NON-CONFIDENTIAL

Request IR-1:

Reference: Appendix 16 at 30:

> **"While there may be differences in impact between RtR generation located in Cape Breton and in the Halifax area, those impacts do not change if the generation is connected to transmission or distribution systems in each location." And "There are arguments that generation delivered to load within the same distribution zone should not have to bear the burden of transmission system losses. However, network service transmission relies on the use of average loss factors."**

(a) Please provide NS Power's estimates of marginal transmission line losses by zone of generator.

(b) Does the statement that "network service transmission relies on the use of average loss factors" mean that NS Power believes that averaging losses across the province is required?

(i) If so, please explain what requires such spatial averaging, whether law, regulation, physics or data availability.

(ii) If not, please confirm that this statement is simply a reflection of NS Power's past practice.

(c) Please provide NS Power's estimates of losses on its primary distribution system.

(i) If those estimates are disaggregated by type of primary service, time period, or other parameters, please provide the disaggregated values.

(d) Please describe the status of NSPI's line-loss study required by the COSS settlement and order, and provide any workproducts produced to date.

NON-CONFIDENTIAL

Response IR-1:

(a) Please refer to **Attachment 1** for Transmission Bus Loss Factor and Short Circuit Level Data. Attachment 1 provides the incremental locational loss factor data associated with each NS Power transmission substation.

(b) Yes.

(i) Section 28.5 of the existing Open Access Transmission Tariff addresses real power losses associated with the Network Integration Transmission Tariff. It requires that the Network Customer be responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider in accordance with Schedule 9 of the Tariff. Schedule 9 specifies that for Network Service, the Transmission provider will apply the system average loss factor, which will be calculated annually.

(ii) Not applicable.

(c) Please refer to the Cost of Service model, **Application Appendix 11A, Exhibit 9B** for a summary of the primary distribution losses by rate class.

(d) NS Power is finalizing an action plan for the Class Load Data Collection and Analysis Project, which will include purchase and deployment of new meters to implement a refreshed sample design. The Capital Work Order for this project will be submitted in the 2016 Annual Capital Expenditure Plan in November, 2015. The Line Loss Determination Model requires a year of new class load data before it can be completed, so its expected completion is in 2017.

2014 Transmission Bus
Loss Factor and Short Circuit Level Data

				Incremental Locational Loss Factors											Short Circuit Level			
Station ID	NAME	kV	LOCATION	110 MW	100 MW	90 MW	80 MW	70 MW	60 MW	50 MW	40 MW	30 MW	20 MW	10 MW	Maximum (MVA)	X/R Ratio	Minimum (MVA)	X/R Ratio
101S	WOODBINE	230	Morley Road, Sydney	11.5%	11.3%	11.1%	11.0%	10.9%	10.7%	10.6%	10.4%	10.3%	10.1%	10.0%	2691	16.5	1626	22.7
120H	BRUSHY HILL	230	East Uniacke, Grove Road	0.9%	0.9%	0.8%	0.7%	0.7%	0.6%	0.6%	0.5%	0.4%	0.4%	0.3%	3356	12.3	1540	15.4
199S	PT.ACONI	230	Point Aconi	13.4%	13.1%	12.9%	12.8%	12.6%	12.4%	12.2%	12.0%	11.8%	11.6%	11.5%	1661	15.8	1289	21.9
3C	HASTINGS	230	Port Hastings	9.8%	9.7%	9.6%	9.5%	9.3%	9.2%	9.1%	8.9%	8.8%	8.7%	8.6%	3090	11.2	1726	17.1
67N	ONSLOW	230	Onslow	3.4%	3.3%	3.3%	3.2%	3.1%	3.0%	3.0%	2.9%	2.8%	2.7%	2.7%	4104	13.7	1841	18.8
88S	LINGAN	230	Lingan	13.3%	13.1%	12.9%	12.8%	12.6%	12.5%	12.3%	12.2%	12.0%	11.9%	11.8%	3896	22.5	1716	20.8
91N	DALHOUSIE MTN	230	Dalhousie Mountain, Pictou	5.3%	5.2%	5.1%	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	4.2%	4.2%	2285	8.2	1384	11.7
99W	BWATER_A 230	230	Bridgewater	0.0%	-0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.7%	-0.9%	-1.0%	-1.1%	-1.3%	1517	12.9	926	14.0
99W	BWATER_B 230	230	Bridgewater	0.0%	-0.2%	-0.3%	-0.4%	-0.6%	-0.7%	-0.8%	-1.0%	-1.1%	-1.2%	-1.4%	1261	10.3	808	11.4
100C	PORCUPINE	138	Cape Porcupine	10.0%	9.9%	9.7%	9.6%	9.4%	9.3%	9.1%	9.0%	8.8%	8.7%	8.5%	2336	9.9	1483	13.9
101H	COBEQUID	138	Sackville	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%	-0.6%	-0.6%	-0.7%	-0.7%	-0.8%	-0.8%	3111	10.6	1322	12.8
101W	BMPC-TMP	138	Brooklyn	0.0%	-0.2%	-0.4%	-0.6%	-0.9%	-1.1%	-1.3%	-1.5%	-1.7%	-1.9%	-2.1%	1045	9.9	598	10.2
103H	LAKESIDE	138	Beechville (Lakeside)	0.5%	0.4%	0.4%	0.3%	0.3%	0.2%	0.2%	0.1%	0.0%	0.0%	-0.1%	2758	12.6	1322	15.8
103W	GOLD RIVER	138	Beech Hill Rd., Chester	1.2%	0.9%	0.5%	0.2%	-0.2%	-0.5%	-0.9%	-1.2%	-1.6%	-2.0%	-2.4%	591	4.7	471	5.5
104H	KEMPT RD	138	3176 Kempt Road, Halifax	-0.5%	-0.6%	-0.6%	-0.6%	-0.7%	-0.7%	-0.7%	-0.8%	-0.8%	-0.8%	-0.9%	2834	13.0	1229	13.1
104S	BADDECK	138	Baddeck	15.4%	15.1%	14.7%	14.4%	14.1%	13.8%	13.4%	13.1%	12.8%	12.5%	12.2%	1058	6.9	597	6.7
104W	BROOKLYN	138	Brooklyn	0.0%	-0.2%	-0.4%	-0.6%	-0.8%	-1.1%	-1.3%	-1.5%	-1.7%	-1.8%	-2.1%	1034	9.8	592	10.0
108H	BURNSIDE	138	Burnside, Dartmouth	-0.2%	-0.3%	-0.3%	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%	-0.6%	-0.6%	3366	13.1	1296	12.2
113H	EAST DARTMOUTH	138	Cherry Brook	-1.0%	-1.0%	-1.1%	-1.1%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.6%	2060	8.7	1038	10.2
120H	BRUSHY HILL	138	East Uniacke, Grove Road	0.8%	0.7%	0.7%	0.6%	0.5%	0.5%	0.4%	0.4%	0.3%	0.2%	0.2%	3307	12.9	1465	16.5
126H	PORTERS LAKE	138	Porters Lake	-0.6%	-0.7%	-0.9%	-1.0%	-1.2%	-1.3%	-1.4%	-1.6%	-1.7%	-1.8%	-2.0%	1167	6.3	750	7.6
127H	AEROTECH	138	Aerotech Ind. Park, Hwy 102	0.2%	0.1%	0.0%	-0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.7%	-0.8%	-0.9%	1511	6.4	945	7.9
129H	KEARNEY	138	102	0.6%	0.5%	0.4%	0.3%	0.2%	0.2%	0.1%	0.0%	-0.1%	-0.2%	-0.3%	2005	10.2	1120	13.2
131H	LUCASVILLE	138	Lucasville Road	0.0%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.4%	-0.5%	-0.5%	-0.6%	3042	11.4	1351	14.2
137H	HAMMOND PLAINS	138	Hammond Plains Rd, Bedford	0.6%	0.6%	0.5%	0.4%	0.3%	0.3%	0.2%	0.1%	0.1%	0.0%	-0.1%	2269	11.9	1209	14.9
139H	DARTMOUTH CROSS	138	Burnside, Dartmouth	-0.8%	-0.8%	-0.9%	-0.9%	-1.0%	-1.0%	-1.1%	-1.1%	-1.2%	-1.2%	-1.3%	2634	10.0	1166	11.1
17V	ST CROIX	138	St. Croix	-0.2%	-0.3%	-0.4%	-0.5%	-0.6%	-0.8%	-0.9%	-1.0%	-1.1%	-1.2%	-1.4%	1756	8.1	1036	10.6
1C	TUPPER	138	Point Tupper	11.5%	11.3%	11.1%	11.0%	10.8%	10.6%	10.5%	10.3%	10.1%	10.0%	9.8%	2290	11.3	1480	15.7
1H	WATER ST	138	Lower Water Street, Halifax	-0.3%	-0.3%	-0.4%	-0.4%	-0.5%	-0.6%	-0.6%	-0.6%	-0.7%	-0.8%	-0.8%	2307	10.8	1165	13.0
1N	ONSLOW	138	Onslow	3.4%	3.3%	3.2%	3.1%	3.0%	2.9%	2.8%	2.7%	2.7%	2.6%	2.5%	2259	11.8	1491	13.4
22C	CLEVELAND	138	Cleveland	10.7%	10.5%	10.3%	10.1%	9.9%	9.8%	9.6%	9.4%	9.2%	9.0%	8.8%	1653	7.1	1161	9.5
22N	CHURCHST	138	Church Street, Amherst	5.9%	5.4%	4.9%	4.4%	3.8%	3.3%	2.8%	2.3%	1.8%	1.2%	0.6%	1015	5.2	936	5.8
2C	HASTINGS	138	Port Hastings	10.1%	9.9%	9.8%	9.7%	9.5%	9.4%	9.2%	9.1%	9.0%	8.8%	8.7%	2755	12.5	1632	17.7
2H	ARMDALE	138	Armdale	0.1%	0.0%	-0.1%	-0.1%	-0.2%	-0.3%	-0.3%	-0.4%	-0.4%	-0.5%	-0.6%	2410	11.2	1215	14.0
2S	VICTORIA	138	Victoria Junction	12.9%	12.7%	12.5%	12.4%	12.2%	12.0%	11.8%	11.7%	11.5%	11.3%	11.1%	2152	12.9	1180	14.1
30N	MACCAN	138	Maccan	6.0%	5.5%	5.0%	4.5%	4.0%	3.4%	2.9%	2.5%	1.9%	1.4%	0.8%	1068	5.4	982	6.1
30W	SOURIQUOIS	138	Shelburne (East of)	-0.5%	-1.0%	-1.5%	-2.1%	-2.7%	-3.2%	-3.8%	-4.4%	-5.0%	-5.6%	-6.3%	567	4.4	376	5.1
3S	GANNON	138	North Sydney	14.4%	14.1%	13.8%	13.5%	13.2%	13.0%	12.7%	12.4%	12.1%	11.8%	11.6%	1159	6.7	711	7.4
99V	99V-HIGHBURY	138	Kentville	-2.2%	-2.5%	-2.7%	-2.9%	-3.2%	-3.4%	-3.7%	-3.9%	-4.1%	-4.3%	-4.7%	1046	5.9	708	6.8
43V	CANAAN RD	138	White Rock	-2.4%	-2.6%	-2.8%	-3.0%	-3.3%	-3.5%	-3.7%	-3.9%	-4.1%	-4.3%	-4.6%	1168	6.0	759	7.0
47C	NEWPAGE	138	Point Tupper	11.4%	11.2%	11.0%	10.9%	10.7%	10.5%	10.4%	10.2%	10.0%	9.9%	9.7%	2271	11.0	1450	14.6
49N	MICH-GRAN	138	Granton	6.5%	6.4%	6.3%	6.1%	6.0%	5.9%	5.8%	5.6%	5.5%	5.4%	5.3%	2188	14.7	1471	17.6
4C	LOCHABER	138	Antigonish	8.7%	8.5%	8.2%	8.0%	7.8%	7.5%	7.3%	7.0%	6.8%	6.5%	6.3%	1135	5.7	911	6.9

Note: This table does not imply that the indicated size of generator can be interconnected at the bus listed.
All interconnections are subject to System Impact Studies.

2014 Transmission Bus
Loss Factor and Short Circuit Level Data

				Incremental Locational Loss Factors											Short Circuit Level			
Station ID	NAME	kV	LOCATION	110 MW	100 MW	90 MW	80 MW	70 MW	60 MW	50 MW	40 MW	30 MW	20 MW	10 MW	Maximum (MVA)	X/R Ratio	Minimum (MVA)	X/R Ratio
50N	TRENTON	138	Trenton	6.8%	6.6%	6.5%	6.4%	6.3%	6.1%	6.0%	5.9%	5.8%	5.6%	5.5%	2853	18.9	1732	22.1
50W	MILTON	138	Milton	-0.3%	-0.5%	-0.7%	-0.9%	-1.1%	-1.2%	-1.4%	-1.6%	-1.8%	-2.0%	-2.2%	1155	10.2	639	10.5
51V	TREMONT B61_	138	Tremont - East Tremont	-2.2%	-2.6%	-2.9%	-3.2%	-3.5%	-3.9%	-4.2%	-4.5%	-4.9%	-5.2%	-5.6%	809	5.5	572	5.9
59C	ST PETERS	138	St. Peters	12.0%	11.7%	11.5%	11.2%	11.0%	10.7%	10.4%	10.2%	9.9%	9.6%	9.4%	1050	5.8	814	7.2
5S	GLEN TOSH	138	Glen Tosh	16.2%	15.8%	15.5%	15.2%	14.9%	14.6%	14.2%	13.9%	13.6%	13.3%	13.0%	1309	7.9	615	6.7
67C	WHYC TAP	138	Whycocomagh	13.8%	13.5%	13.2%	12.9%	12.6%	12.3%	12.0%	11.7%	11.4%	11.1%	10.8%	1019	6.2	669	6.8
67C	WHYCOCO	138	Whycocomagh	14.2%	13.8%	13.5%	13.1%	12.7%	12.4%	12.0%	11.6%	11.3%	10.9%	10.6%	766	5.7	550	6.3
74N	SPRNGHILL	138	East of Springhill Town	4.8%	4.4%	4.1%	3.6%	3.2%	2.8%	2.4%	2.0%	1.5%	1.1%	0.6%	1187	5.3	1083	6.0
74W	MICHBWTP	138	Oakhill	-0.2%	-0.4%	-0.5%	-0.6%	-0.8%	-0.9%	-1.0%	-1.1%	-1.2%	-1.4%	-1.6%	1374	12.0	792	13.5
74W	MICH B-W	138	Oakhill	-0.2%	-0.3%	-0.4%	-0.5%	-0.7%	-0.9%	-1.0%	-1.1%	-1.2%	-1.4%	-1.6%	1303	11.0	768	12.7
75W	WESTHAVER	138	Blockhouse - Maitland	0.1%	0.0%	-0.2%	-0.4%	-0.6%	-0.8%	-1.0%	-1.2%	-1.3%	-1.5%	-1.8%	1018	8.2	659	9.9
79N	HOPEWELL	138	Hopewell	5.8%	5.7%	5.6%	5.5%	5.4%	5.3%	5.2%	5.1%	5.0%	4.9%	4.8%	2465	17.6	1557	21.1
81N	DEBERT	138	Debert	3.4%	3.2%	3.1%	2.9%	2.7%	2.6%	2.4%	2.3%	2.1%	2.0%	1.8%	1535	7.0	1204	8.3
82V	ELMSDALE	138	Elmsdale	0.7%	0.6%	0.5%	0.3%	0.2%	0.0%	-0.1%	-0.3%	-0.4%	-0.6%	-0.7%	1272	5.9	880	7.2
85S	WRECK COVE	138	Wreck Cove, Victoria Co.	19.5%	19.0%	18.6%	18.2%	17.8%	17.3%	16.9%	16.5%	16.1%	15.7%	15.3%	1353	14.2	457	6.0
87H	MUSQ.HBR	138	Musquodoboit Harbour	0.0%	-0.2%	-0.4%	-0.6%	-0.8%	-1.0%	-1.2%	-1.4%	-1.7%	-1.9%	-2.1%	825	5.7	592	6.7
87W	HUBBARDS	138	Hubbards, Mill Lake Road	0.3%	0.1%	-0.1%	-0.4%	-0.6%	-0.9%	-1.1%	-1.4%	-1.6%	-1.9%	-2.1%	870	5.1	632	6.3
88S	LINGAN A	138	Lingan	13.5%	13.3%	13.1%	13.0%	12.8%	12.6%	12.5%	12.3%	12.1%	12.0%	11.8%	2024	17.4	1184	18.7
88S	LINGAN B	138	Lingan	13.4%	13.2%	13.0%	12.9%	12.7%	12.5%	12.4%	12.2%	12.0%	11.9%	11.7%	2031	19.3	1187	19.6
90H	SACVILLE	138	Bedford, Lower Sackville	-0.2%	-0.3%	-0.3%	-0.4%	-0.4%	-0.4%	-0.5%	-0.5%	-0.6%	-0.6%	-0.7%	3473	12.8	1414	15.0
91H	TUFTCOVE	138	Tufts Cove, Dartmouth	-0.3%	-0.3%	-0.3%	-0.3%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.5%	3670	18.4	1333	14.0
92H	ST.MARG.	138	Head of St. Margaret's Bay	0.0%	-0.1%	-0.3%	-0.5%	-0.6%	-0.8%	-0.9%	-1.1%	-1.2%	-1.4%	-1.6%	1190	5.6	786	7.1
92N	AMHERST WIND	138	Southampton Rd. Amherst	6.9%	6.3%	5.7%	5.2%	4.6%	4.0%	3.5%	2.9%	2.4%	1.8%	1.2%	233	5.2	128	3.7
93N	GLEN DHU	138	Glen Dhu, Pictou	8.6%	8.4%	8.1%	7.9%	7.7%	7.5%	7.2%	7.0%	6.8%	6.5%	6.3%	1205	5.8	959	7.1
99W	BRIDGEWATER	138	Bridgewater	-0.2%	-0.4%	-0.5%	-0.6%	-0.8%	-0.9%	-1.0%	-1.1%	-1.2%	-1.4%	-1.6%	1376	12.2	793	13.7
9W	TUSKET_A	138	Tusket Falls	-1.7%	-2.3%	-2.8%	-3.4%	-4.0%	-4.6%	-5.1%	-5.8%	-6.4%	-7.0%	-7.7%	451	5.3	294	5.1
9W	TUSKET_B	138	Tusket Falls	N/A	N/A	N/A	-3.7%	-4.5%	-5.3%	-6.1%	-6.9%	-7.7%	-8.5%	-9.4%	460	8.4	300	7.3
103C	CHETICAMP	69	Cheticamp	...	...	...	...	...	...	20.8%	17.3%	14.2%	11.4%	8.4%	80	3.6	77	3.7
103H	LAKESIDE	69	Lakeside industrial park	...	...	...	...	...	...	-0.4%	-0.6%	-0.8%	-0.9%	-1.2%	299	31.0	259	30.2
106W	Pubnico Pt	69	Pubnico Point	...	...	...	...	...	...	N/A	N/A	N/A	N/A	-13.4%	232	5.2	128	3.7
109S	LINGAN WIND	69	Lingan	...	...	...	...	...	...	12.6%	12.2%	11.7%	11.3%	10.8%	525	4.6	415	5.3
10N	ABER ST	69	Springhill	...	...	...	...	...	...	2.8%	2.2%	1.6%	1.0%	0.3%	365	9.5	355	10.0
10V	NICTAUX	69	Nictaux Falls	...	...	...	...	...	...	-3.5%	-4.1%	-4.8%	-5.4%	-6.2%	470	5.6	327	5.1
10W	TUSKET GT	69	Tusket	...	...	...	...	...	...	-5.7%	-6.6%	-7.5%	-8.5%	-9.6%	486	5.2	259	4.9
11N	CEMENT	69	Pleasant Valley	...	...	...	...	...	...	5.3%	4.5%	3.8%	3.0%	2.2%	298	4.8	279	5.0
11S	KELTIC DR	69	Keltic Drive, Coxheath	...	...	...	...	...	...	10.4%	9.9%	9.3%	8.8%	8.2%	406	5.7	337	6.2
11V	PARADISE	69	Paradise	...	...	...	...	...	...	-1.9%	-2.9%	-4.0%	-5.0%	-6.1%	377	5.1	241	4.2
11W	KING ST	69	King Street, Yarmouth	...	...	...	...	...	...	-4.5%	-6.3%	-8.1%	-10.1%	-12.4%	276	2.2	191	2.8
124H	AKERLEY	69	Akerley Boulevard, Burnside	...	...	...	...	...	...	-0.1%	-0.2%	-0.3%	-0.4%	-0.5%	1371	8.9	872	10.6
12V	LEQUILLE	69	LeQuille (SE Annapolis)	...	...	...	...	...	...	0.2%	-1.2%	-2.7%	-4.3%	-5.8%	398	4.8	201	3.4
13V	GULCH	69	Bear River	...	...	...	...	...	...	2.2%	0.3%	-1.6%	-3.5%	-5.5%	471	3.3	194	2.7
14V	RIDGE	69	5 km SSE Bear River	...	...	...	...	...	...	3.3%	1.4%	-0.5%	-2.8%	-4.7%	356	2.2	178	2.4
15N	WILLOW LANE	69	Willow Lane, Truro	...	...	...	...	...	...	1.7%	1.4%	1.1%	0.7%	0.4%	498	10.6	447	11.0

Note: This table does not imply that the indicated size of generator can be interconnected at the bus listed.
All interconnections are subject to System Impact Studies.

2014 Transmission Bus
Loss Factor and Short Circuit Level Data

				Incremental Locational Loss Factors											Short Circuit Level			
Station ID	NAME	kV	LOCATION	110 MW	100 MW	90 MW	80 MW	70 MW	60 MW	50 MW	40 MW	30 MW	20 MW	10 MW	Maximum (MVA)	X/R Ratio	Minimum (MVA)	X/R Ratio
15S	WATERFORD	69	#16 Substation, New Waterford	...	...	...	...	...	...	12.8%	12.3%	11.8%	11.2%	10.7%	416	3.4	345	3.9
15V	SISSIBOO	69	Sissiboo Falls	...	...	...	...	...	...	5.1%	3.0%	0.8%	-2.5%	-5.7%	322	2.2	166	2.1
16N	STEWIAKE	69	Stewiacke	...	...	...	...	...	...	6.5%	5.5%	4.4%	3.3%	2.2%	228	4.0	217	4.2
16V	WEYMOUTH	69	Weymouth Mills	...	...	...	...	...	...	6.9%	4.3%	2.7%	-1.3%	-5.6%	265	2.1	144	1.9
16W	HEBRON	69	Hebron	...	...	...	...	...	...	-6.1%	-7.4%	-8.6%	-9.9%	-11.4%	352	3.2	223	3.8
17N	BROWNELL	69	Brownell Ave., Amherst	...	...	...	...	...	...	5.9%	4.6%	3.4%	2.0%	0.7%	281	6.3	275	6.5
17V	ST CROIX	69	St. Croix	...	...	...	...	...	...	-0.7%	-0.8%	-1.0%	-1.2%	-1.4%	809	11.9	607	13.3
18V	BURLINGTON	69	Upper Burlington	...	...	...	...	...	...	3.5%	2.4%	1.2%	0.0%	-1.3%	363	1.6	321	1.9
199H	TRAFALGAR	69	Trafalgar	...	...	...	...	...	...	8.0%	6.5%	4.9%	3.2%	1.5%	227	3.6	199	3.5
199W	EAST BRIDGEWATER	69	Oakhill (east of Bridgewater)	...	...	...	...	...	...	-0.4%	-1.1%	-1.8%	-2.4%	-3.3%	441	7.9	357	8.8
19C	CANSO	69	Canso	...	...	...	...	...	...	28.7%	23.0%	17.7%	12.2%	5.8%	57	2.1	54	2.1
19W	ARGYLE	69	Glenwood - Central Argyle, Yar.	...	...	...	...	...	...	N/A	N/A	N/A	-9.9%	-11.6%	329	4.7	192	4.4
1N	ONSLOWA	69	Onslow	...	...	...	...	...	...	3.0%	2.9%	2.8%	2.6%	2.5%	626	42.9	548	36.5
1N	ONSLOW6B	69	Onslow	...	...	...	...	...	...	2.5%	2.3%	2.2%	2.0%	1.9%	624	43.0	546	36.6
1S	SEABOARD	69	Glace Bay	...	...	...	...	...	...	11.1%	10.6%	10.1%	9.6%	9.1%	619	3.8	473	4.6
1V	AVON	69	Smith's Corner	...	...	...	...	...	...	3.0%	1.8%	0.7%	-0.5%	-1.7%	319	2.4	281	2.6
20H	SPRYFIELD	69	Halifax	...	...	...	...	...	...	-1.6%	-2.1%	-2.6%	-3.1%	-3.7%	239	11.5	212	12.2
20N	PARKST	69	Park Street, Amherst	...	...	...	...	...	...	4.8%	3.8%	2.7%	1.7%	0.6%	296	8.0	288	8.3
20V	FIVE PT	69	Hantsport	...	...	...	...	...	...	-2.0%	-2.5%	-3.0%	-3.4%	-4.0%	528	4.1	425	4.8
20W	PUBNICO	69	Lower East Pubnico	...	...	...	...	...	...	N/A	N/A	N/A	N/A	-13.4%	235	5.1	130	3.7
21W	WOODS HBR	69	Lower Woods Harbour	...	...	...	...	...	...	N/A	N/A	N/A	N/A	-14.8%	185	4.4	112	3.6
22V	NEW MINAS	69	New Minas	...	...	...	...	...	...	-4.4%	-4.9%	-5.4%	-5.9%	-6.4%	551	4.1	429	4.7
22W	BARRINGTON	69	Barrington Passage	...	...	...	...	...	...	N/A	N/A	N/A	N/A	-16.2%	153	3.6	99	3.2
23H	ROCKINGHAM	69	Meadowlark Cres., Bridgeview	...	...	...	...	...	...	-0.5%	-0.8%	-1.2%	-1.5%	-1.8%	551	5.8	450	6.6
23W	CLYDE RIVER	69	Clyde River	...	...	...	...	...	...	1.4%	-0.5%	-2.6%	-4.7%	-7.1%	158	2.9	138	3.2
24C	DICKIE BROOK	69	West Cook's Cove	...	...	...	...	...	...	17.5%	14.2%	11.0%	7.4%	3.6%	88	3.7	81	3.6
25W	SHELBURNE	69	Ohio Road at Shelburne	...	...	...	...	...	...	-2.7%	-3.8%	-4.9%	-6.0%	-7.1%	254	4.4	206	4.9
2S	V.J.	69	Victoria Junction	...	...	...	...	...	...	11.6%	11.4%	11.3%	11.1%	10.9%	1284	13.9	778	12.8
30N	MACCAN	69	Maccan	...	...	...	...	...	...	3.1%	2.5%	1.9%	1.3%	0.7%	365	16.1	354	17.1
30W	SOURIQUOIS	69	Shelburne (East of)	...	...	...	...	...	...	-3.2%	-4.0%	-4.9%	-5.9%	-6.8%	280	5.0	222	5.6
34H	GEIZERS	69	Highway 102 at Dunbrack St	...	...	...	...	...	...	-0.8%	-1.1%	-1.4%	-1.6%	-1.9%	267	20.3	234	20.8
36V	HILLATON	69	Hillaton	...	...	...	...	...	...	-2.5%	-3.5%	-4.6%	-5.7%	-6.9%	359	3.0	303	3.3
36W	EAST GREEN HBR	69	Green Harbour - Lydgate	...	...	...	...	...	...	-0.6%	-1.8%	-3.0%	-4.2%	-5.7%	252	3.0	204	3.6
37N	PARSBORO	69	Parrsboro	...	...	...	...	...	...	5.5%	4.2%	3.0%	1.7%	0.4%	165	6.9	162	7.0
37W	LOCKPORT	69	Lockeport	...	...	...	...	...	...	0.7%	-0.7%	-2.2%	-3.7%	-5.5%	217	2.8	180	3.2
3N	OXFORD	69	Oxford Junction	...	...	...	...	...	...	3.1%	2.4%	1.6%	0.9%	0.0%	265	8.7	260	9.0
3S	GANNON RD	69	North Sydney	...	...	...	...	...	...	12.6%	12.2%	11.9%	11.4%	11.2%	385	11.4	319	10.8
3V	BLACK RIVER	69	White Rock	...	...	...	...	...	...	-3.8%	-4.1%	-4.4%	-4.8%	-5.1%	482	9.7	380	9.6
3W	BIG FALL	69	Mersey River	...	...	...	...	...	...	6.2%	5.3%	4.1%	3.1%	2.2%	427	3.9	249	3.8
40H	WOODLAWN	69	Mt. Edward Dr. Dartmouth	...	...	...	...	...	...	-0.4%	-0.5%	-0.7%	-0.8%	-1.0%	923	7.9	663	9.0
43V	CANAAN RD	69	White Rock	...	...	...	...	...	...	-4.1%	-4.4%	-4.7%	-5.0%	-5.3%	775	7.3	552	7.8
46W	BROAD RIVER	69	Broad River	...	...	...	...	...	...	1.4%	0.5%	-0.4%	-1.4%	-2.4%	348	2.9	254	3.8
48H	PENHORN	69	Portland St.,Dartmouth	...	...	...	...	...	...	-0.5%	-0.6%	-0.7%	-0.8%	-1.0%	1167	8.1	779	9.5

Note: This table does not imply that the indicated size of generator can be interconnected at the bus listed.
All interconnections are subject to System Impact Studies.

2014 Transmission Bus
Loss Factor and Short Circuit Level Data

Station ID	NAME	kV	LOCATION	110 MW	100 MW	90 MW	80 MW	70 MW	60 MW	50 MW	40 MW	30 MW	20 MW	10 MW	Maximum (MVA)	X/R Ratio	Minimum (MVA)	X/R Ratio
				Incremental Locational Loss Factors											Short Circuit Level			
48W	LIVERPOOL	69	Liverpool	...	...	...	...	...	...	1.5%	0.8%	0.2%	-0.5%	-1.2%	396	5.1	272	6.2
4C	LOCHABER	69	Antigonish	...	...	...	...	...	...	7.6%	7.2%	6.9%	6.4%	6.2%	152	44.1	142	46.1
4N	TATAMAGOUCHE	69	Tatamagouche	...	...	...	...	...	...	9.4%	7.9%	6.4%	4.8%	3.3%	171	3.7	165	3.8
4S	TOWNSEND	69	Townsend Street, Sydney	...	...	...	...	...	...	11.4%	11.1%	10.8%	10.5%	10.2%	893	4.6	616	5.7
4W	LOWER GR.BK	69	Mersey River	...	...	...	...	...	...	3.2%	2.5%	1.9%	1.2%	0.6%	502	5.1	299	5.5
50N	TRENTON	69	Trenton	...	...	...	...	...	...	-0.8%	-2.5%	-5.3%	-10.8%	-26.9%	1121	46.2	849	44.7
50V	KLONDIKE	69	Kentville	...	...	...	...	...	...	-3.5%	-4.7%	-6.0%	-7.3%	-8.8%	330	2.6	283	2.9
50W	MILTON	69	Milton	...	...	...	...	...	...	0.6%	0.2%	-0.2%	-0.6%	-0.9%	600	9.6	353	10.4
51V	TREMONT	69	Tremont - East Tremont	...	...	...	...	...	...	-4.2%	-4.7%	-5.1%	-5.5%	-6.0%	615	6.2	440	6.3
52V	BERWICK	69	Berwick	...	...	...	...	...	...	-4.0%	-4.8%	-5.7%	-6.7%	-7.6%	390	3.3	319	3.7
53N	NORTHERN PULP	69	Abercrombie	...	...	...	...	...	...	5.7%	5.3%	4.8%	4.3%	3.9%	652	6.0	513	5.9
54H	MAPLE ST	69	Maple Street, Dartmouth	...	...	...	...	...	...	-0.3%	-0.4%	-0.5%	-0.6%	-0.7%	1457	10.5	899	11.8
54N	ABERCROMIE	69	Abercrombie	...	...	...	...	...	...	5.4%	5.0%	4.7%	4.3%	4.0%	723	7.4	567	7.5
55N	PICTOU	69	Pictou	...	...	...	...	...	...	6.1%	5.4%	4.8%	4.0%	3.4%	445	3.4	381	3.7
55V	WATERVILLE	69	Waterville	...	...	...	...	...	...	-4.9%	-5.6%	-6.4%	-7.2%	-8.1%	412	3.7	336	4.1
56N	HALIBURTON	69	Haliburton	...	...	...	...	...	...	5.6%	5.0%	4.5%	3.9%	3.4%	531	4.1	443	4.4
57C	SALMON R	69	Salmon River Lake	...	...	...	...	...	...	12.6%	10.3%	8.2%	5.9%	3.5%	99	4.8	92	4.7
57S	ALBERT B	69	Hwy. 22 at Horn's Road	...	...	...	...	...	...	15.0%	13.4%	11.7%	9.9%	8.0%	241	1.7	217	2.0
57W	CALEDONIA	69	Caledonia	...	...	...	...	...	...	7.4%	5.3%	3.2%	0.9%	-1.5%	234	1.7	165	2.1
58C	SW MARGAREE	69	Southwest Margaree	...	...	...	...	...	...	15.0%	13.3%	11.6%	9.8%	8.1%	122	4.3	115	4.4
58H	IMPERIAL	69	Imperoyal, Dartmouth	...	...	...	...	...	...	-0.6%	-0.7%	-0.9%	-1.0%	-1.2%	983	7.3	693	8.6
5V	LUMSDEN	69	Newtonville (SSE White Rock)	...	...	...	...	...	...	-3.2%	-3.6%	-4.0%	-4.3%	-4.8%	632	5.0	469	5.5
62H	ALBRO	69	Albro Lake Road, Dartmouth	...	...	...	...	...	...	0.1%	0.0%	-0.1%	-0.1%	-0.2%	1541	10.7	930	12.0
62N	BRIDGE AV	69	Bridge Ave., Stellarton	...	...	...	...	...	...	4.5%	3.9%	3.4%	2.7%	2.2%	468	5.2	413	5.8
62N	STELLARTON	69	Bridge Ave., Stellarton	...	...	...	...	...	...	6.2%	5.7%	5.1%	4.5%	4.0%	606	4.0	512	4.5
63V	KINGSTON	69	Kingston	...	...	...	...	...	...	-4.0%	-4.7%	-5.3%	-5.9%	-6.7%	468	4.2	359	4.5
64V	GREENWOOD	69	Greenwood Village	...	...	...	...	...	...	-4.2%	-4.7%	-5.3%	-5.9%	-6.5%	531	4.6	395	4.9
65V	MIDDLETON	69	Middleton (1 km SE)	...	...	...	...	...	...	-3.2%	-3.9%	-4.7%	-5.6%	-6.5%	398	4.7	289	4.6
67C	WHYCOGO	69	Whycocomagh	...	...	...	...	...	...	12.3%	11.8%	11.3%	10.8%	10.3%	232	8.2	207	8.2
6N	BLACK.RIVER	69	Springhill	...	...	...	...	...	...	3.3%	2.6%	1.8%	1.1%	0.3%	324	6.6	316	6.9
6S	TERRACE ST	69	Terrace Street, Sydney	...	...	...	...	...	...	11.3%	11.0%	10.6%	10.3%	10.0%	713	7.0	524	7.8
6S	TERR. EXT	69	Terrace Street, Sydney	...	...	...	...	...	...	11.2%	10.9%	10.6%	10.3%	10.0%	776	7.4	557	8.3
6V	HOLLOW B	69	Newtonville (SSE White Rock)	...	...	...	...	...	...	-1.8%	-2.5%	-3.0%	-3.6%	-4.3%	502	3.6	389	3.9
70V	BRIDGETOWN	69	Bridgetown	...	...	...	...	...	...	-1.3%	-2.5%	-3.8%	-5.0%	-6.3%	332	4.6	214	3.9
70W	HIGH STREET	69	High Street, Bridgewater	...	...	...	...	...	...	-2.1%	-2.8%	-3.5%	-4.3%	-5.1%	453	8.4	365	9.2
73W	AUBURNDALE	69	Auburndale	...	...	...	...	...	...	-1.5%	-1.8%	-2.0%	-2.1%	-2.5%	548	15.7	424	15.8
74N	SPRINGHILL	69	East of Springhill Town	...	...	...	...	...	...	2.3%	1.9%	1.4%	0.9%	0.4%	404	15.9	391	16.9
74V	CORNWALLIS	69	Cornwallis	...	...	...	...	...	...	2.9%	1.0%	-1.1%	-3.2%	-5.4%	367	2.8	183	2.6
75N	DOMTAR	69	Nappan	...	...	...	...	...	...	5.1%	4.1%	3.1%	2.1%	1.1%	275	5.1	269	5.3
75W	WESTHAVER	69	Blockhouse - Maitland	...	...	...	...	...	...	-1.0%	-1.3%	-1.5%	-1.8%	-2.2%	355	23.6	298	22.0
76V	MAITLAND	69	Maitland Bridge	...	...	...	...	...	...	7.1%	4.9%	2.6%	0.3%	-2.2%	229	1.7	158	2.1
76W	MAHONE T	69	Fauxbourg (Mahone Bay)	...	...	...	...	...	...	-0.8%	-1.5%	-2.2%	-2.9%	-3.8%	299	6.1	258	6.6
76W	MAHONE BAR	69	Mahone Bay	...	...	...	...	...	...	-0.4%	-1.2%	-1.9%	-2.8%	-3.7%	287	5.2	249	5.7

Note: This table does not imply that the indicated size of generator can be interconnected at the bus listed.
All interconnections are subject to System Impact Studies.

2014 Transmission Bus
Loss Factor and Short Circuit Level Data

				Incremental Locational Loss Factors											Short Circuit Level			
Station ID	NAME	kV	LOCATION	110 MW	100 MW	90 MW	80 MW	70 MW	60 MW	50 MW	40 MW	30 MW	20 MW	10 MW	Maximum (MVA)	X/R Ratio	Minimum (MVA)	X/R Ratio
77V	CONWAY	69	Digby	...	...	...	...	...	...	4.9%	2.3%	-0.2%	-3.0%	-5.5%	383	3.2	146	2.1
78W	MARTINS	69	Martins Brook (North West)	...	...	...	...	...	...	-0.4%	-1.6%	-2.7%	-4.0%	-5.4%	252	3.7	223	4.0
79V	3 MILE PLAIN	69	Plains	...	...	...	...	...	...	-0.9%	-1.3%	-1.8%	-2.3%	-2.8%	650	5.9	511	6.9
79W	LUN SWST	69	Green St. Lunenberg	...	...	...	...	...	...	-0.1%	-1.4%	-2.8%	-4.2%	-5.9%	237	3.3	211	3.6
7N	PUGWASH	69	Pugwash	...	...	...	...	...	...	5.1%	3.9%	2.6%	1.4%	0.0%	154	6.4	152	6.5
7W	HARMONY	69	Harmony Mills	...	...	...	...	...	...	7.3%	5.2%	3.0%	0.7%	-1.8%	230	1.7	162	2.1
80W	INDIAN PATH	69	Indian path	...	...	...	...	...	...	1.6%	-0.1%	-2.0%	-4.0%	-6.3%	185	2.8	169	3.0
81S	RESERVE	69	Reserve Street, Glace Bay	...	...	...	...	...	...	10.8%	10.4%	9.9%	9.5%	9.0%	636	4.3	482	5.1
81V	ANNAPOLIS	69	Annapolis River Causeway	...	...	...	...	...	...	0.1%	-1.4%	-2.8%	-4.4%	-5.9%	396	4.9	203	3.4
81W	LUNENBUR	69	Lunenburg	...	...	...	...	...	...	0.3%	-1.2%	-2.7%	-4.2%	-6.0%	229	3.1	205	3.4
82S	WHITNEY PIER	69	Lingan Road, Sydney	...	...	...	...	...	...	12.2%	11.9%	11.5%	11.1%	10.8%	705	5.0	520	5.8
82W	NATIONAL SEA	69	Blue Rocks	...	...	...	...	...	...	1.5%	-0.2%	-1.9%	-3.7%	-5.8%	208	2.7	188	3.0
83V	WOLFVILLE	69	Wolfville	...	...	...	...	...	...	-3.1%	-3.6%	-4.1%	-4.6%	-5.2%	515	4.1	412	4.8
84S	VJ DISTRIBUTION	69	Victoria Junction	...	...	...	...	...	...	11.6%	11.4%	11.2%	11.0%	10.8%	1214	10.1	751	10.6
84W	ROBINSONS	69	Robinson Corner	...	...	...	...	...	...	2.3%	0.9%	-0.5%	-1.9%	-3.5%	164	4.8	153	5.1
85W	EAST RIVER	69	East River	...	...	...	...	...	...	-0.1%	-0.7%	-1.4%	-2.0%	-2.7%	218	10.3	199	10.6
85W	CANEXEL	69	East River	...	...	...	...	...	...	0.5%	-0.3%	-1.0%	-1.8%	-2.7%	202	8.5	186	8.8
86W	MIDRIVSW	69	3.7 km North of East River	...	...	...	...	...	...	1.0%	0.0%	-1.0%	-2.0%	-3.1%	180	6.9	167	7.2
87W	HUBBARDS	69	Hubbards, Mill Lake Road	...	...	...	...	...	...	-0.6%	-1.1%	-1.5%	-1.9%	-2.4%	251	18.1	226	17.7
88H	UPPER. MUSQ	69	Upper Musquodoboit	...	...	...	...	...	...	13.8%	10.7%	7.3%	3.6%	-0.7%	119	2.0	111	2.1
88W	PLEASANT ST	69	Pleasant St., Yarmouth	...	...	...	...	...	...	-4.8%	-6.5%	-8.3%	-10.2%	-12.4%	288	2.2	196	2.8
88W	PEASANT_B5	69	Pleasant St., Yarmouth	...	...	...	...	...	...	-5.4%	-6.9%	-8.5%	-10.2%	-12.2%	288	2.2	196	2.8
89N	NUTTBY	69	Co.	...	...	...	...	...	...	7.7%	6.8%	6.0%	5.0%	4.2%	268	4.5	253	4.7
90H	SACKVILLE	69	Bedford, Lower Sackville	...	...	...	...	...	...	-0.6%	-0.7%	-0.8%	-0.9%	-1.0%	1192	12.3	800	13.3
91H	TUFTCOVE	69	Tufts Cove, Dartmouth	...	...	...	...	...	...	0.0%	0.0%	0.0%	-0.1%	-0.1%	2181	38.9	1130	21.5
91W	MIDDLEFIELD	69	Middlefield	...	...	...	...	...	...	7.0%	5.4%	3.9%	2.3%	0.6%	296	2.1	199	2.5
92V	MICH WAT	69	Waterville - Cambridge	...	...	...	...	...	...	-4.7%	-5.4%	-6.1%	-6.8%	-7.5%	446	4.1	359	4.6
92W	CARLETON	69	Carleton, Yarmouth	...	...	...	...	...	...	-2.4%	-3.9%	-5.4%	-7.0%	-8.7%	343	2.2	219	2.9
93V	SAULNIER	69	Saulnierville	...	...	...	...	...	...	8.1%	4.9%	1.6%	-1.5%	-6.5%	169	2.7	110	2.2
95H	MALAY FALLS	69	Malay Falls	...	...	...	...	...	...	12.7%	9.8%	7.1%	4.3%	1.2%	143	4.0	119	3.6
96H	RUTH FALLS	69	East River, Sheet Harbour	...	...	...	...	...	...	14.6%	11.4%	8.2%	4.8%	1.0%	133	3.7	110	3.2
96S	DONKIN RD	69	Donkin or Schooner Pond	...	...	...	...	...	...	11.4%	10.8%	10.2%	9.6%	9.1%	567	3.3	442	4.0
98V	GULLIVERS	69	Digby Neck	...	...	...	...	...	...	8.6%	5.6%	2.6%	-0.5%	-3.7%	392	5.7	118	2.1
99H	FARRELL	69	Farrell St., Dartmouth	...	...	...	...	...	...	0.0%	0.0%	-0.1%	-0.1%	-0.2%	2109	30.7	1111	20.2
99W	BRIDGEWATER	69	Bridgewater	...	...	...	...	...	...	-1.4%	-1.5%	-1.7%	-1.8%	-2.1%	587	24.6	447	22.0
9C	ABERDEEN	69	Aberdeen	...	...	...	...	...	...	14.7%	13.7%	12.7%	11.7%	10.7%	179	4.7	164	4.9
9W	TUSKET B51	69	Tusket Falls	...	...	...	...	...	...	-6.3%	-7.1%	-7.8%	-8.6%	-9.6%	543	6.3	286	6.1
9W	Tusket B53	69	Tusket Falls	...	...	...	...	...	...	-6.3%	-7.1%	-7.8%	-8.6%	-9.6%	543	6.3	286	6.1

Note: This table does not imply that the indicated size of generator can be interconnected at the bus listed.
All interconnections are subject to System Impact Studies.

NON-CONFIDENTIAL

Request IR-2:

Please provide any estimates available to NS Power of the "system dispatch, load following and operating reserve effects" of renewable by energy source (Appendix 16 at 30):

(a) Wind
(b) Solar
(c) Biomass
(d) Tidal
(e) Small hydro

Response IR-2:

The effects of all system resources, including wind, solar, biomass, tidal and small hydro, on all system operating parameters, including system dispatch, load following and operating reserve, are considered in the system dispatch optimization simulation simultaneously. The analysis of the effects of individual resources on specific system operating parameters is not available.

For more information, refer to the 2013 GE Energy Consulting report, *Nova Scotia Renewable Energy Integration Study*, which was provided by NS Power in the 2014 Annual Capital Expenditure Plan proceeding. It can be found on the NSUARB website under Matter Number M05998, Exhibit N-3, as NSUARB IR-19 Attachment 1.

NON-CONFIDENTIAL

Request IR-3:

Please explain whether NS Power believes that all types of renewables used in RtR transaction should pay for the same level of system dispatch, load following and operating reserve, and if so, why.

Response IR-3:

These services are all Ancillary Services provided under the OATT and are required in order to ensure reliable service to customers. As a result, in accordance with the FERC 888 pro-forma tariff and subsequent practice, these costs have been allocated and charged according to customer load. This is unchanged from the requirements under the OATT.

NS Power has seen no cause for any revision of this industry accepted practice for the purpose of the RtR market.

NON-CONFIDENTIAL

Request IR-4:

Reference: Distribution Losses

Please reconcile the 7.7% distribution losses in Appendix 13 (e.g., page 136) and Appendix 14, pp. 4–6, with the much lower average distribution losses reported in the EBS tab of the Appendix 24 spreadsheet.

Response IR-4:

The distribution losses of 7.7% were used by NS Power in the illustrative bill calculations in response to Scotian WindFields Inc. DR-1 (**Appendix 14**) and is consistent with that applied in **Appendix 24**. The bill calculations in Appendix 14 are for the month of February and use distribution losses of 7.7% from that month. The same distribution line losses are used in bill calculations for the month of February in the EBS tab of Appendix 24. The average line losses of 6.2% from the EBS tab represent an annual average.

NON-CONFIDENTIAL

Request IR-5:

Reference: Spill and Top-Up Rates

Please provide all workpapers (including the input and output from the Plexos runs) supporting the following values in Appendix 19A:

(a) $13,052,400 for "Avoided Costs of departing customer Load before taking energy balancing service from NS Power."

(b) $11,541,300 for "Avoided Costs of departing customer Load after taking energy balancing service from NS Power."

Response IR-5:

(a-b) The calculation of the avoided costs above is provided in the response to Multeese DR-25, included in Appendix 13B. It is predicated on the Plexos run results included in Attachment 1 to **SBA IR-8 part (a)**.

NON-CONFIDENTIAL

Request IR-6:

Reference: Spill and Top-Up Rates

Please provide a breakdown of the avoided costs by month and by time of day, if available.

Response IR-6:

The avoided costs were calculated on an annual basis from the model results. Time of day avoided costs are not available from the simulation output.

NON-CONFIDENTIAL

Request IR-7:

Reference: Spill and Top-Up Rates

Please identify the period for which Appendix 19A estimates the costs of the EBS.

Response IR-7:

Please refer to **SBA IR-8 part (b)**.

NON-CONFIDENTIAL

Request IR-8:

Reference: Spill and Top-Up Rates

Please explain why NS Power chose to present only annual energy charges for customers who will have interval meters and can be charged by month and time of day.

Response IR-8:

Please refer to **Section 5.5.2** of the Cary Report (**Appendix 16**). In brief, the Company notes as follows:

- The avoided cost at any time is highly dependent on other variable generation production, with which the RtR generation production may be correlated.
- The pattern of such RtR generation is not pre-determinable and as a result, cannot be used as a basis for determining hourly rate differentials.
- NS Power cannot therefore use pre-determined time of day or seasonal rates to recover all the losses that would otherwise arise from differences in marginal cost at time of spill and marginal cost at time of top-up.
- Given a need for a spread between top-up and spill rates, there is no benefit of the additional complexity that would arise from superimposing such spread on rates that vary on an hourly or seasonal basis.

The use of *ex-post* calculated hourly incremental costs would add significant further uncertainty, administration and cost to the settlement process and was rejected for those reasons.

The selected approach is consistent with the annual basis for the Bundled Service rates against which RtR service competes, and avoids the need for further complexity to address variable top-up rates in the determination of the Renewable to Retail Market Transition Tariff energy charges.

NON-CONFIDENTIAL

Request IR-9:

Reference: Spill and Top-Up Rates

Please enumerate the categories of costs that are assumed to be avoidable in the Plexos runs. In particular, do the Plexos runs reflect:

(a) Variable non-fuel O&M, including the effect of energy load on maintenance intervals.

(b) The effect of energy loads and renewable capacity on NS Power's ability to mothball units during the summer.

(c) The effect of energy loads and renewable capacity on NS Power's ability to retire coal plants earlier than currently planned.

(d) The effect of energy loads and renewable capacity on the need for new generation.

(e) Variable interim capital additions, including environmental retrofits.

Response IR-9:

The categories of costs assumed to be avoided in the Plexos runs are: fuel costs, unit start costs, variable operating and maintenance charges based on the generation by each unit, abatement costs, and market purchases.

The avoided costs runs did not reflect the other effects described in parts (a–e).

NON-CONFIDENTIAL

Request IR-10:

Does NS Power believe that the avoided costs for the RtR should incorporate savings that depend on renewable energy contributions for several years, or on multiple renewable projects? If not, please explain why.

Response IR-10:

In the context of the Energy Balancing Service (EBS) Tariff, the avoided costs are those related to energy production. These avoided costs are mostly fuel-related and will vary from year to year. The EBS Tariff elements related to avoided cost will therefore be subject to annual adjustment.

In the context of the Renewable to Retail Market Transition Tariff, some cost mitigation may be annual in nature, but any ability to avoid or defer investment would be considered in the context of longer time horizons which may explicitly consider cumulative effects of multiple RtR projects.

NON-CONFIDENTIAL

Request IR-11:

Does NS Power agree that, once the transmission ties to New Brunswick are reinforced, the benefits of spill and the cost of top-up will include changes in sales over those lines to New Brunswick and New England? If not, please explain why.

Response IR-11:

Energy flows on the tie are currently limited in part by system constraints in NB Power's service territory. In the hypothetical scenario referenced, and to the extent these system constraints could be alleviated, an increase in exports from and imports to Nova Scotia may be possible. The proposed annually adjusted approach to determination of the top-up and spill rates enables timely alignment of Energy Balancing Service Tariff rates with changing market conditions.

NON-CONFIDENTIAL

Request IR-12:

Do the proposed EBS rates reflect the relative contribution of various types of renewable generation to ramping costs and operating reserves?

(a) If not, would such consideration be appropriate in setting the EBS rates?

Response IR-12:

No. The contribution of various types of renewable generation to ramping costs is not considered in the system dispatch optimization model. The effect of incremental renewable energy additions on steam unit ramping costs is negligible compared to the cost of fuel. Further, while operating reserve provision is a part of the Plexos system dispatch optimization, intermittent variable renewable resources are not contributors to the operating reserve provision in the dispatch optimization.

NON-CONFIDENTIAL

Request IR-13:

For Appendix 19A, please provide the number of GWh of the following transactions assumed for the RtR Plexos runs:

(a) spill GWh
(b) top-off GWh

Response IR-13:

Plexos system dispatch optimization simulations optimize system dispatch by taking into account all system resources and demand. Top-up and spill amounts are not a direct result of the Plexos simulation. Plexos reflects conservation of energy between supply and demand, therefore top-up and spill amounts are matched in the annual outcome. Please refer also to **CA IR-17.**

NON-CONFIDENTIAL

Request IR-14:

Please provide the characteristics assumed for the "effect of 3rd party renewable generation under no curtailment assumption" in Appendix 19A, including at least the following:

(a) The type of renewable generation (e.g., small hydro, wind, solar, tidal).

(b) The monthly, daily and hourly generation pattern assumed, and the basis for those assumptions.

(c) Forecasting accuracy for commitment planning, for the renewable generator and other resources.

Response IR-14:

(a) The renewable generation was modeled with the characteristics of wind generation.

(b) The generation pattern of the third party renewable generation was an hourly shape with a profile based on NS Power historical hourly wind generation, fitted using the energy of an equivalent 50 MW wind farm.

(c) Plexos simulation unit commitment optimization is based on a matched wind and load hourly shape data set with no forecasting error.

NON-CONFIDENTIAL

Request IR-15:

Please restate the credits against the total energy-related costs in cell G29 of Appendix 19A in ¢/kWh.

(a) Please confirm that these credits total less than the estimated value of avoided costs with or without EBS (cells F6 and F8).

(b) Please confirm that the sum of the avoided-cost rate and the fixed-cost rate would exceed the energy charge for full-service customers.

(c) Please explain why NS Power should charge more for energy provided to RtR customer than to full-service customers.

Response IR-15:

The restated credits, based on the 2014 Cost of Service Study, are as follows:

	Costs in thousands of $'s	Unit Costs in cents per kWh
All energy-related generation costs	$753,049	7.920
Less		
Plant Fuel Cost	$367,943	3.870
Purchased Power regular	$507	0.005
Purchased Power biomass	$11,595	0.122
Purchased Wind Power	$59,982	0.631
Imports	$217	0.002
Export Revenues	-$1,826	(0.019)
Subtoal Fuel-related	$438,418	4.611
Energy-related fixed costs	$314,631	3.309

(a) Confirmed. However, NS Power notes, as provided in the response to **SBA IR-8**, the avoided cost calculations were derived using multiple runs over a ten year period from 2018 to 2027 based on the 2014 IRP preferred resource plan. Going forward, for the purpose of the Annually Adjusted Rate setting process, the Company intends to use calculations based on a single test year. The table below illustrates that individual test year results can vary.

Source	**Avoided Cost of 25 MW decrement (c/kWh)**	**Average fuel-related cost embedded in base cost rates (c/kWh)**	**% Variance from average fuel cost**	**Outcome**
2014 LF Rate	4.55	4.611	-1%	Lower
2015 LF Rate	5.08	4.611	10%	Higher
2016 LF Rate (Preliminary Estimate from 2016 BCF)	4.53	4.915	-8%	Lower

(b) Energy charges for full service customers billed under most rate classes are greater than the sum of the avoided fuel and fixed unit costs of 7.92 cents per kWh. For example, the current energy charge for the Domestic class is 14.251 cents per kWh and for the Large General class it is 8.029 cents per kWh. The Company notes, however, that energy charges in rate classes that do not include demand charges are designed to recover both the energy and demand related costs.

(c) The proposed approach to determination of the fixed cost component of the EBS charge is based on fully allocated costs as is the case under the full service rates. However, the fuel cost component is based on incremental fuel costs as opposed to average fuel costs applicable under the bundled service rates. As can be seen from parts (a) and (b) NS Power would not always charge more for energy provided to the RtR customers than to full service customers.

The top-up and spill energies are typified by uncertainty in terms of their annual levels and hourly patterns. They are far less predictable than loads served under the bundled service rate classes. Due to variability in the spill and top-up energies, the Company must often ramp up and down its dispatchable generation forcing it to operate under suboptimal heat curve conditions. This results in higher unit fuel costs which are attributable to the characteristics of the RtR market. NS Power energy provided under the top-up service and displaced under the spill from the LRS's generators comes solely from dispatchable fossil fuel-fired or hydro generators. The more expensive must-run renewable purchases from IPPs and COMFIT are not affected by this balancing service.

NON-CONFIDENTIAL

Request IR-16:

Reference Appendix 15 at 11:

> **This Annual Energy Cost Adjustment is deducted from the base energy rate to get the net energy charge under the tariff. If the average fuel cost were to exceed the avoided cost, this Energy Charge Adjustment would become an addition to the net energy charge under the tariff.**

Since NS Power's estimate of the avoided costs is higher than the average fuel cost, why doesn't NS Power subtract that difference from the fixed cost energy rate?

Response IR-16:

To provide an indication of a longer-term pricing level under the top-up and spill rates, the Company estimated annual avoided costs based on multiple Plexos runs over a ten year period from 2018 to 2027 taking advantage of the 2014 IRP cost information on the regulatory record. Going forward, however, commencing with the 2017 EBS Tariff rate submission, the Company proposes to estimate avoided costs for a single test year analysis, consistent with the treatment of fuel costs of other Annually Adjusted Rates. As indicated in the response to **CA IR-15**, under the single test year approach the annual marginal costs are expected to fluctuate closely around the average system fuel cost. The adjustment is expected to be minor and close to zero on the average in the foreseeable future. In view of this, no estimate of this adjustment was included in the RTT in the Application.

NON-CONFIDENTIAL

Request IR-17:

Please provide the basis for assuming that "top-up energy accounts for 50% of the total energy consumed in the RtR market" (Appendix 19A).

Response IR-17:

Absent forecast information on types and numbers of future RtR customers as well as types of future renewable generation that would make it possible for the Company to develop hourly load and generation profiles, the Company assumed hourly fluctuations in top-up and spill energy to be random with zero percent correlation and the same factors for load and capacity, which yields the 50 percent overlap factor in top-up deliveries and customer load.[1] From a statistical outcome perspective this represents the safest approach to minimize swings in over- or under-recovery of energy balancing costs. Going forward, as the Company accumulates historic data on hourly energy balancing services and gathers information on future service potential, the Company will provide a forecast of this factor. Please refer to the following Data Requests for more details:

- Multeese DR-25, **Appendix 13B**
- Multeese DR-30, **Appendix 13**, pages 113-115
- Multeese DR-35, **Appendix 13**, pages 124-128

[1] The Company realizes that in actuality the RtR customer load factors will likely be higher than capacity factors of wind generation, having the reducing effect on the overlap factor, and that there may be some measure of a positive correlation in fluctuations of load and generation, having an offsetting increasing effect on the overlap factor.

NON-CONFIDENTIAL

Request IR-18:

Please provide the ratio of top-up energy to total consumption for a typical residential RtR customer served by:

(a) **A typical NS Power wind resource.**

(b) **A biomass resource that operates with the same hourly pattern as:**

- **(i)** **Port Hawkesbury Biomass**
- **(ii)** **Brooklyn Power**

(c) **A small hydro resource that operates with the same hourly pattern as:**

- **(i)** **Black River Hydro**
- **(ii)** **The Lequille Hydro system**

(d) **A tidal project that operates with the same hourly pattern as Annapolis Tidal Power.**

Response IR-18:

(a) The ratio of top-up energy to total consumption for a residential RtR customer served by wind in the Plexos modeling was approximately thirty percent.

(b–d) The requested analysis was not completed as part of this Application.

NON-CONFIDENTIAL

Request IR-19:

Please provide the derivation of the excess spill discount.

(a) If the spill rate is properly set, at the value to the system of backing down NS Power generation, why would any discount be appropriate for additional energy provided in excess of RtR customer requirements?

Response IR-19:

The Company did not undertake a cost study in support of the proposed excess spill discount rates. The rates were set in a manner that directionally aligns with the anticipated decline in fuel cost savings with increases in excess spill and also provides an incentive to the LRS to match, to the maximum extent possible, generation with RtR load. Please refer to **ECI IR-7** for more details.

(a) Given the declining scale of the excess spill discounts, a generic flat spill rate, applicable on a monthly and year-end basis, would be lower than the one currently proposed for the monthly compensation along with separate excess spill discount rates. The lower flat spill rate would disadvantage those LRSs that come close to matching their generation to their load.

NON-CONFIDENTIAL

Request IR-20:

Please provide the hourly generation for each renewable resource of the NS Power system with hourly metering (including purchases and NS Power hydro, wind and biomass resources), for each hour since January 2010.

Response IR-20:

The data requested was not used in the preparation of this Application. The tariffs were prepared using average monthly system dispatch optimization data outputs.

Historical hourly generation was not used by the Plexos model to complete the analysis. Hydro generation is modeled in Plexos as monthly available energy with dispatch optimized within individual hydro system dispatch constraints. Wind generation is based on a 2014 hourly wind generation profile from which Plexos develops a fitted hourly wind generation shape based on forecasted monthly energy and maximum capacity of each wind resource. The Port Hawkesbury Biomass generation is modeled as must-run using constraints to enforce the legislated amount of energy produced. Energy purchases are not input directly into the model, but selected by a dispatch optimization algorithm economically, given the system conditions.

NON-CONFIDENTIAL

Request IR-21:

Please provide any data available to NS Power on its hourly marginal energy costs, for any available periods since January 2010.

Response IR-21:

The requested analysis was not completed as part of this Application. Please refer to **CA IR-20**.

NON-CONFIDENTIAL

Request IR-22:

Please explain why Appendix 19A uses a transmission loss factor, rather than losses to the customer meter.

Response IR-22:

Appendix 19A is concerned with a determination of a generic energy-related energy charge applicable to LRS load estimated at a transmission service level. The charge is not specific to any bundled service rate class. The fixed cost portion of the rate is determined by dividing the total system energy-related fixed generation costs of $314,631,000 by the system energy requirement of 9,507,746 GWh at a transmission service level. The energy requirement was determined by applying an average system transmission loss factor of 3.2%, as used in the 2013 General Rate Application and Cost of Service Study proceedings, to the total energy requirement. Given that NS Power’s Cost of Service model provides for a uniform transmission loss factor for all distribution served customers, the proposed approach is the most effective way to estimate energy requirements at transmission level of these customers.

Request IR-23:

Please explain the difference between the 3.2% transmission loss factor used in Appendix 19A and the 2.28% transmission loss factor in Appendix 14A, note 2.

(a) Please provide the derivation of the 3.2% transmission loss factor used in Appendix 19A.

(b) Please provide the derivation of the 2.28% transmission loss factor used in Appendix 14A.

Response IR-23:

The 3.2% transmission loss factor identified in **Appendix 19A** is employed in the 2014 Cost of Service study. The 2.28% loss factor of **Appendix 14A** is the System Average Transmission Loss Factor applied to Network Integration Transmission System Load in accordance with Section 28.5 and Schedule 9 (paragraph 2) of the NSPI Open Access Transmission Tariff.

(a) The Cost of Service Transmission Loss Factor includes generator transformer losses and assumes delivery at distribution voltage levels, thereby including the losses of NSPI distribution substation transformers.

(b) The System Average Transmission Loss Factor is computed annually based on the hourly calculated transmission system losses from the previous calendar year. Actual system operational conditions for each hour of each month are imported into a model of the NS Power system (in the transmission system analysis program). The model calculates the transmission system losses for each hour. Network Integration Transmission Service requires that the transmission customer replace losses associated with transmission service, which does not include generator transformer losses or distribution substation transformer losses. As a result, the System Average Transmission Loss Factor is lower than the Cost of Service Transmission Loss Factor.

NON-CONFIDENTIAL

Request IR-24:

Reference: Forecasting Charges

Please provide the derivation of the charges for the "aggregate hourly scheduled or forecast quantity" (Appendix 12, p. 16), including:

(a) The rationale for a 10% threshold, rather than a higher or lower percentage.

(b) The rationale for charging 10% of marginal cost, rather than a higher or lower percentage.

(c) The rationale for using the average period system marginal cost for the billing month for computing the 10%, rather than the cost in the hours with the forecasting error.

Response IR-24:

The Company did not conduct a cost analysis in support of this proposal. Rather, the proposed approach builds on the pricing construct already approved for use under Schedule 4 of the OATT. This approach is consistent with the Company's objective to leverage, to the extent practical, the existing rate design structures to keep the proposed rate changes simple.

(a) The 10 percent threshold is currently approved for use for non-dispatchable generation energy imbalance services under Schedule 4.

(b) The 10 percent threshold for adjustment to hourly marginal costs, applicable to all deviations from schedule outside of the +/- 10 percent deviation band, is currently approved for use for non-dispatchable generation energy imbalance services under Schedule 4.

NON-CONFIDENTIAL

(c) In design of this component, the Company borrowed from a simplified treatment of hourly deviations within the deviation band as used for the pricing purposes of Load Energy Imbalance. Given the small scale renewable generation anticipated under the market and the fact that the purpose behind this schedule is to provide only an incentive for accurate forecasting and not to recover costs of balancing services, as these are accounted for under the Energy Balancing Service Tariff, this simplification is considered appropriate.[1]

[1] Assuming a purely random occurrence of negative and positive deviations outside the 10% band such that positive and negative imbalances net out to zero at the end of the billing period, a non-dispatchable generator should see very similar billing results under the hourly approach of schedule 4 and time of day period approach of schedule 4A.

NON-CONFIDENTIAL

Request IR-25:

Reference: Forecasting Charges

Considering NS Power's experience with forecasting wind output, and the greater base over which it conducts such forecast, why does NS Power propose to require the LRS to perform its own duplicative forecasting for wind generation, rather than NS Power assuming the responsibility for forecasting wind-plant output, other than equipment outages?

Response IR-25:

This provision is consistent with the requirements of the current Market Rules. Section 4.0 to 4.5 (**Appendix 25**, pages 88-99) covers scheduling. The proposed amendment to the Market Rules for Submission of Energy Schedules for the Renewable to Retail Market is in **Appendix 25** Section 3.6, on pages 93-94.

Each generator technology and location will have unique characteristics that will affect the generation forecast. The generator owner will be in the best position to provide the generator day-ahead forecast.

NON-CONFIDENTIAL

Request IR-26:

Reference: Transition Charges

Please provide the derivation of the RTT charges.

Response IR-26:

For derivation of the Renewable to Retail Market Transition Tariff charges please refer to:

- The Company's response to Multeese DR-29, included in Application **Appendix 13C,** which provides the derivation of the Standby Service Tariff charges, and

- Application **Appendix 19A**, which provides the derivation of the Energy Balancing Service Tariff charges.

For the explanation of why the same charges are used in the RTT tariff as in the EBS and SS tariffs please refer to **NSUARB IR-2**.

Request IR-27:

Reference: Transition Charges

Please explain the logic for charging a demand charge of $5.37/kW-month for an LRS serving customers in rate classes that do not have demand charges.

Response IR-27:

The charge determinant for the demand charge element of the Renewable to Retail Market Transition Tariff depends on the quantity and characteristics of the LRS's generation, and only in exceptional circumstances on the customer load. The generation is independent of the customer class(es) being served. There would be no reason to differentiate the charge basis according to customer class.

It should be noted in support that the energy charges to Bundled Service residential customers do include in effect the conversion of that $5.37/kW-month demand charge into an energy charge based on the relevant class load profile.

NON-CONFIDENTIAL

Request IR-28:

Reference: Transition Charges

Please explain why NS Power is proposing to charge the RTT demand charge on the "LRS's firm demand at the time of system coincident firm load peak in each month," rather than just the three winter months, or some other weighting of months.

Response IR-28:

The demand charge in the Renewable to Retail Market Transition Tariff is a reflection of the demand charge in the Standby Service Tariff.

Under a steady-state RtR market without migration of customers to and from RtR supply and among LRSs, it would be possible to utilise the three winter months as a basis for charges under both tariffs. The need to achieve fair cost recovery under circumstances where we can expect migration of customers, particularly during market growth, drives the use of equivalent annual peak demand derived from monthly coincident peaks.

NON-CONFIDENTIAL

Request IR-29:

Reference: Transition Charges

The derivation of the RTT demand charge appears to divide total demand-allocated generation costs by the sum of coincident loads in just three months (Appendix 13, at 112), but NS Power is proposing to apply this charge in all twelve months. If this does not result in a mismatch in costs and revenues and significant over-collection of costs, please explain why.

Response IR-29:

Appendix 13 at page 112 shows a three month average coincident peak of 1,811,990 kW.

The annual demand related fixed generation cost is $121,275,450.

The annual cost per kW of winter peak (measured as the average of the three winter month peaks) is $64.440/kW-year.

The monthly cost per kW of equivalent winter peak is $64.440/kW-year ÷ 12 = $5.370/kW-month.

Consider an example of an LRS with a customer portfolio with a three month average winter peak = 20 MW. The monthly peak in a summer month may be, say, 15 MW, which is factored up to 20 MW equivalent winter peak (using customer class factors as set out in the Standby Service Tariff, using for this example an assumed average factor of 1.333).

The NS Power annual demand related fixed generation cost requiring to be recovered is
20,000 kW x $64,440/kW-year = $1,288,800.

NON-CONFIDENTIAL

If the LRS self-supplies firm dependable capacity capable of supporting 8 MW of peak demand, then NS Power provides 12 MW of Standby Service x 12 months x $5.37/kW-month x 1,000 = $773,280.

The RTT demand charge, before mitigation, is 8 MW x 12 months x $5.37/kW-month x 1,000 = $515,520.

The total NS Power recovery before mitigation is $773,280 + $515.520 = $1,288,800.

This matches the cost to be recovered (before mitigation).

NON-CONFIDENTIAL

Request IR-30:

Reference Appendix 16 at 26:

> **Given that RtR customers are to be served with the same reliability as equivalent Bundled Service customers, the system adequacy requirement is mandatory in respect of those customer.**

Please explain how the RTT rate design reflects the contribution to system reliability of the renewable generator.

Response IR-30:

The services provided under the Energy Balancing Service Tariff, the Standby Service Tariff, the OATT and the Distribution Tariff are designed so that in combination they provide the same reliability as to equivalent Bundled Service customers.

The RTT does not contribute directly to system reliability, as its purpose is the recovery of embedded costs otherwise transferred to bundled service customers by LRS supply under the RtR market. The rate design does, however, result in charges that reflect the contribution to system reliability of the renewable generator.

For example, if an LRS serves customers whose equivalent winter peak demand is 20 MW, and its generation has a firm dependable capacity capable of supporting 8 MW, then NS Power would provide 12 MW of Standby Service. The RtR supply displaces 8 MW of NS Power service capability and the associated revenue. Unless and until NS Power can reduce its costs (e.g. by avoided or deferred investment) corresponding to that 8 MW, those costs are recovered from the LRS through the RTT. The RTT charges are thus reflective of the extent to which the LRS's self-supply of capacity to support system reliability has displaced utilisation and cost recovery on equivalent NS Power resources.

NON-CONFIDENTIAL

The energy charge under the RTT is similarly affected by the extent to which the LRS's supply of energy, excluding top-up, has displaced NS Power supply, and in particular the fixed costs recovered through that supply.

Request IR-31:

Reference: FAM Rates

If the FAM balance is positive, implying that fuel costs were higher than reflected in base rates, would it be appropriate to increase both the top-up and spill rates, since additional energy supplied by NS Power and additional energy supplied by the LRS would be more valuable than assumed in the original rate computation? If not, please explain why.

Response IR-31:

The Company has proposed that the treatment of fuel costs under the top-up and spill rates be consistent with that currently applicable to other Annually Adjusted Rates which are not subject to the FAM. Load billed under the AAR rates accounts for a small percentage of the total system load[1] and therefore has a limited effect on fuel costs of the FAM classes. Please refer to **SWEB IR-4** and **NSUARB IR-1** for further discussion of this subject matter.

[1] The forecast for 2016 kWh sales to AAR rate classes in the 2016 Base Cost of Fuel proceeding amounts to 25 GWh representing about 0.2% of the total system load.

NON-CONFIDENTIAL

Request IR-32:

Reference: Metering

Please describe the cost and capabilities of the interval meters that NS Power expects to install for RtR customers, disaggregated by class, voltage, or other capability as appropriate.

Response IR-32:

The meters will be capable of recording hourly demand and usage data and periodically uploading data to a central system using a data connection.

For an example of how present metering costs vary across customer classes, please refer to Application **Appendix 11A**, Cost of Service Model, Tab Exh 6.1, lines 1-34.

Specific meters suitable for residential, commercial, and industrial RtR installations have not yet been selected. In preparation for the implementation of the market opening, NS Power will conduct a procurement exercise to source the meters from competitive suppliers. At this point NS Power estimates that the installed cost for a new residential meter would be under $500. Some customers may already have the appropriate meters and will not need new meters.