

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 1

Reference: Application, Section 2, p.9, lines 15-16 states it “has assisted LSEs with information indicating hypothetical cost recovery scenarios, as part of its stakeholder engagement process.”

Please produce all hypothetical cost recovery scenarios, analyses, models, or other information referred to in Section 2 of the Application that IESO-NS shared during the stakeholder engagement process, or has but did not share, including any illustrative allocation of the proposed fee across NSPI's customer classes (residential, commercial, and industrial).

Response IR - 1

Please refer to Attachment 1 for the Illustrative NS Power Bill Impact Model. This model was reviewed with stakeholders at the July 9, 2026 stakeholder session. Please note that this model was produced for illustration and information purposes only – how IESO Nova Scotia fees are collected from customers and the associated cost of service methodology employed to do so are ultimately the responsibility of NS Power and the MEUs.

2027/28 Fee Recovery Calculation

Total Fees Dec-2026 to Mar-2027	\$ 10,375,875
NSPI Interm Fee (Feb-2026 to Nov-2026)	\$ 9,500,000
Fees Apr-2027 to Mar-2028	
NSPI Recovery	\$ 19,875,875
# of Months of Disposition	12
Fees Recovered Apr-27 to Mar-28	\$ 19,875,875

Rate Class Characteristics

	Energy Allocator		Demand Allocator		Customer Count		Billed MWh		12CP	
	2027 Forecast MWh (with losses)	%	3CP	%	Customers	%	2027 Forecast Billed MWh	%	12CP	%
Residential	5,601,352	49.68%	4,351,189	65.06%	486,363	90.51%	5,174,286	49.15%	10,379,557	53.37%
Small General	385,414	3.42%	230,332	3.44%	27,549	5.13%	356,341	3.39%	645,964	3.32%
General	2,335,072	20.71%	1,195,401	17.87%	11,199	2.08%	2,165,416	20.57%	3,598,075	18.50%
Large General	374,976	3.33%	136,936	2.05%	20	0.00%	357,053	3.39%	551,681	2.84%
Small Industrial	273,902	2.43%	125,244	1.87%	2,127	0.40%	254,468	2.42%	390,598	2.01%
Medium Industrial	442,241	3.92%	144,442	2.16%	175	0.03%	414,536	3.94%	521,190	2.68%
Large Industrial	719,039	6.38%	245,492	3.67%	36	0.01%	694,582	6.60%	996,152	5.12%
PHP	311,353	2.76%	203,269	3.04%	1	0.00%	304,283	2.89%	1,410,000	7.25%
Municipal - Lunenburg	28,991	0.26%	20,969	0.31%	1	0.00%	28,085	0.27%	58,928	0.30%
Unmetered	83,268	0.74%	32,357	0.48%	9,882	1.84%	77,000	0.73%	62,357	0.32%
Below the Line	718,273	6.37%	2,407	0.04%		0.00%	700,774	6.66%	834,510	4.29%
Total	11,273,881	100.00%	6,688,037	100.00%	537,357	100.00%	10,526,824	100.00%	19,449,014	184.76%

Lunenburg % of Municipal Load 22.4%

Fee Allocation Options

	Option 1: Energy Allocator				
	2027 Forecast MWh (with losses)	MWh %	Allocated Revenue Requirement	2027 Forecast Billed MWh	¢/kWh
Residential	5,601,352	49.68%	9,875,194	5,174,286	0.19085
Small General	385,414	3.42%	679,486	356,341	0.19068
General	2,335,072	20.71%	4,116,736	2,165,416	0.19011
Large General	374,976	3.33%	661,083	357,053	0.18515
Small Industrial	273,902	2.43%	482,890	254,468	0.18976

- Pros
- Consistent with method IESO allocates costs to MPs
- Cons
- Inconsistent with allocation of costs when system operator was within NSP

Medium Industrial	442,241	3.92%	779,672	414,536	0.18808
Large Industrial	719,039	6.38%	1,267,667	694,582	0.18251
PHP	311,353	2.76%	548,916	304,283	0.18040
Municipal - Lunenbu	28,991	0.26%	51,112	28,085	0.18199
Unmetered	83,268	0.74%	146,802	77,000	0.19065
Below the Line	718,273	6.37%	1,266,317	700,774	0.18070
Total	11,273,881	100.00%	19,875,875	10,526,824	0.18881

Option 2: System Load Factor								
	2027 Forecast MWh (with losses)	MWh %	3CP	3CP %	System Load Factor- Weighted	Allocated Revenue Requirement	2027 Forecast Billed MWh	¢/kWh
Residential	5,601,352	49.68%	4,351,189	65.06%	57.09%	11,347,878	5,174,286	0.21931
Small General	385,414	3.42%	230,332	3.44%	3.43%	681,909	356,341	0.19136
General	2,335,072	20.71%	1,195,401	17.87%	19.34%	3,844,851	2,165,416	0.17756
Large General	374,976	3.33%	136,936	2.05%	2.71%	538,615	357,053	0.15085
Small Industrial	273,902	2.43%	125,244	1.87%	2.16%	429,550	254,468	0.16880
Medium Industrial	442,241	3.92%	144,442	2.16%	3.07%	610,804	414,536	0.14735
Large Industrial	719,039	6.38%	245,492	3.67%	5.07%	1,008,349	694,582	0.14517
PHP	311,353	2.76%	203,269	3.04%	2.90%	575,503	304,283	0.18913
Municipal	28,991	0.26%	20,969	0.31%	0.28%	56,511	28,085	0.20121
Unmetered	83,268	0.74%	32,357	0.48%	0.62%	122,397	77,000	0.15896
Below the Line	718,273	6.37%	2,407	0.04%	3.32%	659,508	700,774	0.09411
Total	11,273,881	100.00%	6,688,037	100.00%	100.00%	19,875,875	10,526,824	0.18881

- Pros**
- Consistent with method NSP allocates generation and had allocat
- Cons**
- Inconsistent with method NSP would allocate system operator cos
 - Inconsistent with method IESO allocates costs to MPs

Energy % (¢ Demand %

51.81%	48.19%
--------	--------

Option 3: Demand Allocator					
	3CP	3CP %	Allocated Revenue Requirement	2027 Forecast Billed MWh	¢/kWh
Residential	4,351,189	65.06%	12,931,101	5,174,286	0.24991
Small General	230,332	3.44%	684,513	356,341	0.19209
General	1,195,401	17.87%	3,552,558	2,165,416	0.16406
Large General	136,936	2.05%	406,954	357,053	0.11398
Small Industrial	125,244	1.87%	372,207	254,468	0.14627
Medium Industrial	144,442	2.16%	429,261	414,536	0.10355
Large Industrial	245,492	3.67%	729,567	694,582	0.10504
PHP	203,269	3.04%	604,086	304,283	0.19853
Municipal	20,969	0.31%	62,316	28,085	0.22188
Unmetered	32,357	0.48%	96,160	77,000	0.12488
Below the Line	2,407	0.04%	7,152	700,774	0.00102
Total	6,688,037	100.00%	19,875,875	10,526,824	0.18881

- Pros**
- Consistent with method NSP allocates transmission in 2026/27 GRA
- Cons**
- Inconsistent with method NSP has allocated system operator costs
 - Inconsistent with method IESO allocates costs to MPs

Option 4: 12CP (OATT)					
	12CP	12CP %	Allocated Revenue Requirement	2027 Forecast Billed MWh	¢/kWh
Residential	10,379,557	53.37%	10,607,365	5,174,286	0.20500
Small General	645,964	3.32%	660,142	356,341	0.18526
General	3,598,075	18.50%	3,677,045	2,165,416	0.16981
Large General	551,681	2.84%	563,789	357,053	0.15790
Small Industrial	390,598	2.01%	399,171	254,468	0.15686
Medium Industrial	521,190	2.68%	532,629	414,536	0.12849
Large Industrial	996,152	5.12%	1,018,015	694,582	0.14657
PHP	1,410,000	7.25%	1,440,946	304,283	0.47355
Municipal	58,928	0.30%	60,221	28,085	0.21442
Unmetered	62,357	0.32%	63,726	77,000	0.08276
Below the Line	834,510	4.29%	852,826	700,774	0.12170
Total	19,449,014	184.76%	19,875,875	10,526,824	0.18881

- Pros**
- Consistent with method costs are recovered under the OATT
- Cons**
- NSP does not currently allocate any costs using the 12CP
 - Inconsistent with method NSP has allocated system operator costs
 - Inconsistent with method IESO allocates costs to MPs

Option 5: System Load Factor for Generation , Demand for Transmission								
	2027 Forecast MWh (with losses)	MWh %	3CP	3CP %	Generation/Transmission Weighted	Allocated Revenue Requirement	2027 Forecast Billed MWh	¢/kWh
Residential	5,601,352	28.80%	4,351,189	65%	61.37%	12,197,539	5,174,286	0.23573
Small General	385,414	1.98%	230,332	3%	3.30%	654,930	356,341	0.18379
General	2,335,072	12.01%	1,195,401	18%	17.28%	3,433,850	2,165,416	0.15858
Large General	374,976	1.93%	136,936	2%	2.04%	404,537	357,053	0.11330
Small Industrial	273,902	1.41%	125,244	2%	1.83%	362,813	254,468	0.14258
Medium Industrial	442,241	2.27%	144,442	2%	2.17%	431,570	414,536	0.10411
Large Industrial	719,039	3.70%	245,492	4%	3.67%	730,101	694,582	0.10511
PHP	311,353	1.60%	203,269	3%	2.89%	574,985	304,283	0.18896
Municipal	28,991	0.15%	20,969	0%	0.30%	58,989	28,085	0.21003
Unmetered	83,268	0.43%	32,357	0%	0.48%	95,034	77,000	0.12342
Below the Line	718,273	3.69%	2,407	0%	0.41%	81,140	700,774	0.01158
Total	19,449,014	100.00%	6,688,037	100.00%	100.00%	19,875,875	10,526,824	0.18881

- Pros**
- Consistent with method NSP allocates generation and transmissio
- Cons**
- Need to define % of costs related to generation and % related to ti
 - Inconsistent with method IESO allocates costs to MPs

Energy % (\$)	Demand %
51.81%	48.19%

Transmission	Generation
80.4%	19.6% (To be Determined)

Option 6: Billed MWh				
	2027 Forecast Billed MWh	%	Allocated Revenue Requirement	¢/kWh
Residential	5,174,286	49.15%	9,769,657	0.18881
Small General	356,341	3.39%	672,813	0.18881
General	2,165,416	20.57%	4,088,559	0.18881
Large General	357,053	3.39%	674,158	0.18881
Small Industrial	254,468	2.42%	480,465	0.18881

- Pros**
- Simple approach
 - Some consistency with other jurisdictions
- Cons**

Medium Industrial	414,536	3.94%	782,692	0.18881
Large Industrial	694,582	6.60%	1,311,452	0.18881
PHP	304,283	2.89%	574,522	0.18881
Municipal	28,085	0.27%	53,028	0.18881
Unmetered	77,000	0.73%	145,385	0.18881
Below the Line	700,774	6.66%	1,323,143	0.18881
Total	10,526,824	100.00%	19,875,875	0.18881

- Does not consider cost causality

	Options Summary ¢/kWh					
	Option 1: Energy Allocator	Option 2: System Load Factor	Option 3: Demand Allocator	Option 4: 12CP (OATT)	Option 5: SLF for Gen , Demand for Tx	Option 6: Billed MWh
Residential	0.191	0.219	0.250	0.205	0.236	0.189
Small General	0.191	0.191	0.192	0.185	0.184	0.189
General	0.190	0.178	0.164	0.170	0.159	0.189
Large General	0.185	0.151	0.114	0.158	0.113	0.189
Small Industrial	0.190	0.169	0.146	0.157	0.143	0.189
Medium Industrial	0.188	0.147	0.104	0.128	0.104	0.189
Large Industrial	0.183	0.145	0.105	0.147	0.105	0.189
PHP	0.180	0.189	0.199	0.474	0.189	0.189
Municipal	0.182	0.201	0.222	0.214	0.210	0.189
Unmetered	0.191	0.159	0.125	0.083	0.123	0.189
Below the Line	0.181	0.094	0.001	0.122	0.012	0.189
Total (Average)	0.189	0.189	0.189	0.189	0.189	0.189

		2027	2027 with IESO Fee	% Increase
Residential				
Customer Charge	\$	21.04	\$ 21.04	1.0%
Energy Charges	\$	176.04	\$ 176.04	
Illustrative IESO Fee			\$ 1.69	
Total Bill	\$	197.08	\$ 198.77	0.9%
Small General				
Customer Charge	\$	22.73	\$ 22.73	1.0%
Energy Charges	\$	205.60	\$ 205.60	
Illustrative IESO Fee			\$ 2.06	
Total Bill	\$	228.34	\$ 230.39	0.9%
General				
Demand Charge	\$	474.94	\$ 474.94	1.4%
Energy Charges	\$	2,255.96	\$ 2,255.96	
Illustrative IESO Fee			\$ 30.63	
Total Bill	\$	2,730.90	\$ 2,761.53	1.1%
Large General				
Demand Charge	\$	38,023.78	\$ 38,023.78	1.6%
Energy Charges	\$	172,139.44	\$ 172,139.44	
Illustrative IESO Fee			\$ 2,754.51	
Total Bill	\$	210,163.22	\$ 212,917.73	1.3%
Small Industrial				
Demand Charge	\$	295.87	\$ 295.87	1.4%
Energy Charges	\$	2,678.79	\$ 2,678.79	
Illustrative IESO Fee			\$ 37.84	
Total Bill	\$	2,974.67	\$ 3,012.51	1.3%
Medium Industrial				
Demand Charge	\$	6,470.56	\$ 6,470.56	1.8%
Energy Charges	\$	20,650.18	\$ 20,650.18	
Illustrative IESO Fee			\$ 371.27	

Impact of IESO Fee on 2027 Total Bills		
Rate Class	Monthly Fee	% Total Bill Increase
Residential	\$ 1.69	0.86%
Small General	\$ 2.06	0.90%
General	\$ 30.63	1.12%
Large General	\$ 2,754.51	1.31%
Small Industrial	\$ 37.84	1.27%
Medium Industrial	\$ 371.27	1.37%
Large Industrial	\$ 2,934.41	1.45%
PHP	\$ 45,742.97	1.39%
Municipal (Lunenburg)	\$ 4,259.34	1.07%

Allocation Scenario (dropdown):

Option 1: Energy Allocator

	Options Summary ¢/kWh					
	Option 1: Energy Allocator	Option 2: System Load Factor	Option 3: Demand Allocator	Option 4: 12CP (OATT)	Option 5: SLF for Gen , Demand for Tx	Option 6: Billed MWh
Residential	0.191	0.219	0.250	0.205	0.236	0.189
Small General	0.191	0.191	0.192	0.185	0.184	0.189
General	0.190	0.178	0.164	0.170	0.159	0.189
Large General	0.185	0.151	0.114	0.158	0.113	0.189
Small Industrial	0.190	0.169	0.146	0.157	0.143	0.189
Medium Industrial	0.188	0.147	0.104	0.128	0.104	0.189
Large Industrial	0.183	0.145	0.105	0.147	0.105	0.189
PHP	0.180	0.189	0.199	0.474	0.189	0.189
Municipal	0.182	0.201	0.222	0.214	0.210	0.189
Unmetered	0.191	0.159	0.125	0.083	0.123	0.189

Total Bill	\$	27,120.74	\$	27,492.01	1.4%
Large Industrial					
Demand Charge	\$	35,797.48	\$	35,797.48	1.8%
Energy Charges	\$	167,004.79	\$	167,004.79	
Illustrative IESO Fee			\$	2,934.41	
Total Bill	\$	202,802.28	\$	205,736.69	1.4%
Extra Large Industrial Dispatchable					
Demand Charge	\$	472,923.30	\$	472,923.30	1.6%
Energy Charges	\$	2,823,782.06	\$	2,823,782.06	
Illustrative IESO Fee			\$	45,742.97	
Total Bill	\$	3,296,705.36	\$	3,342,448.33	1.4%
Municipal (Lunenburg)					
Demand Charge	\$	107,857.55	\$	107,857.55	1.5%
Energy Charges	\$	292,002.75	\$	292,002.75	
Illustrative IESO Fee			\$	4,259.34	
Total Bill	\$	399,860.30	\$	404,119.64	1.1%

Below the Line	0.181	0.094	0.001	0.122	0.012	0.189
Total (Average)	0.189	0.189	0.189	0.189	0.189	0.189

RATE SCHEDULES						Average Bill Calculation				
	units	2026	2027	Variance	% Variance	Charge Determinant	Unit	2026	2027	2027 with Fee
Domestic Service Tariff (Standard Offer)										
Customer Charge	\$/mo	20.08	21.04	0.96	4.8%		1 Customer	20.08	21.04	21.04
Energy Charges										
Base cost of fuel	¢/kWh	8.970	8.841	-0.130	-1.4%	887 kWh	kWh	79.53	78.38	78.38
Non-fuel	¢/kWh	9.353	10.227	0.873	9.3%	887 kWh	kWh	82.92	90.67	90.67
Subtotal		18.324	19.067	0.744	4.1%			162.45	169.04	169.04
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	887 kWh	kWh	-	-	-
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%	887 kWh	kWh	1.38	1.38	1.38
Subtotal		0.156	0.156	0.000	0.0%			1.38	1.38	1.38
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%	887 kWh	kWh	5.83	5.83	5.83
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%	887 kWh	kWh	-0.21	-0.21	-0.21
Subtotal		0.633	0.633	0.000	0.0%			5.62	5.62	5.62
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	887 kWh	kWh	-	-	-
IESO RR	¢/kWh		0.191			887 kWh				1.69
Fuel-related in aggregate	¢/kWh	9.126	8.997	-0.130	-1.4%			80.91	79.76	79.76
Non-fuel related in aggregate	¢/kWh	9.987	10.860	0.873	8.7%			88.54	96.28	97.97
Total		19.113	19.857	0.744	3.9%			169.45	176.04	177.73
Total Bill Calculation										
Customer Charge								20.08	21.04	21.04
Fuel-related in aggregate								80.91	79.76	79.76
Non-fuel related in aggregate								88.54	96.28	97.97
Total Bill								189.53	197.08	198.77
										0.86%
Small General Tariff (Standard Offer)										
Customer Charge	\$/mo	22.00	22.73	0.74	3.4%		1 Customer	22.00	22.73	22.73
Energy Charges										
First 200 kWh Block										
Base cost of fuel	¢/kWh	9.055	8.869	-0.186	-2.1%	200 kWh	kWh	18.11	17.74	17.74
Non-fuel	¢/kWh	9.864	10.927	1.063	10.8%	200 kWh	kWh	19.73	21.85	21.85
Subtotal		18.919	19.796	0.877	4.6%			37.84	39.59	39.59
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	200 kWh	kWh	-	-	-
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%	200 kWh	kWh	0.31	0.31	0.31
Subtotal		0.156	0.156	0.000	0.0%			0.31	0.31	0.31
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%	200 kWh	kWh	1.56	1.56	1.56
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%	200 kWh	kWh	-0.05	-0.05	-0.05
Subtotal		0.753	0.753	0.000	0.0%			1.51	1.51	1.51
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	200 kWh	kWh	-	-	-
IESO RR	¢/kWh		0.191			200 kWh				0.38
Fuel-related in aggregate	¢/kWh	9.211	9.025	-0.186	-2.0%			18.42	18.05	18.05
Non-fuel related in aggregate	¢/kWh	10.617	11.680	1.063	10.0%			21.23	23.36	23.74
Total	¢/kWh	19.828	20.705	0.877	4.4%			39.66	41.41	41.79
All Additional kWhs										
Base cost of fuel	¢/kWh	9.055	8.869	-0.186	-2.1%	878 kWh	kWh	79.50	77.86	77.86
Non-fuel	¢/kWh	8.056	8.925	0.868	10.8%	878 kWh	kWh	70.73	78.35	78.35
Subtotal		17.112	17.794	0.682	4.0%			150.22	156.21	156.21
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	878 kWh	kWh	-	-	-
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%	878 kWh	kWh	1.37	1.37	1.37
Subtotal		0.156	0.156	0.000	0.0%			1.37	1.37	1.37
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%	878 kWh	kWh	6.83	6.83	6.83
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%	878 kWh	kWh	-0.22	-0.22	-0.22
Subtotal		0.753	0.753	0.000	0.0%			6.61	6.61	6.61
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	878 kWh	kWh	-	-	-
IESO RR			0.191			878 kWh				1.67

Fuel-related in aggregate	¢/kWh	9.211	9.025	-0.186	-2.0%		80.87	79.23	79.23
Non-fuel related in aggregate	¢/kWh	<u>8.809</u>	<u>9.678</u>	<u>0.868</u>	<u>9.9%</u>		<u>77.34</u>	<u>84.96</u>	<u>86.64</u>
Total	¢/kWh	18.021	18.703	0.682	3.8%		158.20	164.19	165.87
Total Bill Calculation									
Customer Charge							22.00	22.73	22.73
Fuel-related in aggregate							99.29	97.28	97.28
Non-fuel related in aggregate							<u>98.57</u>	<u>108.32</u>	<u>110.38</u>
Total Bill							219.85	228.34	230.39
									0.90%
General Tariff (Standard Offer)									
Demand Charge	\$/kW	9.809	10.697	0.888	9.1%	44.40 kVA	435.52	474.94	474.94
Transformer Ownership Credit	¢/kVA	-32.000	-32.000	0.000	0.0%				
Energy Charges									
First 200 kWhs per kW of Max Demand									
Base cost of fuel	¢/kWh	8.959	8.482	-0.477	-5.3%	7,992 kWh	716.02	677.90	677.90
Non-fuel	¢/kWh	<u>5.823</u>	<u>6.350</u>	<u>0.527</u>	<u>9.1%</u>	7,992 kWh	<u>465.36</u>	<u>507.48</u>	<u>507.48</u>
Subtotal		14.782	14.832	0.050	0.3%		1,181.37	1,185.38	1,185.38
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	7,992 kWh	-	-	-
FAM BA	¢/kWh	<u>0.207</u>	<u>0.207</u>	<u>0.000</u>	<u>0.0%</u>	7,992 kWh	<u>16.54</u>	<u>16.54</u>	<u>16.54</u>
Subtotal		0.207	0.207	0.000	0.0%		16.54	16.54	16.54
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%	7,992 kWh	50.77	50.77	50.77
DSM BA	¢/kWh	<u>0.010</u>	<u>0.010</u>	<u>0.000</u>	<u>0.0%</u>	7,992 kWh	<u>0.83</u>	<u>0.83</u>	<u>0.83</u>
Subtotal		0.646	0.646	0.000	0.0%		51.60	51.60	51.60
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	7,992 kWh	-	-	-
IESO RR	¢/kWh		0.190			7,992 kWh			15.19
Fuel-related in aggregate	¢/kWh	9.166	8.689	-0.477	-5.2%		732.56	694.44	694.44
Non-fuel related in aggregate	¢/kWh	<u>6.469</u>	<u>6.996</u>	<u>0.527</u>	<u>8.1%</u>		<u>516.95</u>	<u>559.08</u>	<u>574.27</u>
Total	¢/kWh	15.635	15.685	0.050	0.3%		1,249.51	1,253.52	1,268.71
All Additional kWhs									
Base cost of fuel	¢/kWh	8.959	8.482	-0.477	-5.3%	8,121 kWh	727.62	688.88	688.88
Non-fuel	¢/kWh	<u>2.759</u>	<u>3.008</u>	<u>0.250</u>	<u>9.1%</u>	8,121 kWh	<u>224.03</u>	<u>244.31</u>	<u>244.31</u>
Subtotal		11.718	11.491	-0.227	-1.9%		951.65	933.20	933.20
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	8,121 kWh	-	-	-
FAM BA	¢/kWh	<u>0.207</u>	<u>0.207</u>	<u>0.000</u>	<u>0.0%</u>	8,121 kWh	<u>16.81</u>	<u>16.81</u>	<u>16.81</u>
Subtotal		0.207	0.207	0.000	0.0%		16.81	16.81	16.81
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%	8,121 kWh	51.59	51.59	51.59
DSM BA	¢/kWh	<u>0.010</u>	<u>0.010</u>	<u>0.000</u>	<u>0.0%</u>	8,121 kWh	<u>0.84</u>	<u>0.84</u>	<u>0.84</u>
Subtotal		0.646	0.646	0.000	0.0%		52.43	52.43	52.43
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	8,121 kWh	-	-	-
IESO RR	¢/kWh		0.190			8,121 kWh			15.44
Fuel-related in aggregate	¢/kWh	9.166	8.689	-0.477	-5.2%		744.43	705.69	705.69
Non-fuel related in aggregate	¢/kWh	<u>3.404</u>	<u>3.654</u>	<u>0.250</u>	<u>7.3%</u>		<u>276.47</u>	<u>296.75</u>	<u>312.19</u>
Total	¢/kWh	12.571	12.343	-0.227	-1.8%		1,020.90	1,002.44	1,017.88
Both Blocks:									
Fuel-related in aggregate							1,476.99	1,400.13	1,400.13
Non-fuel related in aggregate							793.42	855.83	886.46
Total							2,270.41	2,255.96	2,286.59
Total Bill Calculation									
Demand Charge							435.52	474.94	474.94
Fuel-related in aggregate							1,476.99	1,400.13	1,400.13
Non-fuel related in aggregate							<u>793.42</u>	<u>855.83</u>	<u>886.46</u>
Total Bill							2,705.93	2,730.90	2,761.53
									1.12%
Large General Tariff									
Demand Charge (Ratcheted)	\$/kVA	11.174	11.989	0.815	7.3%	3,171.6 kVA	35,438	38,024	38,024
Transformer Ownership Credit	¢/kVA	-32.000	-32.000	0.000	0.0%				
Energy Charges									
Base cost of fuel	¢/kWh	8.440	7.700	-0.740	-8.8%	1,487,721 kWh	125,568	114,555	114,555
Non-fuel	¢/kWh	<u>2.724</u>	<u>2.923</u>	<u>0.199</u>	<u>7.3%</u>	1,487,721 kWh	<u>40,523</u>	<u>43,480</u>	<u>43,480</u>
Subtotal		11.164	10.623	-0.541	-4.9%		166,091	158,035	158,035
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	1,487,721 kWh	-	-	-
FAM BA	¢/kWh	<u>0.158</u>	<u>0.158</u>	<u>0.000</u>	<u>0.0%</u>	1,487,721 kWh	<u>2,351</u>	<u>2,351</u>	<u>2,351</u>
Subtotal		0.158	0.158	0.000	0.0%		2,351	2,351	2,351
DSM PCR	¢/kWh	0.768	0.768	0.000	0.0%	1,487,721 kWh	11,430	11,430	11,430
DSM BA	¢/kWh	<u>0.022</u>	<u>0.022</u>	<u>0.000</u>	<u>0.0%</u>	1,487,721 kWh	<u>323</u>	<u>323</u>	<u>323</u>
Subtotal		0.790	0.790	0.000	0.0%		11,754	11,754	11,754
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	1,487,721 kWh	-	-	-
IESO RR	¢/kWh		0.185			1,487,721 kWh			2,754.51
Fuel-related in aggregate	¢/kWh	8.598	7.858	-0.740	-8.6%		127,918	116,906	116,906
Non-fuel related in aggregate	¢/kWh	<u>3.514</u>	<u>3.713</u>	<u>0.199</u>	<u>5.7%</u>		<u>52,277</u>	<u>55,233</u>	<u>57,988</u>
Total	¢/kWh	12.112	11.571	-0.541	-4.5%		180,195	172,139	174,894

IESO Nova Scotia (IG) IR-1
Attachment 1

Demand Charge						35,438.38				38,023.78	38,023.78			
Fuel-related in aggregate						127,918.22				116,906.08	116,906.08			
Non-fuel related in aggregate						52,276.98				55,233.35	57,987.87			
Total Bill						215,633.57				210,163.22	212,917.73	1.31%		
Small Industrial Tariff														
Demand Charge						\$/kVA	7.496	8.143	0.647	8.6%	36.33 kVA	272	296	296
Transformer Ownership Credit						¢/kVA	-32.000	-32.000	0.000	0.0%				
Energy Charges														
First 200 kWhs per kVA of Max Demand														
Base cost of fuel						¢/kWh	8.803	8.333	-0.471	-5.3%	9,970 kWh	877.66	830.75	830.75
Non-fuel						¢/kWh	5.029	5.463	0.434	8.6%	9,970 kWh	501.34	544.61	544.61
Subtotal							13.832	13.795	-0.036	-0.3%		1,379.00	1,375.37	1,375.37
FAM AA						¢/kWh	0.000	0.000	0.000	0.0%	9,970 kWh	-	-	-
FAM BA						¢/kWh	0.144	0.144	0.000	0.0%	9,970 kWh	14.36	14.36	14.36
Subtotal							0.144	0.144	0.000	0.0%		14.36	14.36	14.36
DSM PCR						¢/kWh	0.720	0.720	0.000	0.0%	9,970 kWh	71.75	71.75	71.75
DSM BA						¢/kWh	0.033	0.033	0.000	0.0%	9,970 kWh	3.31	3.31	3.31
Subtotal							0.753	0.753	0.000	0.0%		75.06	75.06	75.06
SCRR						¢/kWh	0.000	0.000	0.000	0.0%	9,970 kWh	-	-	-
IESO RR						¢/kWh	0.190				9,970 kWh			18.92
Fuel-related in aggregate						¢/kWh	8.947	8.477	-0.471	-5.3%		892.02	845.11	845.11
Non-fuel related in aggregate						¢/kWh	5.781	6.216	0.434	7.5%		576.39	619.67	638.59
Total						¢/kWh	14.729	14.692	-0.036	-0.2%		1,468.41	1,464.78	1,483.70
All Additional kWhs														
Base cost of fuel						¢/kWh	8.803	8.333	-0.471	-5.3%	9,970 kWh	877.66	830.75	830.75
Non-fuel						¢/kWh	2.713	2.947	0.234	8.6%	9,970 kWh	270.49	293.84	293.84
Subtotal							11.516	11.280	-0.236	-2.1%		1,148.15	1,124.60	1,124.60
FAM AA						¢/kWh	0.000	0.000	0.000	0.0%	9,970 kWh	-	-	-
FAM BA						¢/kWh	0.144	0.144	0.000	0.0%	9,970 kWh	14.36	14.36	14.36
Subtotal							0.144	0.144	0.000	0.0%		14.36	14.36	14.36
DSM PCR						¢/kWh	0.720	0.720	0.000	0.0%	9,970 kWh	71.75	71.75	71.75
DSM BA						¢/kWh	0.033	0.033	0.000	0.0%	9,970 kWh	3.31	3.31	3.31
Subtotal							0.753	0.753	0.000	0.0%		75.06	75.06	75.06
SCRR						¢/kWh	0.000	0.000	0.000	0.0%	9,970 kWh	-	-	-
IESO RR						¢/kWh	0.190				9,970 kWh			18.92
Fuel-related in aggregate						¢/kWh	8.947	8.477	-0.471	-5.3%		892	845	845
Non-fuel related in aggregate						¢/kWh	3.466	3.700	0.234	6.8%		346	369	388
Total						¢/kWh	12.413	12.177	-0.236	-1.9%		1,238	1,214	1,233
Both Blocks:														
Fuel-related in aggregate											1,784.03	1,690.22	1,690.22	
Non-fuel related in aggregate											921.95	988.58	1,026.41	
Total											2,705.98	2,678.79	2,716.63	
Total Bill Calculation														
Demand Charge											272.36	295.87	295.87	
Fuel-related in aggregate											1,784.03	1,690.22	1,690.22	
Non-fuel related in aggregate											921.95	988.58	1,026.41	
Total Bill											2,978.34	2,974.67	3,012.51	1.27%
Medium Industrial Tariff														
Demand Charge						\$/kVA	10.710	11.269	0.559	5.2%	574.2 kVA	6,149	6,471	6,471
Transformer Ownership Credit						¢/kVA	-32.000	-32.000	0.000	0.0%				
Energy Charges														
Base cost of fuel						¢/kWh	8.503	7.648	-0.855	-10.1%	197,398 kWh	16,784.50	15,097.53	15,097.53
Non-fuel						¢/kWh	2.179	2.292	0.114	5.2%	197,398 kWh	4,300.68	4,525.26	4,525.26
Subtotal							10.682	9.941	-0.741	-6.9%		21,085.18	19,622.80	19,622.80
FAM AA						¢/kWh	0.000	0.000	0.000	0.0%	197,398 kWh	-	-	-
FAM BA						¢/kWh	0.206	0.206	0.000	0.0%	197,398 kWh	406.64	406.64	406.64
Subtotal							0.206	0.206	0.000	0.0%		406.64	406.64	406.64
DSM PCR						¢/kWh	0.306	0.306	0.000	0.0%	197,398 kWh	604.77	604.77	604.77
DSM BA						¢/kWh	0.008	0.008	0.000	0.0%	197,398 kWh	15.97	15.97	15.97
Subtotal							0.314	0.314	0.000	0.0%		620.74	620.74	620.74
SCRR						¢/kWh	0.000	0.000	0.000	0.0%	197,398 kWh	-	-	-
IESO RR						¢/kWh	0.188				197,398 kWh			371.27
Fuel-related in aggregate						¢/kWh	8.709	7.854	-0.855	-9.8%		17,191	15,504	15,504
Non-fuel related in aggregate						¢/kWh	2.493	2.607	0.114	4.6%		4,921	5,146	5,517
Total							11.202	10.461	-0.741	-6.6%		22,113	20,650	21,021
Total Bill Calculation														
Demand Charge											6,149	6,471	6,471	
Fuel-related in aggregate											17,191	15,504	15,504	
Non-fuel related in aggregate											4,921	5,146	5,517	
Total Bill											28,262	27,121	27,492	1.37%

Large Industrial Tariff									
Demand Charge (Ratcheted)	\$/kVA	9.268	10.006	0.739	8.0%	3,577.5 kVA	33,155	35,797	35,797
Transformer Ownership Credit	¢/kVA	-32.000	-32.000	0.000	0.0%				
Interruptible Credit	\$/kVA	-7.638	-7.667	-0.029	0.4%				
Distribution Cost Adder		2.161	2.327	0.166	7.7%				
Energy Charges									
Firm									
Base cost of fuel	¢/kWh	8.234	7.484	-0.750	-9.1%	1,607,829 kWh	132,386.69	120,328.94	120,328.94
Non-fuel	¢/kWh	2.061	2.225	0.164	8.0%	1,607,829 kWh	33,133.74	35,774.77	35,774.77
Subtotal		10.295	9.709	-0.586	-5.7%		165,520.43	156,103.72	156,103.72
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	1,607,829 kWh	-	-	-
FAM BA	¢/kWh	0.247	0.247	0.000	0.0%	1,607,829 kWh	3,971.34	3,971.34	3,971.34
Subtotal		0.247	0.247	0.000	0.0%		3,971.34	3,971.34	3,971.34
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%	1,607,829 kWh	6,495.63	6,495.63	6,495.63
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%	1,607,829 kWh	434.11	434.11	434.11
Subtotal		0.431	0.431	0.000	0.0%		6,929.74	6,929.74	6,929.74
SCRR (Transmission)	¢/kWh	0.000	0.000	0.000	0.0%	1,607,829 kWh	-	-	-
SCRR (Distribution)	¢/kWh	0.000	0.000	0.000	0.0%	1,607,829 kWh	-	-	-
IESO RR	¢/kWh		0.183			1,607,829 kWh			2,934.41
Subtotal		0.000	0.000	0.000	0.0%				
Fuel-related in aggregate	¢/kWh	8.481	7.731	-0.750	-8.8%		136,358	124,300	124,300
Non-fuel related in aggregate	¢/kWh	2.492	2.656	0.164	6.6%		40,063	42,705	45,639
Total		10.973	10.387	-0.586	-5.3%		176,422	167,005	169,939
Total Bill Calculation									
Demand Charge							33,155	35,797	35,797
Fuel-related in aggregate							136,358	124,300	124,300
Non-fuel related in aggregate							40,063	42,705	45,639
Total Bill							209,576	202,802	205,737
									1.45%
Municipal Tariff									
Demand Charge (Ratcheted)	\$/kVA	11.248	12.226	0.978	8.7%	8,822 kVA	99,226	107,858	107,858
Transformer Ownership Credit	¢/kVA	-32.000	-32.000	0.000	0.0%				
Energy Charges									
Base cost of fuel	¢/kWh	9.005	8.924	-0.081	-0.9%	2,340,431 kWh	210,745.96	208,852.89	208,852.89
Non-fuel	¢/kWh	2.595	2.821	0.226	8.7%	2,340,431 kWh	60,734.55	66,017.91	66,017.91
Subtotal		11.600	11.744	0.145	1.2%		271,480.51	274,870.80	274,870.80
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	2,340,431 kWh	-	-	-
FAM BA	¢/kWh	0.105	0.105	0.000	0.0%	2,340,431 kWh	2,457.45	2,457.45	2,457.45
Subtotal		0.105	0.105	0.000	0.0%		2,457.45	2,457.45	2,457.45
DSM PCR	¢/kWh	0.650	0.650	0.000	0.0%	2,340,431 kWh	15,212.80	15,212.80	15,212.80
DSM BA	¢/kWh	-0.023	-0.023	0.000	0.0%	2,340,431 kWh	-538.30	-538.30	-538.30
Subtotal		0.627	0.627	0.000	0.0%		14,674.50	14,674.50	14,674.50
SCRR	¢/kWh	0.000	0.000	0.000	0.0%	2,340,431 kWh	-	-	-
IESO RR	¢/kWh		0.182			2,340,431 kWh			4,259.34
Fuel-related in aggregate	¢/kWh	9.110	9.029	-0.081	-0.9%		213,203	211,310	211,310
Non-fuel related in aggregate	¢/kWh	3.222	3.448	0.226	7.0%		75,409	80,692	84,952
Total		12.332	12.476	0.145	1.2%		288,612	292,003	296,262
Total Bill Calculation									
Demand Charge							99,226	107,858	107,858
Fuel-related in aggregate							213,203	211,310	211,310
Non-fuel related in aggregate							75,409	80,692	84,952
Total Bill							387,838	399,860	404,120
									1.07%
Extra Large Industrial Dispatchable									
Demand Charges									
Demand Charge	\$/kVA	12.731	14.235	1.504	11.8%	69,149 kVA	880,317	984,327	984,327
Transformer Ownership Credit	¢/kVA	0.000	0.000	0.000	0.0%				
Interruptible Credit	\$/kVA	-8.402	-8.434	-0.032	0.4%	60,638 kVA	-	511,404	511,404
Distribution Cost Adder	\$/kVA	0.000	0.000	0.000	0.0%				
Total		4.329	5.801	1.472	34.0%				
Energy Charges									
Firm									
Base cost of fuel	¢/kWh	7.653	8.762	1.109	14.5%	5,840,000 kWh	446,923.50	511,694.76	511,694.76
Non-fuel	¢/kWh	2.274	2.374	0.100	4.4%	5,840,000 kWh	132,809.39	138,656.28	138,656.28
Subtotal		9.927	11.136	1.209	12.2%		579,732.89	650,351.04	650,351.04
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	5,840,000 kWh	-	-	-
FAM BA	¢/kWh	0.000	0.000	0.000	0.0%	5,840,000 kWh	-	-	-
Subtotal		0.000	0.000	0.000	0.0%		-	-	-

IESO Nova Scotia (IG) IR-1
Attachment 1

DSM PCR	¢/kWh	0.000	0.000	0.000	0.0%	5,840,000 kWh	-	-	-
DSM BA	¢/kWh	<u>0.000</u>	<u>0.000</u>	<u>0.000</u>	<u>0.0%</u>	5,840,000 kWh	-	-	-
Subtotal		0.000	0.000	0.000	0.0%		-	-	-
SCR (Transmission)	¢/kWh	0.000	0.000	0.000		5,840,000 kWh	-	-	-
SCR (Distribution)	¢/kWh	<u>0.000</u>	<u>0.000</u>	<u>0.000</u>		5,840,000 kWh	-	-	-
Subtotal		0.000	0.000	0.000			-	-	-
IESO RR	¢/kWh	0.180				5,840,000 kWh	-	10,535.16	
Fuel-related in aggregate	¢/kWh	7.653	8.762	1.109	14.5%	5,840,000 kWh	446,923.50	511,694.76	511,694.76
Non-fuel related in aggregate	¢/kWh	<u>2.274</u>	<u>2.374</u>	<u>0.100</u>	<u>4.4%</u>	5,840,000 kWh	<u>132,809.39</u>	<u>138,656.28</u>	<u>149,191.44</u>
Total		9.927	11.136	1.209	12.2%		579,732.89	650,351.04	660,886.20
Interruptible									
Base cost of fuel	¢/kWh	7.653	8.762	1.109	14.5%	19,516,901 kWh	1,493,589.35	1,710,050.71	1,710,050.71
Non-fuel	¢/kWh	<u>2.274</u>	<u>2.374</u>	<u>0.100</u>	<u>4.4%</u>	19,516,901 kWh	<u>443,840.38</u>	<u>463,380.30</u>	<u>463,380.30</u>
Subtotal		9.927	11.136	1.209	12.2%		1,937,429.73	2,173,431.02	2,173,431.02
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%	19,516,901 kWh	-	-	-
FAM BA	¢/kWh	<u>0.000</u>	<u>0.000</u>	<u>0.000</u>	<u>0.0%</u>	19,516,901 kWh	-	-	-
Subtotal		0.000	0.000	0.000	0.0%		-	-	-
DSM PCR	¢/kWh	0.000	0.000	0.000	0.0%	19,516,901 kWh	-	-	-
DSM BA	¢/kWh	<u>0.000</u>	<u>0.000</u>	<u>0.000</u>	<u>0.0%</u>	19,516,901 kWh	-	-	-
Subtotal		0.000	0.000	0.000	0.0%		-	-	-
SCR (Transmission)	¢/kWh	0.000	0.000	0.000	0.0%	19,516,901 kWh	-	-	-
SCR (Distribution)	¢/kWh	<u>0.000</u>	<u>0.000</u>	<u>0.000</u>	<u>0.0%</u>	19,516,901 kWh	-	-	-
Subtotal		0.000	0.000	0.000	0.0%		-	-	-
IESO RR	¢/kWh	0.180				19,516,901 kWh	-	35,207.81	
Fuel-related in aggregate	¢/kWh	7.653	8.762	1.109	14.5%		1,493,589	1,710,051	1,710,051
Non-fuel related in aggregate	¢/kWh	<u>2.274</u>	<u>2.374</u>	<u>0.100</u>	<u>4.4%</u>		<u>443,840</u>	<u>463,380</u>	<u>498,588</u>
Total		9.927	11.136	1.209	12.2%		1,937,430	2,173,431	2,208,639
Total Bill Calculation									
Demand Charge							370,839	472,923	472,923
Fuel-related in aggregate							1,940,513	2,221,745	2,221,745
Non-fuel related in aggregate							576,650	602,037	647,780
Total Bill							2,888,001	3,296,705	3,342,448
									1.39%

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 2

Reference: **Application, Section 3.2, p. 12, lines 13-15.**

In future years, IESO Nova Scotia proposes to apply for approval of its fees as part of its revenue requirement applications using the Proposed Mechanism – in that way, Step 1 of the fee-setting process would be combined with the remaining steps of that process.

Please explain how the fee recovery mechanism and related charge would operate if the Board did not approve the revenue requirement application in whole and instead returned it to IESO-NS, with recommendations. In your response, please include the timeline IESO-NS anticipates for any iterative review and approval process.

Response IR - 2

The matter of the NSEB's jurisdiction and implications regarding *More Access to Energy Act* (MAEA) s.29 is currently before the Board for its consideration under M12663, IESO Nova Scotia's 2026/2027 Revenue Requirement and Fees application. IESO Nova Scotia respectfully submits that questions regarding any iterative review and approval process under the scenario raised by the IG is best addressed in Revenue Requirement, Proposed Expenditures, and Fees applications proceedings.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

19 Otherwise, MAEA s.29(3) provides that “Until the Energy Board approves the proposed
20 expenditure and revenue requirements for the fiscal year and the fees the IESO proposes to charge
21 during the fiscal year, the fees approved for the previous fiscal year remain in effect unless the
22 Energy Board orders otherwise.” Accordingly, it is assumed fees approved for the previous fiscal
23 year would remain in effect until new fiscal year fees are approved by the NSEB.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 3

Reference: Application, Section 3.3, p. 13, lines 1-3 and footnote 7.

(a) Please distinguish between “inseparable costs” and “direct costs” including those associated with interconnection studies, with specific examples, and their associated GL codes.

(b) Please confirm whether any wheeling transactions are reasonably anticipated to occur across the Nova Scotia transmission system, and if so, whether the energy volumes associated with such transactions are included in, or excluded from, the LSE consumption volumes used to calculate the base fee, true-up, and load allocation adjustment under the Fee Calculation Model.

(c) If wheeling transactions are anticipated, can the IESO-NS confirm whether all parties using the transmission system, including any entity engaged in wheeling transactions across the Nova Scotia transmission system, (whether or not scheduled through an LSE) will contribute to the IESO-NS costs under the Proposed Mechanism? If not, please explain how this use of the transmission system is being accounted for within the proposed mechanism.

(d) Please explain how IESO-NS verifies that all direct costs associated with

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

interconnection studies are fully “netted out” of the revenue requirement forming the basis of the fees proposed in this Application, such that customers are not paying, through the Proposed Mechanism, for costs that ought to be directly recovered from specific interconnection customers.

- (e) Does “netted out” mean that they are not included as part of the s. 29 Revenue Requirement, or does it mean that there is an accounting after the fact when costs are recovered from an interconnection customer? Please explain. If the latter, why are they included in the first place?

Response IR - 3

- a) Please refer to LEI IR-1 and 3. IESO Nova Scotia tracks the hours worked by employees on interconnection customer projects. The associated direct costs are calculated outside of the GL.

- b) Please refer to NSEB IR-21. IESO Nova Scotia is aware of Nalcor’s Transmission Service Reservation for flow from Newfoundland to New Brunswick as part of the Maritime Link arrangement which is effectively a wheeling transaction. Whereas wheeled energy through the province is not serving Nova Scotia LSE’s internal load, these volumes would not comprise the load served forecast or actuals for the purpose of allocating IESO Nova Scotia

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

38 fees. Otherwise, IESO Nova Scotia will obtain load served forecast and actuals from LSEs
39 for all LSE served load irrespective of the source from which the load is being served.
40

41 c) Please refer to NSEB IR-21. Entities wheeling transactions through Nova Scotia such as
42 intertie traders are not captured under the Fee Recovery Mechanism as proposed. However,
43 users of the transmission system such as those described will continue to be subject to fees
44 under the existing OATT. As described in the Application and elsewhere throughout this
45 proceeding's IR responses, IESO Nova Scotia's proposed fee recovery mechanism stands
46 apart from the OATT as IESO Nova Scotia does not have ownership of the OATT.
47

48 d) Please refer to LEI IR-3. IESO Nova Scotia verifies that all direct costs associated with
49 interconnection studies are charged to the interconnection customers by tracking employee
50 hours by project and billing the interconnection customers for this time based on employee
51 compensation rates. Additionally, there is an allocation of overhead charged to the
52 interconnection customers intended to cover a portion of shared services.
53

54 e) The term "netted out" means that the expected direct costs for interconnection studies are
55 not included as part of the s. 29 Revenue Requirement.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 4

Reference: Application, s. 3.3, p.13 Identification of Market Participants, and

Reference: Appendix 2, p. 7, footnote 5.

(a) Please confirm whether any large industrial customer in Nova Scotia is, or in the reasonably foreseeable future (e.g. within the next 5 years) may be, directly connected to the transmission system rather than served through NSPI or an MEU (as an LSE, transmission customer, market participant or otherwise).

(b) If such a customer exists or is contemplated, please explain how that customer's proportionate share of IESO-NS's revenue requirement would be recovered under the Proposed Mechanism, and whether the Proposed Mechanism would require modification to capture that load.

Response IR - 4

a) At this time, IESO Nova Scotia is not aware of any large industrial customer that would be able to direct connect to the transmission system while avoiding their load being served, at least in part, by one of the existing or forthcoming LSEs (i.e. NS Power, MEUs, and RtR). There currently does not exist in Nova Scotia an opportunity for load to be a wholesale market participant.

b) Please refer to part a). Pursuant to Appendix 2 - FTI's IESO Enduring Fee Recovery Mechanism footnote 5, "In some jurisdictions, such as the states operated by ISO-NE,

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

22 transmission-connected load is formally served by an LSE and therefore ISO Core Costs
23 are recovered through the same retail rate process as used for distribution-level customers.”
24 This approach fits within current Nova Scotia electricity market and the proposed Fee
25 Recovery Mechanism without modification.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 5

Reference: Application, Section 3.4, p.15, footnote 9; and Section 4, p.36, lines 6-10.

Preamble: IESO-NS notes that a Renewable to Retail (RtR) Licensed Retail Supplier is expected to begin providing electricity to customers in December 2026, and that this entity is considered an LSE for the purpose of applying IESO-NS fees, but that IESO-NS is not proposing to apply fees to this entity prospectively at this time.

(a) Please confirm whether, and how, the existing LSEs (including NSPI) will be credited or otherwise adjusted once the RtR supplier becomes operational and is added as a fee-paying LSE, including whether any retroactive load allocation adjustment would apply to the period between the RtR supplier's commercial operation date and the date it begins paying IESO-NS fees, and the carrying costs applicable to any such retroactive adjustment.

(b) Please confirm what proportion of total Nova Scotia load the RtR supplier is expected to represent once operational, and the estimated impact on NSPI's proportionate load share (and therefore NSPI's fee) once the RtR supplier is included in the allocation.

(c) Provide all workpapers and calculations to respond to this IR.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Response IR - 5

a) Existing LSEs will be credited or adjusted once the RtR supplier becomes operational and is added as a fee-paying LSE. This will likely be done by way of the next revenue requirement, proposed expenditures, and fees application following the RtR supplier becoming operational, which will include an adjustment of all fees to LSEs, and will include any retroactive load allocation adjustments for the period the RtR was serving load but not charged IESO Nova Scotia fees.

At a high level, IESO Nova Scotia fees to all LSEs would be redistributed based on the new LSE's proportionate share of load served for the province, with corresponding reductions in load served for the existing LSEs. With respect to carrying costs, please refer to CA IR-5. Any associated fee adjustments will be transparently modelled and the calculation model included in the corresponding application with all relevant inputs and assumptions provided for NSEB and intervenor review.

b) The RtR supplier is expected to represent approximately 3.5% of total Nova Scotia load once fully operational. NS Power's proportion of total Nova Scotia load is expected to decline from approximately 98.6% to 95.1% once the RtR supplied is fully operational.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

38 c) Please refer to Attachment 1.

2026 Load Forecast Report

Figure 3: Historic and Forecast Net System Requirement and System Peak

Year	NSR (GWh)	NSR Growth (%)	System Peak (MW)	Peak Growth (%)
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
2022	11,134	2.1	2,216	12.6
2023	11,131	0	2,455	10.8
2024	11,326	1.8	2,088	-14.9
2025	11,469	1.3	2,267	8.6
2026F	11,575	0.9	2,484	9.6
2027F	11,424	-1.3	2,497	0.5
2028F	11,525	0.9	2,526	1.2
2029F	11,556	0.3	2,549	0.9
2030F	11,568	0.1	2,563	0.6
2031F	11,621	0.5	2,593	1.2
2032F	11,689	0.6	2,620	1
2033F	11,722	0.3	2,652	1.2
2034F	11,815	0.8	2,689	1.4
2035F	11,939	1	2,730	1.5
2036F	12,097	1.3	2,765	1.3

2026 Load Forecast Report

Figure 41: RTR Forecast by Class

Class	2026 Impact (GWh)	2027 Impact (GWh)	2028+ Impact (GWh)
Residential	2	41	49
Small General	0	6	7
General Demand	10	173	207
Large General	2	26	31
Small Industrial	1	13	15
Medium Industrial	3	47	56
Large Industrial	2	37	45
Unmetered	1	8	10
Total	21	352	421

Calculated

Renewable to Retail %

Year	NSR (GWh)	RtR Forecast	Total	RtR %
2026F	11,575	21	11,596	0.2%
2027F	11,424	352	11,776	3.0%
2028F	11,525	421	11,946	3.5%
2029F	11,556	421	11,977	3.5%
2030F	11,568	421	11,989	3.5%
2031F	11,621	421	12,042	3.5%
2032F	11,689	421	12,110	3.5%
2033F	11,722	421	12,143	3.5%
2034F	11,815	421	12,236	3.4%
2035F	11,939	421	12,360	3.4%

	2026/27		Future State	
	MWh	%	MWh	%
NSPI	10,525,592	98.6%	10,155,413	95.09%
Berwick Electric Commission	39,919	0.37%	39,919	0.37%
Riverport Electric Light Commission	9,526	0.09%	9,526	0.09%
Town of Mahone Bay	14,625	0.14%	14,625	0.14%
Town of Antigonish	90,500	0.85%	90,500	0.85%
Renewable to Retail			370,179	3.47%
Total	10,680,161	100%	10,680,161	100%

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

1 **Request IR - 6**

2 **Reference: Application, Section 3.4, p. 16, lines 19-22.**

3 (a) Please describe the milestones for “Phase 2 steady state operation” and outline the
4 anticipated timing for accomplishing these milestones.

5 (b) Does IESO-NS commit to consulting and engaging with interested parties as part
6 of the re-evaluation of the fee recovery mechanism?

7 **Response IR - 6**

8

9 a) Please refer to NSEB IR-8.

10

11 b) Yes.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 7

(a) When the IESO-NS assumes ownership of the OATT and system operation/dispatch functions in Phase 2, is it anticipated that (i) the billing determinant used to allocate IESO-NS's revenue requirement to LSEs will need to switch from energy consumption (MWh) to peak load (MW), and/or (ii) the IESO-NS's fee recovery could be incorporated into the OATT or transmission revenue requirement process rather than continuing as a direct ISO-only charge?

(b) Please explain why or why not.

Response IR - 7

a) Please refer to NSEB IR-9. Consideration of a new OATT based IESO Nova Scotia fee recovery mechanism will include what billing determinant is best suited for IESO Nova Scotia's revenue requirement and fees, as well as whether a direct ISO-only charge remains appropriate.

b) Please refer to part a).

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 8

Reference: Application, Section 3.4, p.18, lines 1-7 and Section 4.2, p.27, lines 21-23.

Preamble: The Proposed Mechanism allocates the fixed monthly charge among LSEs based on each LSE's proportionate share of annual energy consumption (MWh), rather than a peak demand (MW) or other capacity-based measure.

(a) Did IESO-NS or its consultants analyze whether a MWh-based allocation among LSEs produces a materially different result, at the LSE level, than a peak-demand-based allocation would? If so, please provide that analysis.

(b) Please confirm that IESO-NS's main reasons to apply a fixed charge for energy consumption rather than metered are the two stated benefits to IESO-NS: revenue predictability and revenue stability. If not confirmed, please explain otherwise.

(c) Please discuss the pros and cons of a fixed charge rather than a volumetric approach from the perspective of the LSE's and the ultimate customers who will be paying the charge.

(d) Please confirm that the selected allocation methodology operates solely at the LSE level, based on each LSE's aggregate actual annual energy consumption (MWh), and are not affected by, and do not depend on, the

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

19 billing methodology (e.g., peak demand/ MW or MWh) that any individual
20 LSE uses to allocate costs among its own retail customer classes.

- 21 (e) Please confirm whether IESO-NS has assessed whether the use of MWh
22 creates any disconnect for LSEs that bill their own customers on a demand
23 basis, such that an LSE's share of IESO-NS costs (assessed on MWh) may
24 not proportionately match how that LSE recovers those costs from the
25 customer classes actually driving that usage. Please elaborate and confirm
26 whether this may create any cross-subsidization issues into the future.

27 **Response IR - 8**
28

- 29 a) Please refer to NSEB IR-20. An analysis of the results under a peak-demand based
30 allocation as compared to the proposed fee recovery mechanism was not conducted, as a
31 peak-demand based allocation approach was ruled-out for the reasons noted in the
32 Application Section 4.1 and FTI's reports in Appendix 1 and Appendix 2.
33

- 34 b) Revenue predictability and stability were the core considerations for the IESO. Due to the
35 small size of the Nova Scotia system it might be more prone to strong fluctuations in energy
36 consumption or capacity usage from year to year than larger systems. Hence IESO Nova
37 Scotia annually approved costs might be to an important extent over or under-recovered if

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

a charging structure based on consumption or peak capacity were introduced. Also, while energy consumption or peak capacity can significantly vary month to month but the costs of an IESO are primarily fixed (and thus not expect to significantly vary month to month), the proposed recovery mechanism is a fixed fee that does not vary across months.

In addition, FTI also considered two other key factors when proposing energy consumption (MWh) be used as the allocator rather than peak usage (MW): (1) MWh charges are the most common type of charge applied to LSEs among the benchmarking group in the FTI Jurisdictional Scan,¹ and (2) energy consumption (MWh) is generally a more stable than peak usage (MW) which is important in the proposed methodology which relies on forecasts.

It should be noted that economic principles were also a consideration of FTI, however, it was ultimately determined that “the potential efficiency losses associated with pricing distortions are likely limited under any reasonable billing determinant, as these costs represent a relatively small share of total customer charges compared with other cost categories, such as generation and transmission costs. Therefore, economic principles provide limited guidance regarding the selection of an appropriate billing determinant in this context.”²

¹ See table 1, Appendix 1 FTI Jurisdictional Scan.

² Appendix 2, FTI Recommendation Report, pp. 10-11.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

56 c) The fixed charge was chosen to ensure revenue predictability and stability for IESO Nova
57 Scotia given the small size of the Nova Scotia system (see as well IR-10 part b) and IESO
58 Nova Scotia being a relatively new entity, a small organization, and dependent on these
59 charges as its only source of revenue. The stability and predictability of the mechanism
60 was also considered beneficial to MPs, especially the smaller MEUs, who may prefer
61 making consistent payments rather than unpredictable monthly invoices. As described
62 above, under a volumetric charge, IESO Nova Scotia would be exposed to the risk of over-
63 or under-recovery if actual consumption deviated from forecast levels, requiring additional
64 true-ups and potentially more frequent updates to charges.

65
66 A more stable and predictable revenue stream will reduce IESO Nova Scotia's potential risk
67 of needing additional short-term financing to fund its operations should energy consumption
68 drop substantially below forecast; the interest on this additional short-term financing would
69 eventually be paid by all grid users.

70
71 Finally, other "pros" are discussed in the answer to b) above.

72
73 Potential "cons" of a fixed charge could include less accurate in-year allocation among MPs if
74 an MP were to have substantially higher or lower usage than forecast (particularly if an MP
75 were to enter or leave the market unexpectedly). However, the relative impact of such over-or

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

76 under-allocation of ISO Costs to MPs would have a significantly smaller impact on the total
77 financial balance of that MP. In contrast, the impact of forecast errors in annual energy
78 consumption on the financial balance of IESO Nova Scotia under a volumetric charge could
79 be much larger in relative terms. Hence a fixed charge is less likely to impact the financing
80 needs of an MP than a volumetric charge would impact the financing needs of IESO Nova
81 Scotia. Finally, the volumetric charge may also be more intuitive to MPs as a more commonly
82 seen billing practice.

83
84 d) Confirmed.

85
86 e) Please refer to part d) above and LEI IR-3. The use of a direct charge based on proportional
87 MWh has no bearing on how LSEs will pass those costs onto their customers. IESO Nova
88 Scotia does not anticipate proportionate mismatches between customer classes based on
89 how LSEs charge IESO Nova Scotia costs to those customer classes, in part because IESO
90 Nova Scotia revenue requirement to date is comprised nearly exclusively of inseparable
91 core costs which benefit all customers broadly. Accordingly, IESO Nova Scotia is not
92 aware at this time of risk associated with possible cross-subsidization. Finally, IESO Nova
93 Scotia respectfully submits that the issues raised here by the IG are more appropriately
94 addressed via corresponding LSE's own cost recovery mechanism applications.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 9

Reference: Application, Section 5, Figure 14, p.41; Figure 15, p.42-43.

Preamble: The Fee Calculation Model determines the remaining 2025/26 and 2026/27 revenue requirement fees to be collected from LSEs over the four-month period from December 2026 to March 2027, following interim fee payments of \$950,000/month from NSPI between February and November 2026.

(a) Please confirm the total amount of "Total Unrecovered Fees" to be collected from NSPI over the four-month period under both True-Up Option 1 (\$10,366,000 before true-up) and True-Up Option 2 (\$10,056,655 with true-up) and confirm the resulting average monthly fee to NSPI under each option over that period.

(b) Did IESO-NS or Power Advisory consider alternatives to full recovery of the 2025/26 and 2026/27 shortfall within the four-month December 2026-March 2027 period, such as spreading recovery of the accumulated shortfall over a longer period (e.g., 12 or 24 months) beyond IESO-NS's 2026/27 fiscal year end? If so, please provide that analysis, in spreadsheet format if available, with all formulae intact, including any consideration of the impact on NSPI's ability to smooth the resulting cost in its own rates to ratepayers.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Response IR – 9

a) The total and monthly fees to be collected from NS Power are summarized below.

NS Power Fees	Total Unrecovered Fees	Monthly Fees
Option 1 (before true-up)	\$10,366,000	\$2,591,500
Option 2 (with true-up)	\$10,056,655	\$2,514,164

These NS Power fees can also be found in Application Figures 14 and 15 respectively.

b) Yes, alternate recovery periods were considered. Fees with different recovery periods can be calculated in Appendix 3 – IESO Fee Calculation Model by changing the green-shaded cell under “# Months of Revenue Collection” in tab ‘Fee Recovery Calculation’. Fees for alternate recovery periods are provided below.

Market Participant	Monthly Fees - Option 1		
	4 Months	12 Months	24 Months
NSPI	\$2,591,500	\$868,889	\$438,045
Berwick Electric Commission	\$18,785	\$6,298	\$3,175
Riverport Electric Light Commission	\$4,483	\$1,503	\$758
Town of Mahone Bay	\$6,882	\$2,308	\$1,163
Town of Antigonish	\$42,587	\$14,279	\$7,199
Total	\$2,664,236	\$893,276	\$450,340

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Market Participant	Monthly Fees - Option 2		
	4 Months	12 Months	24 Months
NSPI	\$2,514,164	\$842,959	\$424,973
Berwick Electric Commission	\$18,494	\$6,201	\$3,126
Riverport Electric Light Commission	\$4,413	\$1,480	\$746
Town of Mahone Bay	\$6,776	\$2,272	\$1,145
Town of Antigonish	\$41,929	\$14,058	\$7,087
Total	\$2,585,776	\$866,970	\$437,078

28 The timeframe in which NS Power recovers associated costs from its customers, including a
29 “smoothed” recovery over a longer period of time, is ultimately independent of the
30 timeframe in which IESO Nova Scotia recovers its costs from NS Power. As such, IESO
31 Nova Scotia cannot accurately opine on the method and timing of NS Power’s recovery of
32 its fees from its customers.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 10

**Reference: Application, Section 4.4 (Load Allocation Adjustment), p.33, lines 4-6;
Appendix 2, p.19-20.**

**Preamble: The load allocation adjustment reconciles each LSE's forecast versus actual
annual load share, without affecting IESO-NS's total revenue collected.**

(a) Please provide a worked, LSE-specific numerical example (using NSPI and
at least one MEU) illustrating how the load allocation adjustment would be
calculated and applied in a year where NSPI's actual load share differs from
its forecast load share by 1 percentage point, showing the resulting dollar
adjustment to NSPI's monthly fee.

(b) Please confirm whether IESO-NS contemplates disclosing, on an annual
basis, the actual versus forecast load share for each LSE (including NSPI)
used to calculate the load allocation adjustment, and whether that
information would be made available to intervenors as part of IESO-NS's
annual revenue requirement and fee applications.

Response IR - 10

a) An LSE-specific example in which NS Power's actual load share is 1
percentage point lower than the forecast load share is provided below. Please

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

19 note there are illustrative true-up and load allocation adjustment calculations in
20 Appendix 3.

2026/27 Load Allocation Adjustment

	2026/27 Forecast %	Annual Base Fee 2026/27	2026/27 Actual %	2026/27 Annual Fee Based on Actual Energy %	2026/27 Allocation Adjustment	Monthly Load Allocation Adjustment
NSPI	98.55%	\$14,635,202	97.55%	\$14,486,701	-\$148,501	-\$12,375
Berwick	0.37%	\$55,504	0.56%	\$83,284	\$27,779	\$2,315
Riverport	0.09%	\$13,245	0.17%	\$25,238	\$11,993	\$999
Mahone Bay	0.14%	\$20,336	0.24%	\$35,333	\$14,997	\$1,250
Antigonish	0.85%	\$125,834	1.48%	\$219,566	\$93,732	\$7,811
Total	100.0%	\$14,850,121	100.0%	\$14,850,121	\$0	\$0

21

22 b) Confirmed. IESO Nova Scotia will disclose proportional load data, forecast and
23 actual, via fee calculation models in its annual Revenue Requirement, Proposed
24 Expenditures, and Fees applications.

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Request IR - 11

**Reference: Application, Section 4.3 (Revenue Requirement True-up - Option 2), p.31-32;
Section 5, p.39, footnote 17.**

**Preamble: IESO-NS's preferred true-up methodology (Option 2) would see revenue
requirement variances trued up via compliance filing on a one-year lag, in advance of the
full prudency review that would otherwise occur in the next revenue requirement application.**

(a) Please describe in detail the process, materials, and level of Board and
stakeholder scrutiny that IESO-NS contemplates would accompany a
compliance filing under True-Up Option 2, including whether Intervenors
would have an opportunity to review and comment on the compliance filing
before NSEB approval of the resulting adjustment to fees.

(b) Please confirm whether any subsequent prudency review of costs trued up
via a compliance filing under Option 2 would occur, and if so, when, and
what recourse (if any) LSEs or ratepayers would have if costs were later
found to be imprudent after having already been collected via the
compliance filing true-up.

(c) Please quantify the carrying costs (i.e., interest rate assumption and
methodology) that would apply to an under-recovery (and over-recovery)

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

of IESO-NS's costs under True-Up Option 1 (two-year lag) as compared to True-Up Option 2 (one-year lag via compliance filing) and confirm how those carrying costs are reflected in the fee amounts proposed in Figures 14 through 17 of the Application.

Response IR - 11

- a) Under True-up Option 2, a compliance filing would be made shortly after NSEB decision issuance on FY2 Revenue Requirement, Proposed Expenditures, and Fees application, in which all aspects of IESO Nova Scotia's fees for FY2 would be known and approved based on the FY2 fee calculation model. Therefore, the compliance filing would provide the FY2 fee calculation model with one adjustment: the over or under recovery amount based on FY1's revenue requirement actuals as recorded via the Net Revenue Requirement Deferral and Variance Mechanism (DVM). IESO Nova Scotia anticipates that compliance filing would include details related to the variance for information only at that time. For the sake of expediting NSEB approval of the refund or recovery of charges via the compliance filing, and realizing the noted corresponding benefits on a timely basis, IESO Nova Scotia submits that no NSEB process regarding the review of the variance and corresponding refund or charge via the fees would be required at that time. This would be so on the basis that prudence review of the variance, where applicable, would occur during the next FY3

Fee Recovery Mechanism Application
(Nova Scotia Energy Board M13007)

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Responses to Industrial Group (IG) Information Requests

NON-CONFIDENTIAL

Revenue Requirement, Proposed Expenditures, and Fees application submitted to the NSEB by December 31 in FY2. Recourse for LSEs would be considered as part of the FY3 application – any potential adjustments to the fees could be made through further compliance filings as part of that proceeding. Please also refer to CA IR-2.

b) Please refer to part a).

c) Please refer to CA IR-5 and SBA IR-9. IESO Nova Scotia's current carrying cost is 2.32% applied to month-end balances. The revenue requirement reflects actual interest expense incurred so the impact of any over- or under-recovery in a year will be reflected in the DVM for that year. In subsequent years, as an example, a \$500,000 true-up would result in approximately \$17K carrying costs for Option 1 and approximately \$5K carrying costs for Option 2. These carrying costs would be reflected in the "Finance" line item in subsequent revenue requirements rather than being included within the DVM. An over-recovery would result in lower carrying costs and an under-recovery would result in higher carrying costs in subsequent revenue requirements.