detection and response, improved reliability, and operational
21 efficiency. These benefits are enabled through the collective contribution of interval meter
22 data from standard meter service customers – a contribution that opt-out customers do not
23 make. These forgone contributions limit the Company's ability to fully leverage AMI
24 capabilities and may further increase costs borne by the broader customer base.

25
26 NS Power has proposed an AMI opt-out fee that reflects the incremental costs of providing
27 non-standard meter service and is informed by five years of tracking and reporting on these
28 costs through its AMI Opt-out Costs Report (Appendix 13C).¹ The AMI opt-out fee ensures

¹ In its M08349 Decision dated December 6, 2018, the Board directed the Company to "use monthly fees of \$4 for customers currently on a bi-monthly reading schedule and \$22 for customers currently on a monthly reading

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1 that only those customers who opt-out of standard meter service bear the incremental costs
2 they are imposing on the system associated with their chosen meter service. As a result, the
3 premise of isolating portions of AMI project costs as “not directly required” based on the
4 type of meter service customers take is fundamentally flawed. Please also refer to the
5 Company’s response in NSEB IR 145.

schedule, respectively, as the approximate values in its communication to customers regarding the opt-out option, with the understanding that those numbers are rough estimates which remain to be verified during the next General Rate Application.” The 2023-2024 GRA was the next rate application, and NS Power’s proposed AMI opt-out fee received stakeholder support through the Settlement Agreement in that proceeding.

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Request IR-147:

Regulation 5.1 provides customers with the ability to record their meter readings and submit those to NS Power for billing purposes. That Regulation also states that an actual reading must be taken by NS Power at least once within a 12-month period for meters which are read bi-monthly and once within a 6-month period for meters which are read monthly.

(a) Please confirm NS Power’s understanding that Regulation 5.1 is a Board-approved regulation and the Board has the authority to make changes to that Regulation.

(b) Please identify any legal or other regulatory requirements which stipulate that the Company must perform those 12-month or 6-month meter readings.

Response IR-147:

(a) Confirmed.

(b) The Company is not aware of any additional legal or regulatory requirements that specifically stipulate 6- or 12-month actual meter reading requirements.

During NS Power’s review of the proposed Regulation 5.1 amendments, in response to this information request, the Company identified additional revisions to be incorporated in the proposed redline. NS Power’s initial redline unintentionally omitted the references to estimated meter reading under the ‘Standard Meter Service’ section. Estimated meter readings with Advanced Metering Infrastructure (AMI) service could occur if data is temporarily interrupted or delayed at the time of scheduled billing. The proposed revisions to Regulation 5.1 should instead read as follows:¹

¹ For clarity, the blue underline revisions are those proposed by the Company in the original submission filed September 17, 2025; red underline revisions are the additional clarifications proposed in response to this information request, and in Attachment 1.

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1 STANDARD METER SERVICE

2
3 Advanced Metering Infrastructure (AMI) service (also referred to as “smart
4 meters”) is the standard for NS Power customers. AMI data shall be used
5 to determine customer billing.

6
7 Estimated Meter Reading

8 If the Company is unable to obtain a meter reading due to circumstances
9 beyond its control, then the amount of power and energy used by the
10 Customer shall be estimated by the Company using the best available data.

11
12 In the event that actual meter readings are obtained subsequent to estimated
13 readings, the Company shall make the necessary adjustments.

14
15 Notwithstanding the foregoing, for standard meter service, an actual manual
16 reading must be taken by the Company at least once within a twelve-month
17 period for a Domestic or Small General class Customer, and once within a
18 six-month period for meters which are read monthly.

19
20 Should the Board approve the proposed revisions to Regulation 5.1, the Company would
21 provide the revisions included above, to incorporate the same Estimated Meter Reads
22 language proposed under the ‘Non-Standard Meter Service’ section, in a compliance filing.

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1 **Request IR-148:**

2
3 **Reference: Exhibit N-8, Appendix 13A, page 8 of 14**

4
5 **NS Power stated that customer-submitted meter readings can result in intentional**
6 **misreporting and that it could be challenging to accurately capture consumption readings**
7 **on the AMI digital meters. It also stated that 177 customer accounts submitted a postcard or**
8 **photo meter reading in 2024.**

9
10 **(a) Does reference to “customer accounts” also indicate that only one photo or**
11 **postcard meter reading was submitted by each of the 177 accounts?**

12
13 **(b) Please state how many of those customer-submitted photo or postcard readings**
14 **were determined to be incorrect.**

15
16 **(c) Please indicate whether short video or other instructional material is, or can be,**
17 **available to assist customers to correctly record their AMI digital meter readings.**

18
19 **(d) Please confirm whether NS Power has the ability to identify anomalies which**
20 **might indicate incorrect meter readings (whether intentional or not) and takes**
21 **steps to rectify those occurrences.**

22
23 **(e) Please state the number of such events in each year since AMI approval in 2018.**

24
25 **Response IR-148:**

26
27 **(a) Not necessarily. At least one photo or postcard meter reading was submitted by 177 distinct**
28 **customer accounts in 2024; however, there was an average of two submissions per**
29 **customer. This is slightly down from 2023, as shown in the table below:**

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Year	Number of Distinct Customer Accounts		Total
	Postcard Meter Submission	Photo Meter Submission	
2023	18	169	187
2024	16	161	177

Of note, the photo meter submission method includes customer-submitted reads for NS Power to review and, if applicable, correct a billed meter read.

- (b) This metric is not tracked. Customer-submitted photo or postcard readings are currently used for billing with minimal scrutiny. Meter readings are cumulative. True readings lead to the recovery of any understated usage or underbilled amounts. The risk of prolonged incorrect billing is mitigated with the current provision under Regulation 5.1, which provides:

[...] an actual reading must be taken by the Company at least once within a twelve-month period for meters which are read bi-monthly and once within a six-month period for meters which are read monthly.

- (c) Instructional material is currently available on the Company’s website ([FAQ| Nova Scotia Power](#)). NS Power plans to update its current self-report online forms which augment the existing content. This is part of the MyAccount restoration work being conducted in response to the cybersecurity incident and is expected to be completed in 2026.

- (d) NS Power has the ability to identify customer bills which exceed a predefined dollar-value threshold set for any particular rate code. If the customer’s bill exceeds this threshold, the account is identified with a “high” billing exception and the account is reviewed. These exceptions do not necessarily indicate incorrect meter readings; rather, they reflect bills that are unusually high compared with the set threshold. Factors such as changes in consumption patterns (e.g. migrating from oil to electric heating) or adjustments to the

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1 predefined threshold influence the number of flagged accounts. Please refer to the table in
2 part (e) for the annual counts of the “high” billing exceptions.

- 3
4 (e) Please refer to the table below which provides a count of customer bills flagged with a
5 “high” billing exception since the approval of the AMI Project in 2018. These counts, as
6 described in part (d), represent bills that exceeded the dollar-value threshold for their rate
7 code and were reviewed, and is not a count of confirmed incorrect meter reads.

8

Year	Count of Bills with “High” Billing Exception
2018	5,008
2019	6,271
2020	5,556
2021	4,306
2022	5,620
2023	3,239
2024	7,943
2025 YTD	6,035

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1 **Request IR-149:**

2
3 **Reference: Exhibit N-8, Appendix 13C**

4
5 **NS Power stated:**

6
7 **As of April 1, 2025, approximately 97 percent of AMI meters have been**
8 **migrated to fully automated meter reading and billing using AMI**
9 **meter data, known as Over-the-Air (OTA) billing. All meters that are**
10 **able to be migrated to OTA billing have been successfully transitioned.**

11
12 **(a) What is the status of the remaining 3% of AMI meters?**

13
14 **(b) Other than opt-outs, what is preventing migrating AMI meters to OTA billing?**

15
16 **Response IR-149:**

17
18 **(a-b)** Opt-outs notwithstanding, the primary barrier to migrating the remaining AMI meters to
19 over-the-air (OTA) relates to network connectivity. These meters are generally located in
20 areas of the province where meter communications present challenges. These areas are
21 actively being analyzed and addressed through AMI field network mitigation efforts.
22 Tactics that are part of this network mitigation include the installation of mesh node bases
23 to “bridge” areas of poor communication and deployment of firmware updates to improve
24 meter connectivity to the field area network.

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1 **Request IR-150:**

3 **Reference: Exhibit N-8, Appendix 13C**

5 **NS Power stated there are approximately 18,140 opt-out customers who continue to have**
6 **their meters read manually at the meter every other month (i.e., six readings per meter). It**
7 **also states that in 2024, NS Power completed approximately 100,000 manual reads for opt-**
8 **out customers at a total cost of approximately \$1.1 million, which includes carrying costs,**
9 **depreciation, and tax expenses. This roughly translates to about \$11 per reading. If NS**
10 **Power's proposal to reduce six readings per meter per year down to two readings, the annual**
11 **reads would be about 33,333 and the annual cost might be about \$22 per year or about \$1.83**
12 **per month. Presumably not all meter reading expenses would be reduced proportionally**
13 **when the number of total readings are reduced. However, NS Power's suggested fee for**
14 **domestic customers is \$3.81 per month, which is more than double the actual cost it incurred**
15 **in 2024. Please explain, by way of an illustration, where those additional costs causing the**
16 **doubling effect are incurred.**

18 **Response IR-150:**

20 This extrapolation of a per-read cost, while helpful as a basis for conceptual framing, does not
21 reflect the full cost structure or the methodology used to develop the proposed opt-out fee. Care
22 must be taken when assessing costs, rates, or fees from a broad or simplified basis. Such
23 oversimplifications may inadvertently misrepresent the underlying cost drivers or lead to
24 misleading conclusions.

26 The proposed opt-out fee is based on a forward-looking cost model, as described in Section 1 of
27 Appendix 13A and provided as PR-02 Attachment 1, which incorporates operational realities and
28 cost components that do not scale linearly with read frequency. Several key considerations include,
29 but are not limited to, the following:

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- 1 • Fixed labour – to maintain service coverage, a minimum of four Meter Readers (one
2 per region) are required, regardless of read frequency or customer count. While Meter
3 Reader person-hours may decrease with less frequent reads per year, the
4 administrative overhead associated with this fixed labour (supervisor time, data entry
5 and quality control, billing processes) factors into total labour portions of the
6 incremental cost opt-out service.
7
- 8 • Opt-out customer base – the AMI fee model (PR-02 Attachment 1) assumes a decline
9 in opt-out customer base, from approximately 4 percent to 2 percent in 2026 and
10 2027. While the total cost of opt-out meter service decreases (for example, through
11 fixed labour person-hours) with the overall number of opt-out customers, the per-
12 customer cost increases – as fixed costs to serve the remaining non-standard meter
13 service customer base are spread across fewer customers.
14
- 15 • Cost and meter read reductions are not linear – consistent with the points made above,
16 a reduction in the number of manual reads does not proportionally reduce costs. For
17 example, the travel time per read may increase due to less efficient routing with fewer
18 scheduled visits, which also impacts depreciation and overhead.
19
- 20 • Basis of comparison used to develop the sample calculation – the extrapolated per-
21 read provided in the Board’s question, above, appears to be solely based on the data
22 reported in the AMI Opt-out Cost Report (Appendix 13C). The Opt-out Report, while
23 helpful and informative, provides a retrospective view of costs incurred under an
24 annual six-read schedule and does not include the detailed assumptions used in the
25 opt-out fee model (PR-02 Attachment 1). The proposed fee is based on a
26 comprehensive and forward-looking model that, in addition to the factors described
27 in the prior points, takes into consideration:
 - 28 ○ Reduced read frequency for bi-monthly read customers only (i.e. from six
29 to two reads per year) with monthly read customers maintaining the same
30 number of reads (to determine the monthly demand for these customers);

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- Travel time estimates based on the actual location of opt-out customers and organized by meter route;
- Forecast workload volumes based on the actual numbers of opt-out customers to date and bi-annual read rates;
- Incorporation of supervisor oversight (33 percent) for Meter Reader activity; and
- Updated financial assumptions (e.g. WACC and labour rates).

The table below provides an illustrative explanation, comparing the actual 2024 costs (from the Opt-out Report) with the projected 2026 costs for opt-out meter service (provided in PR-02 Attachment 1).

Item		2024 (Actuals, approximated) ¹	2026 (Projected) ²
A	Opt-out Customers	18,140	13,862
B	Total Meter Reads per Year ³	100,000	31,343
C	Total Annual Cost of Non-standard Meter Service	\$1,100,000	\$830,884
D	Annual Cost per Meter Read ["C" / "B"]	\$11.00	\$26.51
E	Annual Cost per Customer ["C" / "A"]	\$60.64	\$59.94

The observed "doubling effect" on a cost-per-read basis is the result of an oversimplified comparison that does not consider the impact of fixed and variable components of the incremental costs that are required to support opt-out customer non-standard service. As illustrated in Columns D and E, the fixed incremental cost of providing non-standard meter service does not scale linearly with read frequency or customer count. Annual per-customer costs in both the 2024 and 2026 scenarios remain stable, at approximately \$60, demonstrating that no actual doubling occurs.

¹ Appendix 13C, AMI Opt-out Costs Report. "Actuals, approximated" is denoted to reflect that, while the 2024 Opt-out Costs Report is reported on an actuals basis, the values are rounded and, in some cases, represent approximates.

² PR-02 Attachment 1, AMI Opt-out Model.

³ For 2024 (Actual), includes the number of meter reads in 2024 at the current frequency (bi-monthly, monthly). For 2026 (Projected), reduces bi-monthly reads to 2 per year (from 6) and maintains monthly reads (12 per year).

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Request IR-151:

Reference: Exhibit N-8, Appendix 13C

NS Power provides the following details for 2024:

- **Approximate number of opt-out customers is 18,140;**
- **Approximate number of completed manual meter readings is 100,000;**
- **Approximate total Meter Services Expenses of \$1.1 million;**
- **Approximate number of inbound calls from opt-out customers was 650; and**
- **Approximate Customer Care Expenses was \$10,000.**

In its opt-out cost development for 2025, provided as PR-02 Attachment 1, NS Power uses:

- **Opt-out customers of 18,819 (reduced to 13,862 in 2026 and 11,089 in 2027);**
- **Manual meter readings of 41,258 (reduced to 31,343 in 2026 and 25,798 in 2027);**
- **Meter Services Expenses including carrying costs, depreciation, and tax of \$734,842 (reducing to \$701,141 in 2026 and \$663,469 in 2027).**
- **Generated Customer Care Calls of 13,333 (reduced to 9,821 in 2026 and 7,857 in 2027);**
- **Opt-out Customer Care Cost of \$144,863 (reduced to \$129,743 in 2026 and \$101,948 in 2027); and**
- **Proposed opt-out monthly charge of \$3.81 in 2026 and \$4.47 in 2027.**

(a) Please explain the large discrepancies between the 2024 actual values provided in Appendix 13C and the cost development values for 2025 used in PR-02 Attachment 1.

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1 Response IR-151:

2
3 (a) NS Power forecast the number of customers that would have opted out as of December 31,
4 2024 while the cost development work was underway during 2024. NS Power estimated
5 18,819, which is higher than the figure of 18,140 at 2024 year-end. NS Power forecasts
6 continued adoption of AMI by customers in 2026 and 2027 and believes that 13,862
7 customers in 2026 and 11,089 customers in 2027 remain reasonable estimates.

8
9 NS Power developed the cost of meter reading in the AMI Opt-out fee by proposing that
10 customers who currently have their meters read bi-monthly would have their meter reading
11 occurrences reduced to twice per year. This is the primary reason for the reduction in
12 number of meter readings and meter reading operating expense from what is included in
13 Appendix 13C.

14
15 While NS Power has reduced the number of meter readings to reduce costs for customers,
16 the Company anticipates this will drive an increase in the number of calls related to
17 estimated bills that are received by the Company's Customer Care Center. This was
18 estimated as 0.71 calls per opt-out customer annually. This increase in anticipated number
19 of calls to the Customer Care Center is the reason for the increase in Customer Care
20 expense.

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1 **Request IR-152:**

2
3 **Reference: PR-03 Attachment 01c**

4
5 **Attachment 01c shows NS Power's proposed increases to its Schedule of Charges (Regulation**
6 **7.1). Those proposed increases cover a wide range, some around 6%, while other are around**
7 **20%, 30%, and even 50%.**

8
9 **(a) Please provide specific justifications for each of the proposed increases.**

10
11 **(b) Please explain why different charges are proposed for items a) and e) when both apply**
12 **to customers equipped with a remote connect-enabled meter.**

13
14 **Response IR-152:**

15
16
17 **(a) The increases in Regulation 7.1 – Schedule of Charges parts (a-e), (i) and (k) are primarily**
18 **due to increased labour costs and increased vehicle-related overhead partially offset by**
19 **decreased overhead charged on labour.**

20
21 The increase in part (j) – Standard Contribution for 3-Phase Service 15 kW and Under is
22 due to a refinement in the cost estimates based upon the difference between standard
23 expenses incurred for new installation of a 3-Phase service as compared to a single-phase
24 service. The primary driver of the incremental costs of a 3-Phase installation is increased
25 materials expense. Labour and traffic control labour have driven an increase as well.

26
27 The increase in part (m) - Pole Attachments exclusive of those Under Joint use Agreements
28 are consistent with the settlement agreement reached with the relevant telecommunications
29 parties. Please see Attachment 1 for a copy of the settlement agreement.

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1 (b) This is primarily due to reduced call handle time for disconnection customer requests as
2 compared to connection requests which may result in creating a new customer account or
3 creating both a disconnection and reconnection at a different address. A component of the
4 charge for connections with AMI meters is for the occasional case in which the meter
5 cannot be connected or disconnected remotely. Disconnections for seasonal customers are
6 not typically timebound, resulting in no need to make a targeted trip to the meter to process
7 the customer request in these instances.

This **POLE ATTACHMENT RATE SETTLEMENT AGREEMENT**, made effective as of the 1st day of September, 2025 (this “Settlement Agreement”)

BETWEEN:

NOVA SCOTIA POWER INCORPORATED, a Nova Scotia company, having its registered office address at 1223 Lower Water Street, 6th Floor, Unit B, Halifax, Nova Scotia B3J 3S8 (“NSP”)

-and-

BRAGG COMMUNICATIONS INC., DOING BUSINESS AS EASTLINK, a Nova Scotia company, having its principal place of business at 6080 Young Street, P.O. Box 8660, Station A, Halifax, Nova Scotia B3K 5M3 (“Eastlink”)

-and-

ROGERS COMMUNICATIONS CANADA INC., a Canadian federal corporation, having its principal place of business at 333 Bloor Street East, 10th Floor, Toronto, Ontario M4W 1G9 (“Rogers”)

-and-

XPLORE INC., a Canadian federal corporation, having its principal place of business at 625 Cochrane Drive, Suite 1000, Markham, Ontario L3R 9R9 (“Xplore”)

(collectively, the “Parties”, and each, a “Party”)

WHEREAS:

1. NSP owns, installs, operates and maintains poles within certain areas of Nova Scotia.
2. Each of Eastlink, Rogers, and Xplore carry on the business of furnishing telecommunications services as defined in the *Telecommunications Act* (Canada) to their subscribers within Nova Scotia and have attached their telecommunication facilities and other equipment to and on poles that are owned by NSP
3. The Parties have reached a settlement on the pole attachment rate.
4. This Settlement Agreement is subject to review and approval by the Board.

NOW, THEREFORE, the Parties agree as follows:

1. The Parties have agreed to a pole attachment rate for 2026, effective the date of approval by the Board of this Settlement Agreement, of \$23.81/per pole/per year, with the rate to be increased by 2% on January 1, 2027 to \$24.29/per pole/per year.
2. The Parties agree and respectfully request that the Board approve this Settlement Agreement.
3. This Settlement Agreement may be executed by the Parties in counterparts, each of which is deemed an original, but all of which together constitutes one and the same agreement. Delivery of an executed counterpart of this Settlement Agreement electronically or by facsimile shall be effective as delivery of an original executed counterpart of this Settlement Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first written above.

Nova Scotia Power Inc.

Signed by:
 Per: Peter Gregg
 Name: Peter Gregg
 Title: President & CEO
 Date: 16-Sep-25 | 1:52 PM ADT

Bragg Communications Inc., dba Eastlink

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

Rogers Communications Canada Inc.

Per: _____
 Name: _____
 Title: _____
 Date: _____

Xplore Inc.

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

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Nova Scotia Power Inc.

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

Bragg Communications Inc., dba Eastlink

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

Rogers Communications Canada Inc.

Signed by:
 Per: Carole Santerre
 Name: Carole Santerre
 Title: VP, Network Ops and National Implementation
 Date: 9/16/2025

Per: _____
 Name: _____
 Title: _____
 Date: _____

Xplore Inc.

Per: _____
 Name: _____
 Title: _____
 Date: _____

Per: _____
 Name: _____
 Title: _____
 Date: _____

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Nova Scotia Power Inc.

Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
Name: _____
Title: _____
Date: _____

Bragg Communications Inc., dba Eastlink

DocuSigned by:
Per: Jeffrey Gillham
Name: Jeffrey Gillham
Title: CEO
Date: 2025-09-18 | 9:23 AM ADT

DocuSigned by:
Per: Billy Lawrence
Name: Billy Lawrence
Title: Chief Financial Officer
Date: 2025-09-17 | 5:04 PM ADT

DS
SI
Steve Irvine
SVP Engineering and

Rogers Communications Canada Inc.

Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
Name: _____
Title: _____
Date: _____

Xplore Inc.

Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
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Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
Name: _____
Title: _____
Date: _____

Rogers Communications Canada Inc.

Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
Name: _____
Title: _____
Date: _____

Bragg Communications Inc., dba Eastlink

Per: _____
Name: _____
Title: _____
Date: _____

Per: _____
Name: _____
Title: _____
Date: _____

Xplore Inc.

Per: Hilbert Chan
Hilbert Chan (Sep 16, 2025 10:23:13 EDT)
Name: Hilbert Chan
Title: Chief Technology Officer
Date: 16-Sep-2025

Per: _____
Name: _____
Title: _____
Date: _____