Section:	Appendix 3.1	Page No.:	Page 28 Page 42 (Schedule C13) Page 59 (Schedule D5)
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Revenue		
Issue:	Consumer Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the Proof of Revenue calculations for each rate class/sub-class used to establish (per page 28) the Unadjusted Revenue for each rate class/sub-class as set out in Schedule C13.

b) Please confirm that the rates used in the Proof of Revenue calculations were those set out in PUB Order 48/13. If not, please explain the basis for the rates used.

c) Please confirm that the energy sales used in the Proof of Revenue calculations for each class/sub-class are the same as those set out in Schedule D5 – Total kW.h Sales After DSM (E20). If not, please explain why and provide the values used.

d) Please confirm that number of customers used in the Proof of Revenue calculations for each class/sub-class are the same as those set out in Schedule D5 – Forecast # of Cust (C90). If not, please explain why and provide the values used.

RATIONALE FOR QUESTION:

To understand the basis for the revenues used in the COSS.

RESPONSE:

Response to part a) and b):

The table below is a comparison of the 2013/14 Proof of Revenue to the Unadjusted Revenue set out in Schedule C13 of PCOSS14.

The Proof of Revenue for the 2013/14 year reflects April, 2013 revenues at rates effective September 1, 2012, approved in Order 117/12, and the remaining eleven months of revenues at rates effective May 1, 2013 which were approved in Order 43/13.

Rate Class / Sub-Class	PCOSS14 - Sched C13	Proof of Revenue	Difference
Residential	$562,089,257	$562,089,257	$0
Seasonal	$7,837,281	$7,837,281	$0
Water Heating	$1,171,461	$1,171,461	$0
Residential	**$571,097,999**	**$571,097,999**	**$0**
Non-Demand	$132,991,514	$132,434,092	$557,422
Seasonal	$558,674	$558,674	$0
Water Heating	$520,165	$520,165	$0
Small Non-Demand	**$134,070,352**	**$133,512,931**	**$557,421**
Small Demand	**$136,479,744**	**$136,479,401**	**$343**
SEP - GSM	$758,764	$758,764	$0
SEP = GSL	$62,096	$62,096	$0
SEP	**$820,860**	**$820,860**	**$0**
General Service - Medium	**$187,901,858**	**$187,901,500**	**$358**
0-30 kV	$85,477,535	$85,477,591	-$56
30-100 kV	$49,658,558	$49,620,020	$38,538
31-100 kV Curtailable	$8,926,647	$8,965,179	-$38,532
Over - 100 kV	$112,728,207	$112,664,150	$64,057
Over - 100 kV Curtailable	$79,075,263	$79,140,175	-$64,912
General Service - Large	**$335,866,210**	**$335,867,115**	**-$905**
Street Lighting	$18,594,032	$19,151,251	-$557,219
Sentinel Lighting	$3,056,945	$3,056,945	$0
Area & Roadway Lighting	**$21,650,978**	**$22,208,196**	**-$557,218**
Diesel - Residential	$635,837	$635,837	$0
Diesel - Full Cost	$6,064,970	$6,064,970	$0
Diesel	**$6,700,808**	**$6,700,807**	**$1**
Accrual - Other	$2,333,691	$2,333,691	$0
Miscellaneous - Non-Energy	$634,731	$634,731	$0
Late Pmt Charges & Cust Adj	$5,783,330	$5,783,330	$0
Total General Consumers	**$1,403,340,560**	**$1,403,340,561**	**-$1**

The Proof of Revenue shows an additional $557,219 in Street Lighting which is associated with lighting in bus shelters, phone booths, etc. In PCOSS14, this revenue is included in the GS Small Non-Demand subclass. Other differences in the schedule are due to the allocation of DSM adjustments.

Please see the following tables for the calculation of the one month of revenues at September 1, 2012 rates and eleven months of revenues at May 1, 2013 rates.

2013/14 Forecast - Residential

	2013/14 Forecast Customers and Energy		
	Customer Months	>200 Amp Cust Mths	kWh
Residential	5,546,604	46,687	7,344,419,997
DSM Savings	-	-	(41,215,066)
Seasonal	20,888		87,392,769
FRWH	46,584		19,793,747

	September 2012 Rates			2013/14 Revenue @ Sept 2012 Rates				
	Basic Chg Charge	>200 Amp Charge	Energy Charge	BC & >200	Energy	Total	Adj Factor	Adjusted Revenue
Residential	$6.85	$6.85	$0.06940	$38,314,043	$509,702,748	$548,016,791	0.9992	$547,567,731
DSM Savings	-	-	$0.06940	-	-	-	-	-$2,860,326
								$544,707,405
Seasonal	$82.20	-	$0.06940	$1,716,994	$6,065,058	$7,782,052	0.9911	$7,712,918
FRWH	$24.37	-	-					$1,135,217
Total Residential								**$553,555,540**

	May 1, 2013 Rates			2013/14 Revenue @ May 2013 Rates				
	Basic Chg Charge	>200 Amp Charge	Energy Charge	BC & >200	Energy	Total	Adj Factor	Adjusted Revenue
Residential	$7.09	$7.09	$0.07183	$39,656,433	$527,549,688	$567,206,122	0.9992	$566,741,337
DSM Savings	-	-	$0.07183					-$2,960,478
								$563,780,859
Seasonal	$85.08	-	$0.07183	$1,777,151	$6,277,423	$8,054,574	0.9911	$7,983,019
FRWH	$25.22	-	-					$1,174,840
Total Residential								**$572,938,718**

	Prorated 2013/14 Revenue		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
Residential	$48,533,171	$516,508,733	$565,041,904
DSM Savings	-$223,660	-$2,728,987	-$2,952,647
			$562,089,257
Seasonal	$4,161,669	$3,675,612	$7,837,281
Water Heating	$96,819	$1,074,642	$1,171,461
Total Residential			**$571,097,999**

2013/14 Forecast - General Service Small

	2013/14 Forecast Customers, Energy and Demand					
	Customer Months	Three Ph Cust Mths	1st 11000 kWh Block	Next 8500 kWh	Balance of kWh	Billing Demand
Non-Demand	622,680	137,576	1,483,793,902	123,573,652	-	-
DSM Savings - SND	-	-			(16,451,822)	
Seasonal	859		4,880,000		-	
Water Heating	4560				6,790,000	
Demand	149,167	98,551	844,315,065	468,671,021	758,423,411	2,450,921
LUBD SD	737	698			4,420,386	22,240
DSM Savings - SD	-	-			(27,102,023)	(88,700)

	September 2012 Rates						2013/14 Revenue @ Sept 2012 Rates					
	Basic Charge	Three Ph Charge	1st Block kWh Rate	2nd Block kWh Rate	Run-Off Rate	Demand Charge	BC & 3 Ph	Energy	Demand	Total	Adj. Factor	Revenue
Non-Demand	$18.55	$7.60	$0.0729	$0.0506	-	-	$12,596,292	$114,421,402	-	$127,017,694	1.0191	$129,440,169
DSM Savings	-	-	$0.06756		-	-	-	(1,111,485)	-	(1,111,485)	1.0000	-$1,111,485
Seasonal	$222.60	-	$0.0729		$0.0506		$191,213	$355,752	-	$546,965	1.0029	$548,539
FRWH	$110.53	-			-							$504,023
Total Non-Demand												**$129,381,246**
Demand	$18.55	$7.60	$0.0729	$0.0506	$0.0334	$8.55	$3,516,035	$110,596,664	$20,955,375	$135,068,074	0.9882	$133,469,402
LUBD SD	$18.55	$7.60		$0.0827		$2.14	$18,976	$365,566	$47,594	$432,136	0.9999	$432,114
DSM Savings	-	-		$0.03340		$8.55	-	(905,208)	(758,385)	(1,663,593)	1.0000	-$1,663,552
Total Demand												**$132,237,964**

	May 1, 2013 Rates						2013/14 Revenue @ May 2013 Rates					
	Basic Charge	Three Ph Charge	1st Block kWh Rate	2nd Block kWh Rate	Run-Off Rate	Demand Charge	BC & 3 Ph	Energy	Demand	Total	Factor	Revenue
Non-Demand	$19.20	$7.87	$0.07545	$0.05237	-	-	$13,038,179	$118,423,802	-	$131,461,981	1.0191	$133,969,217
DSM Savings	-	-		$0.06993								-$1,150,476
Seasonal	$230.40	-	$0.07545		$0.05237		$197,914	$368,196	-	$566,110	1.0029	$567,738
FRWH	$114.40	-			-							$521,671
Total Non-Demand												**$133,908,150**
Demand	$19.20	$7.87	$0.07545	$0.05237	0.03457	$8.85	$3,639,603	$114,466,570	$21,690,651	$139,796,824	0.9882	$138,142,182
LUBD SD	$19.20	$7.87		$0.08560		$2.21	$19,644	$378,385	$49,150	$447,179	0.9999	$447,156
DSM Savings	-	-		$0.03457		$8.85	-	(936,917)	(784,995)	(1,721,912)	1.0000	-$1,721,952
Total Demand												**$136,867,386**

	Prorated 2013/14 Revenue = Sched C13 PCOSS14		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
Small Non-Demand	$11,086,387	$122,494,923	$133,581,310
DSM Savings	-$92,856	-$1,054,362	-$1,147,218
Seasonal	$258,984	$299,690	$558,674
Water Heating	$42,997	$477,168	$520,165
			$133,512,931
Small Demand	$11,185,466	$126,565,112	$137,750,578
LUBD SD	$36,213	$409,683	$445,896
DSM Savings	-$138,977	-$1,578,096	-$1,717,073
			$136,479,401

2013/14 Forecast – SEP

	2013/14 Forecast Data	
	Cust Mths	kWh
SEP Medium	288	24,500,000
SEP Large	60	2,000,000

	September 2012 Rates			2013/14 Revenue @ Sept 2012 Rates				
	Basic Charge	Average Energy Charge	Distribution Charge	Basic Charge	Energy & Dist Charge	Total	Adj Factor	Adjusted Revenue
SEP Medium	$50.00	$0.02418	$0.0062	$14,400	$744,310	$758,710	1.000	$758,764
SEP Large	$100.00	$0.02475	$0.0033	$6,000	$56,100	$62,100	1.000	$62,096
Total SEP								**$820,860**

	May 2013 Rates			2013/14 Revenue @ May 2013 Rates				
	Basic Charge	Average Energy Charge	Distribution Charge	Basic Charge	Energy & Dist Charge	Total	Adj Factor	Adjusted Revenue
SEP Medium	$50.00	$0.02418	$0.0062	$14,400	$744,310	$758,710	1.000	$758,764
SEP Large	$100.00	$0.02475	$0.0033	$6,000	$56,100	$62,100	1.000	$62,096
Total SEP								**$820,860**

	Prorated 2013/14 Rev = Sched C13 PCOSS14		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
SEP Medium	$76,055	$682,709	$758,764
SEP Large	$5,923	$56,173	$62,096
Total SEP			**$820,860**

2013/14 Forecast - General Service Medium

	2013/14 Forecast Customers, Energy and Demand				
	Customer Months	1st 11000 kWh Block	Next 8500 kWh	Balance of kWh	Billing Demand
Medium	23,469	255,335,585	193,878,324	2,749,535,696	7,343,600
LUBD MD	219			4,344,815	39,877
DSM Savings	-			(27,108,485)	(86,077)

	September 2012 Rates					2013/14 Revenue @ Sept 2012 Rates					
	Basic Chg Charge	1st Block kWh Rate	2nd Block kWh Rate	Run-Off Rate	Demand Charge	BC	Energy	Demand	Total	Adj Factor	Adjusted Revenue
Medium	$27.60	$0.0729	$0.0506	0.0334	$8.55	$647,744	$120,258,700	$62,787,780	$183,694,224	0.9976	$183,246,900
LUBD MD	$27.60			$0.0827	$2.14	$6,044	$359,316	$85,337	$450,697	0.9865	$444,619
DSM Savings	-			$0.0334	$8.55	-	-$905,423	-$735,958	-$1,641,382	1.0000	-$1,641,383
Total Medium											**$182,050,136**

	May 2013 Rates					2013/14 Revenue @ May 2013 Rates					
	Basic Chg Charge	1st Block kWh Rate	2nd Block kWh Rate	Run-Off Rate	Demand Charge	BC	Energy	Demand	Total	Adj Factor	Adjusted Revenue
Medium	$28.57	$0.0755	$0.0524	0.03457	$8.85	$670,509	$124,469,927	$64,990,860	$190,131,296	0.9976	$189,668,296
LUBD MD	$28.57	$0.0856			$2.21	$6,257	$371,916	$88,128	$466,301	0.9865	$460,013
DSM Savings	-			$0.03457	$8.85	-	-$937,140	-$761,781	-$1,698,922	1.0001	-$1,699,025
Total Medium											**$188,429,284**

	Prorated 2013/14 Rev = Sched C13 PCOSS14		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
Medium	$15,162,386	$173,974,585	$189,136,971
LUBD MD	$36,789	$421,950	$458,739
DSM Savings	-$137,125	-$1,557,085	-$1,694,210
Total Medium			**$187,901,500**

2013/14 Forecast - General Service - Large

	2013/14 Forecast Customers, Energy, Demand		
	Cust Months	Energy	Demand
0 - 30 kV	3,420	1,715,323,934	4,064,015
0 - 30 kV LUBD	36	1,014,000	10,099
0 - 30 kV DSM	-	(13,016,271)	(33,681)
30 - 100 kV	468	1,108,570,000	2,567,348
30 - 100 kV DSM	-	(5,569,968)	(13,769)
30 - 100 kV Curt	12	225,000,000	340,796
Over 100 kV	144	2,849,450,000	5,059,236
Over 100 kV LUBD	24	1,029,000	28,981
Over 100 kV DSM	-	(4,287,512)	(9,560)
Over 100 kV Curt	24	2,070,000,000	3,375,442

	September 2012 Rates		2013/14 Revenue @ Sept 2012 Rates				
	Energy Charge	Demand Charge	Energy	Demand	Total	Adj Factor	Adjusted Revenue
0-30 kV	$0.0314	$7.26	$53,861,172	$29,504,749	$83,365,920	1.0002	$83,382,410
0-30 kV LUBD	$0.0732	$1.82	74,225	18,380	$92,605	1.0000	$92,604
0-30 kV DSM	$0.0314	$7.26	-$408,711	-$244,525	-$653,236	1.0000	-$653,236
							$82,821,778
30 - 100 kV	$0.0292	$6.21	32370244	15943231.08	$48,313,475	1.0002	$48,321,749
30 - 100 kV DSM	$0.0292	$6.21	-$162,643	-$85,504	-$248,147	1.0000	-$248,147
							$48,073,602
30 - 100 kV Curt	$0.0292	$6.21	$6,570,000	$2,116,343	$8,686,343	1.0000	$8,686,342
Over 100 kV	$0.0283	$5.53	$80,639,435	$27,977,575	$108,617,010	1.0045	$109,103,910
Over 100 kV LUBD	$0.0600	$1.41	$61,740	$40,863	$102,603	1.0000	$102,603
Over 100 kV DSM	$0.0283	$5.53	-$121,337	-$52,867	-$174,203	0.9891	-$172,302
							$109,034,211
Over 100 kV Curt	$0.0283	$5.53	$58,581,000	$18,666,194	$77,247,194	0.9922	$76,647,664
Total Large							**$325,263,597**

	May 2013 Rates		2013/14 Revenue @ May 2013 Rates				
	Energy Charge	Demand Charge	Energy	Demand	Total	Adj Factor	Adjusted Revenue
0-30 kV	$0.03250	$7.51	$55,748,028	$30,520,753	$86,268,781	1.0002	$86,285,845
0-30 kV LUBD	$0.0758	$1.88	$76,861	$18,986	$95,847	1.0000	$95,846
0-30 kV DSM	$0.03250	$7.51	-$423,029	-$252,945	-$675,974	1.0000	-$675,960
							$85,705,731
30 - 100 kV	$0.03022	$6.43	$33,500,985	$16,508,048	$50,009,033	1.0002	$50,017,597
30 - 100 kV DSM	$0.03022	$6.43	-$168,324	-$88,533	-$256,857	0.9998	-$256,810
							$49,760,787
30 - 100 kV Curt	$0.03022	$6.43	$6,799,500	$2,191,318	$8,990,818	1.0000	$8,990,817
Over 100 kV	$0.02929	$5.72	$83,460,391	$28,938,830	$112,399,220	1.0054	$113,004,331
Over 100 kV LUBD	$0.0621	$1.46	$63,901	$42,312	$106,213	1.0000	$106,213
Over 100 kV DSM	$0.02929	$5.72	-$125,581	-$54,683	-$180,264	0.9840	-$177,379
							$112,933,165
> 100 kV Curt	$0.02929	$5.72	$60,630,300	$19,307,528	$79,937,828	0.9924	$79,329,047
Total Large							**$336,719,547**

	Prorated 2013/14 Rev = Sched C13 PCOSS14		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
0-30 kV	$6,598,620	$79,457,457	$86,056,077
0-30 kV LUBD	$7,717	$87,859	$95,576
0-30 kV DSM	-$54,573	-$619,489	-$674,062
			$85,477,591
30 - 100 kV	$4,031,285	$45,844,821	$49,876,106
30 - 100 kV DSM	-20731	-$235,355	-$256,086
			$49,620,020
30 - 100 kV Curt	$731,446	$8,233,733	**$8,965,179**
Over 100 kV	$9,117,955	$103,617,238	$112,735,193
Over 100 kV LUBD	$8,550	$97,362	$105,912
Over 100 kV DSM	-$14,395	-$162,560	-$176,955
			$112,664,150
Over 100 kV Curt	$6,441,095	$72,699,080	**$79,140,175**
Total Large			**$335,867,115**

2013/14 Forecast - Area & Roadway Lighting

	2013/14 Forecast	
	Cust Months	kWh
Street Lighting	14,184	93,062,010
Sentinel FR	246,612	11,692,889
Sentinel Rental	311,688	-

	September 2012 Rates	2012/13 Revenue @ Sept 2012 Rates		
	Avg Wghted Price per Acct	Total Revenue	Adj Factor	Adj Revenue
Street Lighting	$1,308.32	$18,557,211	1.0000	$18,557,206
Sentinel FR	$3.14	$774,362	1.0006	$774,849
Sentinel Rental	$7.02	$2,188,050	0.9998	$2,187,511
Total A&RL				**$21,519,566**

	May 2013 Rates	2012/13 Revenue @ May 2013 Rates		
	Avg Wghted Price per Acct	Total Revenue	Adj Factor	Adj Revenue
Street Lighting	$1,354	$19,205,136	1.0000	$19,205,255
Sentinel FR	$3.25	$801,489	1.0008	$802,143
Sentinel Rental	$7.26	$2,262,855	1.0002	$2,263,401
Total A&RL				**$22,270,799**

Prorated 2013/14 Revenue = Sched C13 PCOSS14			
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
Street Lighting	$1,546,434	$17,604,817	$19,151,251
Sentinel FR	$64,571	$735,298	$799,869
Sentinel Rental	$182,293	$2,074,783	$2,257,076
Total A&RL			**$22,208,196**

2013/14 Forecast - Diesel

	2013/14 Forecast Customers and Energy		
	Cust Months	1st Bl kWh	Bal of kWh
Res Diesel	6,936	-	8,191,549
Fed Govt	564	-	1,776,600
Prov Govt	240	-	396,000
Non-Govt	1,320	1,238,970	2,151,218

	September 2012 Rates			2013/14 Revenue @ Sept 2012 Rates				
	Basic Chg Charge	1st Block Rate	Run-off Rate	BC	Energy	Total	Adj Factor	Adjusted Revenue
Diesel Res	$6.85		$0.0694	$47,512	$568,494	$616,005	1.0002	$616,124
Fed Govt	$18.55	-	$2.27	$10,462	$4,032,882	$4,043,344	0.9999	$4,043,080
Prov Govt	$18.55	-	$2.27	$4,452	$898,920	$903,372	0.9975	$901,149
Non-Govt	$18.55	$0.0729	$0.3730	$24,486	$892,725	$917,211	1.0174	$933,146
Diesel Full Cost								$5,877,375
Total Diesel								**$6,493,499**

	May 2013 Rates			2013/14 Revenue @ May 2013 Rates				
	Basic Chg Charge	1st Block Rate	Run-off Rate	BC	Energy	Total	Adj Factor	Adjusted Revenue
Diesel Res	$7.09		$0.07183	$49,176	$588,399	$637,575	1.0002	$637,698
Fed Govt	$19.20	-	$2.3495	$10,829	$4,174,122	$4,184,951	0.9999	$4,184,677
Prov Govt	$19.20	-	$2.3495	$4,608	$930,402	$935,010	0.9975	$932,709
Non-Govt	$19.20	$0.07545	$0.38605	$25,344	$923,958	$949,302	1.0174	$965,794
Diesel Full Cost								$6,083,180
Total Diesel								**$6,720,878**

	Prorated 2013/14 Revenue = Sched C13 PCOSS14		
	1 Month @ 2012 Rates	11 Months @ 2013 Rates	Total
Diesel Res	$53,145	$582,693	$635,838
Fed Govt	$357,732	$3,814,417	$4,172,148
Prov Govt	$79,734	$850,183	$929,917
Non-Govt	$82,565	$880,341	$962,905
Diesel Full Cost			$6,064,970
Total Diesel			**$6,700,808**

c) Not confirmed. Please see the following table for the explanation of differences between Schedule D5 in PCOSS14 and the 2013/14 Proof of Revenue.

a) Rate Class / Sub-Class	PCOSS14 – Sched D5	Proof of Revenue	Difference	Explanation
Residential	7,303	7,303	-	
Seasonal	87	87	-	
Water Heating	14	20	(6)	PCOSS applies 30% derate to account for a lower load factor and difference between nameplate rating and actual consumption of appliance
Residential	7,404	7,410	(6)	
Non-Demand	1,596	1,591	5	GSS Assumed Load included in GSS ND in PCOSS, included in A&RL in Proof of Revenue DSM savings in PCOSS include Internal Retrofit, excluded from Proof of Revenue
Demand	2,048	2,049	(1)	DSM savings in PCOSS include Internal Retrofit, excluded from Proof of Revenue
Seasonal	5	5	-	
Water Heating	5	7	(2)	PCOSS applies 30% derate to account for a lower load factor and difference between nameplate rating and actual consumption of appliance
General Service - Small	3,653	3,651	2	
General Service - Medium	3,175	3,176	(1)	
0-30 kV	1,702	1,703	(1)	DSM savings in PCOSS include Internal Retrofit, excluded from Proof of Revenue
30-100 kV	1,103	1,103	0	See above.
31-100 kV Curtailable	224	225	(1)	See above.
Over - 100 kV	2,841	2,846	(5)	See above.
Over - 100 kV Curtailable	2,063	2,070	(7)	See above.
General Service - Large	7,933	7,948	(14)	
SEP - GSM	25	25	-	
SEP - GSL	2	2	-	
SEP	27	27	-	
Street Lighting	89	93	(4)	PCOSS adjusts A&RL for increased hours of operation (4,252 vs 4,200)
Sentinel Lighting	12	12	(0)	GSS Assumed Load included in GSS ND in PCOSS, included in A&RL in Proof of Revenue
Area & Roadway Lighting	100	105	(4)	
Total General Consumers	**22,293**	**22,316**	**(24)**	

d) Confirmed, with the exception of the Small Non-Demand and Street Lighting. Schedule D5 reports the number of actual street lights whereas the Proof of Revenue reports the number of accounts, for which there is more than one street light per account. Note also that Schedule D5 reports average monthly customers whereas the Proof of Revenue reports "customer months" which is monthly customers times 12.

Rate Class / Sub-Class	PCOSS14 – Sched D5	Proof of Revenue	Difference	Variance Explanation
Residential	462,217	462,217	-	
Seasonal	20,888	20,888	-	
Water Heating	3,882	3,882	-	
Residential	486,987	486,987	-	
Non-Demand	52,539	51,890	649	GSS Assumed Load included in GSS ND in PCOSS, included in A&RL in Proof of Revenue
Demand	12,492	12,492	-	
Seasonal	859	859	-	
Water Heating	380	380	-	
General Service - Small	66,270	3,651	649	
General Service - Medium	1,974	1,974	-	
0-30 kV	288	288	-	
30-100 kV	39	39	-	
31-100 kV Curtailable	1	1	-	
Over - 100 kV	14	14	-	
Over - 100 kV Curtailable	2	2	-	
General Service - Large	344	344	-	
SEP - GSM	24	24	-	
SEP - GSL	5	5	-	
SEP	29	29	-	
Street Lighting	129,050	14,184	114,866	PCOSS uses street light fixtures, Proof of Revenue uses accounts GSS Assumed Load included in GSS ND in PCOSS, included in A&RL in Proof of Revenue
Sentinel Lighting (rentals)	25,974	25,974	-	
Area & Roadway Lighting	155,024	105	114,866	
Total General Consumers	**710,628**	**595,113**	**115,515**	

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	Page No.:	Page 44 (Schedule C14) Pages 42-43 (Schedule C13) Schedule 1 Page 37
Topic:	Financial Forecast Reconciliation		
Subtopic:	Revenue		
Issue:	Other Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the $14.6 M reported in Schedule C14 as "Other Revenue (non-energy)"; the $15 M in Other Revenue shown in IFF12 for 2013/2014; the $15 M shown in MIPUG MFR-2, Schedule 1 and $14.638 M shown in Schedule 13 all are equivalent. If not, please explain.

b) Please provide a breakdown as to the sources of this $14.638 M in Other Revenue (non-energy).

c) Please provide the rationale for assigning $123,000 of the $14,638,000 to Extra-Provincial Revenues.

d) Please provide the rational for assigning $14,515,000 of the $14,638,000 to Operating Expense.

e) Please provide a schedule that indicates how much of the $14,515,000 was assigned to each of the specific Operating Expense categories (per Schedule C12) and provide the rationale for each assignment.

RATIONALE FOR QUESTION:

To understand the adjustment that Manitoba Hydro has made to the revenues reported in IFF12 for purposes of the COSS and how this adjustment has impacted other aspects of the COSS.

RESPONSE:

a) Confirmed.

Response to parts b) to e):

Manitoba Hydro has elected to use Other Revenue to offset operating costs as part of the initial functionalization of costs in SAP, rather than performing an explicit allocation in the COSS. Miscellaneous revenues are not generally attributable to a specific customer class. For Cost of Service purposes, these revenues are used to reduce operating expense if revenues can be reasonably matched to a specific facility or by offsetting across all cost centers on the basis of labour charges.

The following is the breakdown and functionalization of the $14.6 million of Other Revenue in PCOSS14:

Other Revenue	2013/14 ($ thousands)	Function in PCOSS14
Operating Expense Recoveries	8,466	All functions in proportion to labour charges
Joint Use	4,504	Distribution – Poles & Wires
Island Falls Energy Transfer Agreement	785	Tariffable Transmission
Hot Water Tank	180	All functions in proportion to labour charges
Lake St Joseph Return	123	Adjustment to Export revenue
Other	579	All functions in proportion to labour charges

Section:	Appendix 3.1 MIPUG MFR 2	Page No.:	Page 44 (Schedule C14) Pages 42-43 (Schedule C13) Schedule 1
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Revenue		
Issue:	Miscellaneous – Non-Energy		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) What is the basis for the "Miscellaneous – Non-Energy" revenues of $634,731 per Schedule C13?

b) Where is this revenue reflected in: i) the IFF12 Revenue categories per Schedule C14 and ii) MIPUG MFR 2, Schedule 1?

c) Why is this revenue (after adjustment for BO 43/13) assigned to Extra-Provincial revenues?

RATIONALE FOR QUESTION:

To understand the adjustment that Manitoba Hydro has made to the revenues reported in IFF12 for purposes of the COSS and how this adjustment has impacted other aspects of the COSS.

RESPONSE:

a) The $634,731 shown for "Miscellaneous – Non-Energy" revenue pertains to revenues received from charges to retail customers situated outside of Manitoba that are served by way of connection to the Manitoba Hydro distribution system. Due to their location adjacent to the provincial boundary, it is more practical to serve them from the Manitoba Hydro system than from the utility in their service territory.

b) The revenue is reflected in “General Consumers Revenue” of $1,360.9 million in Schedule C14 of Appendix 3.1 and “Revenues (IFF12, pg 37)” of $1,768 million in Schedule 1 of MIPUG MFR 2.

c) Please see the response to part a).

Section:	Appendix 3.1 Revenue for PCOSS14 Model	**Page No.:**	Page 29 Page 44 (Schedule C14) Pages 42-43 (Schedule C13) Revenue Tab
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Revenue		
Issue:	Late Payment Charges & Cust Adj		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) How much of the $5,783,330 (prior to adjustment for BO 43/13) is associated with Late Payment Charges?

b) What are the other sources for the balance of the amount?

c) Appendix 3.1 (page 29) states that this amount is pro-rated to all customer classes except Street Lighting and GSL (>30 kV) based on the Unadjusted Revenue for each class. However, the Revenue or PCOSS14 Model shows that SEP <30KV is also excluded from the allocation. Please reconcile.

d) Please confirm that the allocation base used by Manitoba Hydro is the "Allowable Revenue per BO 43/13" column and not the "Unadjusted Revenue" in Schedule C13.

e) What have been the actual Late Payment Charge Revenues, by Revenue Class, for each of the past four years?

RATIONALE FOR QUESTION:

To understand the adjustment that Manitoba Hydro has made to the revenues reported in IFF12 for purposes of the COSS and how this adjustment as impacted other aspects of the COSS.

RESPONSE:

a) Late Payment Charges account for $4,131,600 of the $5,783,330.

b) The remaining $1,651,730 is associated with revenues obtained from miscellaneous charges such as inspection fees, disconnect/reconnect fees, federal meter disputes, and special read fees.

c) Confirmed. The GSL 0-30kV SEP customers have also been excluded from the allocation of Late Payment Charges and Customer Adjustments.

d) Confirmed.

e)

	Residential Late Payment Charges Billed			
	2015	**2014**	**2013**	**2012**
January	$254,003	$233,624	$258,379	$230,083
February	317,510	329,732	323,461	259,943
March	338,683	376,188	328,324	250,982
April	324,815	365,790	322,781	266,276
May	317,221	338,747	339,701	256,744
June	273,415	266,881	301,495	231,287
July	209,704	242,077	246,962	180,114
August	204,415	210,898	222,422	185,384
September	201,591	217,776	218,643	185,590
October	176,974	171,228	184,008	167,434
November	160,466	183,706	125,228	176,309
December	129,575	190,311	189,676	214,657
Total	$2,908,371	$3,126,957	$3,061,079	$2,604,804

	General Service Late Payment Charges Billed			
	2015	**2014**	**2013**	**2012**
January	$62,331	$63,551	$66,385	$67,884
February	68,718	80,613	43,243	62,871
March	68,746	82,969	108,674	71,535
April	63,171	52,016	59,176	77,336
May	75,815	45,080	59,964	52,181
June	47,781	69,245	61,558	54,451
July	49,269	58,213	63,420	52,334
August	49,229	55,815	54,347	55,914
September	45,787	64,166	60,107	53,880
October	43,067	52,582	16,616	46,680
November	43,453	48,248	33,930	52,886
December	40,595	56,259	65,733	61,351
Total	$657,963	$728,756	$693,152	$709,302

Section:	Appendix 3.1 MIPUG MFR 2 IFF12 15/16 & 16/17 GRA, Appendix 5.5	Page No.:	Page 27 Page 41 (Schedule C12) Schedule 1 Page 37 Page 21 (Schedule 5.5.16)
Topic:	Reconciliation of Financial Forecast		
Subtopic:	O&A Costs		
Issue:	Assignment to Cost Centres		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the $783.3 M in Operating costs are attributed to the cost centres set out in Schedule C12 (first column) by Manitoba Hydro's Financial Reporting System (SAP). If not, how are the Operating costs assigned to these cost centres?

b) Define each of the cost centres set out in the first column of Schedule C12 in terms of the activities and types of costs it includes.

c) A portion of Manitoba Hydro's Operating costs are associated with the business units such as Human Resources & Corporate Services (see last GRA, Appendix 5.5) that are not readily identified with any of the cost centres set out in Schedule C12 but rather support all activities of the Corporation. Does Manitoba Hydro's Financial Reporting System allocate these costs to various costs centres used in Schedule C12?
   i. If yes, are a portion of these costs allocated by SAP to Isolated Diesel Facilities?
   ii. If no, is this allocation done as part of the COSS and how is it done?

RATIONALE FOR QUESTION:

To understand how the level of detail to which the Operating Costs used in the COSS are tracked and recorded by Manitoba Hydro's financial systems.

RESPONSE:

a) Confirmed. Schedule C12 represents the fully costed facility cost centers flowing from SAP. Please see Manitoba Hydro's response to PUB/MH I-46a-b.

b) Manitoba Hydro has approximately 400 cost centers that are aggregated into the various categories on Schedules C12. Costs centers that relate to the Generation Facilities category include one cost center for each generating station, other generation-related facilities such as town sites, water management, mitigation, as well as common generation cost centers including research and development, power resource planning, external marketing, and purchased power. For an additional discussion of generation function components please see Manitoba Hydro's response to COALITION/MH I-26.

Costs centers that relate to the Transmission Facilities category include one cost center for each generation switching station, one cost center for each HVDC converter station and each northern collector system transmission line, one cost center per transmission and multifunction substation, approximately one cost center per transmission line as well as common transmission cost centers. For an additional discussion of transmission function components please see Manitoba Hydro's response to COALITION/MH I-27.

There is greater aggregation amongst the Subtransmission Facilities; there is a separate cost center for most subtransmission stations however, the majority of subtransmission lines are consolidated into a single cost center.

Costs related to Distribution Facilities are largely included in a small number of cost centers. There is single cost center for each of: Distribution Poles & Wires, Transformer and Voltage Regulation, Street Lighting, Sentinel Lighting, and Meters & Metering Transformers. Distribution substation costs are primarily consolidated into a single non-location specific cost center.

Customer Service cost centers include Billing, Collections, Meter Reading, Wiring Inspections and as well as a few general customer service cost centers as provided in Manitoba Hydro's response to MIPUG/MH I-4.

Isolated Diesel Facilities include site specific cost centers for generating facilities, distribution facilities and support activities.

The Communication & Control System category includes a cost center for system control and EMS/SCADA, as well as one for consolidated communication facilities.

c) Please see Manitoba Hydro’s response to PUB/MH I-46a-b.

Section:	Appendix 3.1	Page No.:	Pages 34-35 (Schedules C5 and C6) Page 26
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Depreciation		
Issue:	Capital Contributions		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether the depreciation charges set out in Schedule C6 are net of the annual amortization of capital contributions as set out in Schedule C5.

b) If not please provide a revised Schedule C6 where the depreciation shown is net of the annual amortization of capital contributions.

RATIONALE FOR QUESTION:

To clarify the basis for the Depreciation charges set out in the COSS schedules.

RESPONSE:

a) Confirmed.

b) Please see the response to part a).

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	Page No.:	Page 31 (Schedule C2) Pages 34-35 (Schedules C5 and C6) Page 26 Schedule 1 Page 37
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Depreciation		
Issue:	Assignment to Cost Centres		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the $420.97 M in Deprecation costs are attributed to the cost centres set out in Schedule C6 (first column) by Manitoba Hydro's Financial Reporting System (SAP). If not, how are the Depreciation costs assigned to these cost centres?

b) Please confirm that the Depreciation charges associated with Buildings and General Equipment asset classes (per Schedule C2) are assigned to the cost centres set out in Schedule C6 by Manitoba Hydro's Financial Reporting System (SAP).

c) If not, and if this assignment done as part of the COSS, please provide a schedule setting out how it was done for PCOSS14.

d) Please confirm if the Depreciation charges set out in Schedule C6 for Communications and Control Systems are related to the gross investment in the Communication asset class per Schedule C2. If not, what is the difference between the two, in terms of the related assets?

RATIONALE FOR QUESTION:

To clarify the basis for the Depreciation charges set out in the COSS schedules.

RESPONSE:

Response to parts a) to c):

Confirmed, Schedule C6 represents full-cost facility cost centers out of SAP. Please see Manitoba Hydro's response to PUB/MH I-46a-b.

d) Confirmed.

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	**Page No.:**	Pages 34-35 (Schedules C5 and C6) Page 26 Schedule 1 Page 37
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Depreciation		
Issue:	Diesel Contributions		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to MIPUG MFR 2, Schedule 1, please explain the basis for adding back the $1 M amortization of diesel contributions to Depreciation and deducting it from Interest. In doing so, please explain what the contributions were for and who made them.

RATIONALE FOR QUESTION:

To clarify the basis for the Depreciation charges set out in the COSS schedules.

RESPONSE:

The costs of diesel generation in the COS used to determine the diesel rate class' share of net export revenues. This includes the full capital cost of the facilities as provided in the Diesel Funding Agreement, and are not reduced by contributions received from external parties or notionally funded by Manitoba Hydro.

The $1 million amortization in PCOSS14 includes contributions from AANDC and other government agencies. The resulting decrease in Depreciation expense in the COS requires an offsetting increase in the amount of Contribution to Reserves (as part of Interest costs), to keep total revenues and total costs equivalent in the COS. Manitoba Hydro's notional contribution is not recorded in the financial statements and does not require this adjustment.

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	Page No.:	Page 40 (Schedule C11) Schedule 1 Page 37
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Interest and Reserve Contribution		
Issue:	Capital Tax		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that after Other Taxes are removed from the $96 M of Capital and Other Taxes reported in IFF12, what remains is just Capital Taxes.

RATIONALE FOR QUESTION:

To clarify the basis for the Interest charges set out in the COSS schedules.

RESPONSE:

Confirmed.

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	**Page No.:**	Page 38 (Schedule C9) Schedule 1 Page 37
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Interest and Reserve Contribution		
Issue:	Corporate Allocation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why the Corporate Allocation (net of $2 M included in Depreciation) is included in Interest.

RATIONALE FOR QUESTION:

To clarify the basis for the Interest charges set out in the COSS schedules.

RESPONSE:

The Interest portion of the Corporate Allocation represents the finance expense on the acquisition debt associated with the purchase of Centra Gas by Manitoba Hydro.

Section:	Appendix 3.1	**Page No.:**	Page 35 (Schedule C6) Page 38 (Schedule C9) Page 40 (Schedule C11) Page 41 (Schedule C12) Page 64 (Schedule E1)
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Interest & Reserve Contributions and Capital Tax		
Issue:			

PREAMBLE TO IR (IF ANY):

The cost functionalization-related schedules (i.e. Schedules C1-C12) set out the functionalization of four components of the revenue requirements: Net Depreciation (Schedule C6), Interest and Reserve Contribution (Schedule C9), Capital Tax (Schedule C11) and Operating Costs (Schedule C12). Schedule E1 sets out the allocation tables applied to each cost component of the revenue requirement by function and in the cases of Net Depreciation and Operating costs the totals in Schedule E1 match those in Schedules C6 and C12 respectively. However, the total reported for Interest in Schedule E1 does not reconcile with either the total for Interest and Reserve Contribution in Schedule C9 or the sum of the totals for Interest and Reserve Contributions (Schedule C9) and Capital Taxes (Schedule C11).

QUESTION:

a) Please confirm that the difference between the totals reported for Interest and Reserve Contribution ($462.8 M) and Capital Tax ($62.3 M) per Schedules C9 and C11 versus the total for Interest ($548.6 M) reported in Schedule E1 is the Uniform Rate Adjustment directly assigned to Exports. If not, please explain.

RATIONALE FOR QUESTION:

To clarify the basis for the Interest charges set out in the COSS schedules.

RESPONSE:

Confirmed.

Section:	Appendix 3.1 MIPUG MFR 2 IFF12	**Page No.:**	Page 44, Schedule C15 Schedule 2 Page 39
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Rate Base		
Issue:	COSS Adjustments		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain the following adjustments to Rate Base as set out in MIPUG MFR 2:

i. The exclusion of Goodwill,
ii. The exclusion of the Interest Obligation to the City of Winnipeg,
iii. The exclusion of Regulated Assets WIP (and in doing so explain what this is related to), and
iv. The exclusion of Diesel Non-refundable Contributions (and in doing so explain what this is related to).

RATIONALE FOR QUESTION:

To clarify the basis for the Rate Base set out in the COSS schedules.

RESPONSE:

Manitoba Hydro excludes Goodwill and the Interest Obligation to the City of Winnipeg from its calculation of Rate Base in COS as these assets are neither Plant in Service nor related to a specific function. As a result, they would be broadly functionalized and the inclusion or exclusion of these assets will not impact functionalization.

Assets are only included in Rate Base in COS once they are placed in-service and therefore while an asset is in Work in Progress it is excluded. Regulated Assets WIP in PCOSS14 includes computer development and site clean-up.

Please see Manitoba Hydro’s response to COALITION/MH I-8a for an explanation of the exclusion of the Diesel contribution from the PCOSS.

Section:	Appendix 3.1	**Page No.:**	Schedules C1, C2, C3, C4, C5, C7 and C10
Topic:	Functionalization		
Subtopic:	Fixed Assets		
Issue:	Assignment to Asset Classes		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Are Manitoba Hydro's financial records sufficiently detailed to provide the Asset Class break down (i.e., the first and second columns of each schedule) of Gross Assets, Accumulated Depreciation, Unamortized Capital Contributions, Capital Contribution Amortization, and Net Investment to the level of detail reported in the referenced schedules?

b) If not, please indicate those areas where some form of assignment or pro-ration was needed to split costs between asset classes and explain how this was done.

RATIONALE FOR QUESTION:

To understand the basis for the asset class assignment of costs underlying the COSS.

RESPONSE:

a) Yes.

b) Please see response the to part a).

Section:	Appendix 3.1	**Page No.:**	Page 37 (Schedule C8) Page 45 (Schedule C15) Page 35 (Schedule C6)
Topic:	Functionalization		
Subtopic:	Rate Base		
Issue:	Regulated Assets/Intangibles		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With reference to Schedule C15, please provide a schedule detailing the various items that make up the Total Net Regulated/Intangible Items and the average 2014 Rate Base investment associated with each?

b) For each of the items identified in response to part (a) with a value of over $10M, please indicate how it is assigned to the Asset Classes as set out in Schedule C8.

c) If the unamortized spending on DSM is not included in part (a) please explain why?

d) With respect to the response to part (b), please indicate where in Schedule C6 the annual amortization associated with each of these items is included. If not included in Schedule C6, please indicate where the annual amortization is captured in the COSS and assigned to functions.

RATIONALE FOR QUESTION:

To clarify the treatment of Regulated and Intangible Assets in the COSS schedules.

RESPONSE:

Response to parts a) and b):

Please refer to Table 1 and Schedule 1 below that provides the average 2014 Rate Base related to Net Regulated/Intangible Items that underpin Schedule C8 of PCOSS14-Amended).

Table 1

Item	**Average Rate Base**	**Functionalization in PCOSS14-Amended**
DSM	171,744,639	Generation row, functionalized as Generation
Generation Site Cleanup	21,340,754	Generation row, functionalized as Generation
Diesel Site (Site Cleanup, Easements)	4,418,293	Diesel row, functionalized as Diesel
Substation Easements	809,927	Substation row, functionalized based on Substation row opening balance Gross Investment
Transmission Easements	14,871,223	Transmission row, functionalized based on Transmission row opening balance Gross Investment
Distribution Site Clean- up & Easements	28,551,655	Distribution row, functionalized based on Distribution row opening balance Gross Investment
Subtransmission Easements	5,016,688	Subtransmission row, functionalized as Subtransmission
Communication (incl EAS. GIS)	3,169,719	Communications row, functionalized based on Communication row opening balance Gross Investment
Computer Development (inc SAP, MWM, EAM)	59,352,777	General Equipment row, functionalized based on operating costs excluding water rentals, fuel and power purchases
Building Easements & Site Clean up	65,515	Buildings row, functionalized based on operating costs excluding water rentals, fuel and power purchases
Electric Regulatory	2,499,464	General Equipment row, functionalized based on operating costs excluding water rentals, fuel and power purchases
Gas Integration Costs	8,190,711	General Equipment row, functionalized based on operating costs excluding water rentals, fuel and power purchases
Winnipeg Hydro Integration	3,672,569	General Equipment row, functionalized based on operating costs excluding water rentals, fuel and power purchases
Total Net Regulated Assets	**323,703,935**	

Schedule 1

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTANGIBLE/REGULATED ASSETS
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Net Assets Forecast Year 2	Generation	Transmission		Sub Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Tariffable	Non-Tariffable		Plant	Services		Lighting	Diesel
GENERATION	193,085,393	193,085,393	-	-	-	-	-	-	-	-
-Thermal	-	-	-	-	-	-	-	-	-	-
DIESEL	4,418,293	-	-	-	-	-	-	-	-	4,418,293
SUBSTATION	809,927	9,674	249,999	4,192	148,943	355,110	-	42,009	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
TRANSMISSION	14,871,223	-	10,636,717	4,234,506	-	-	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
DISTRIBUTION	28,551,655	-	-	-	-	26,608,266	-	-	1,943,389	-
SUBTRANSMISSION	5,016,688	-	-	-	5,016,688	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	-	-	-	-	-	-	-	-	-	-
BUILDINGS	65,515	28,142	8,273	1,754	3,029	10,953	12,324	-	1,041	-
COMMUNICATION	3,169,719	1,663,126	461,055	97,758	263,621	610,391	-	73,769	-	-
GENERAL EQUIPMENT	73,715,521	31,664,033	9,308,831	1,973,757	3,407,621	12,323,956	13,865,960	-	1,171,364	-
SUBTOTAL	323,703,935	226,450,368	20,664,875	6,311,967	8,839,901	39,908,676	13,878,283	115,777	3,115,795	4,418,293
MOTOR VEHICLES	-									
TOTAL NET COSTS	323,703,935	226,450,368	20,664,875	6,311,967	8,839,901	39,908,676	13,878,283	115,777	3,115,795	4,418,293

c) The unamortized spending on DSM is included in part a) above.

d) Please refer to Table 2 below that provides the requested description of where the annual amortization of the assets is included in Schedule C6 of PCOSS14-Amended.

Table 2

<table>
<tr><th>Item</th><th>Functionalization in Schedule C6 of PCOSS14-Amended</th></tr>
<tr><td>DSM</td><td>Common Generation Costs row, functionalized as Generation</td></tr>
<tr><td>Generation Site Cleanup</td><td>Common Generation Costs row, functionalized as Generation</td></tr>
<tr><td>Diesel Site (Site Cleanup, Easements)</td><td>Isolated Diesel Facilities row, functionalized as Generation</td></tr>
<tr><td>Substation Easements</td><td>Distribution Facilities & Costs row, functionalized as Distribution</td></tr>
<tr><td>Transmission Easements</td><td>Common Trans. Costs/Revenues row, functionalized as Transmission-Eligible and Transmission-Ineligible</td></tr>
<tr><td>Distribution Site Clean- up & Easements</td><td>Distribution Facilities & Costs row, functionalized as Distribution</td></tr>
<tr><td>Subtransmission Easements</td><td>Subtransmission Facilities & Costs row, functionalized as Subtransmission</td></tr>
<tr><td>Communication (incl EAS. GIS)</td><td>Communication & Control System Row, all functions</td></tr>
<tr><td>Computer Development (inc SAP, MWM, EAM)</td><td rowspan="5">All rows, all functions (included in the common and administrative depreciation allocated to individual cost centers)</td></tr>
<tr><td>Building Easements & Site Clean up</td></tr>
<tr><td>Electric Regulatory</td></tr>
<tr><td>Gas Integration Costs</td></tr>
<tr><td>Winnipeg Hydro Integration</td></tr>
<tr><td>Total Net Regulated Assets</td><td></td></tr>
</table>

Section:	Appendix 3 Appendix 3.1	Page No.:	Page 9 (Schedule E1-Amended) Page 65 (Schedule E1)
Topic:	Reconciliation of Financial Forecast		
Subtopic:	Revenue Requirement Components		
Issue:	Changes in Values		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why the total values for the sum of Energy, Demand and Customer for each of Interest, Depreciation and Operating Costs changed between PCOSS14 (Appendix 3.1 – Schedule E1) and PCOSS14-Amended (Appendix 3 – Schedule E1) when both are based on IFF12. For example, in the case of Interest the value is $548.6 M in PCOSS14 and $546.0 M in PCOSS14- Amended.

b) Please explain why in PCOSS14-Amended (Appendix 3 – Schedule E1) for each of the three cost components the total costs summed across the functions does not equal the total costs summed across the Energy, Demand and Customer.

RATIONALE FOR QUESTION:

To reconcile the total costs reported for PCOSS14 with those reported for PCOSS14-Amended.

RESPONSE:

Schedule E1 in PCOSS14-Amended included in Appendix 3 of the Submission did not include the costs of US Interconnections in the sub-totals shown for the Energy, Demand and Customer Components. The sub-totals were corrected in the PCOSS14-Amended Schedules that were provided on March 22, 2016.

Section:	Appendix 3	**Page No.:**	Pages 8-9 (Schedule E1- Amended) Page 4
Topic:	Direct Assignment		
Subtopic:	Generation - Exports		
Issue:	Nature of Directly Assigned Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the $23,532 k of Interest directly assigned to Exports is related to the Uniform Rate Adjustment. If not, please explain what it is related to.

b) Please confirm that the $12,800 k of Depreciation directly assigned to Exports is related to AEF Expenditures. If not, please explain what it is related to.

c) Please confirm that the $964 k of Operating costs directly assigned to Exports is related to the NEB costs (per page 4). If not, please explain what it is related to.

RATIONALE FOR QUESTION:

To clarify the costs directly assigned to Exports.

RESPONSE:

a) Confirmed.

b) Confirmed.

c) Confirmed.

Section:	Appendix 3	Page No.:	Pages 8-9 (Schedule E1- Amended) Page 4
Topic:	Direct Assignment		
Subtopic:	Generation - Exports		
Issue:	Nature of Directly Assigned Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Does the oversight by the NEB and reporting requirements of the NEB relate only to exports or does the NEB have any involvement in Manitoba Hydro's purchase power activities?

RATIONALE FOR QUESTION:

To clarify the costs directly assigned to Exports.

RESPONSE:

The oversight of the National Energy Board is set out in statutes and regulations. Discussions regarding any oversight of the NEB requires the provision of a legal opinion which Manitoba Hydro declines to provide.

With respect to reporting requirements, Manitoba Hydro reports to the NEB on energy physically imported by Manitoba Hydro from the US to Canada. In addition, Manitoba Hydro reports on energy physically exported from Canada to the US.

Manitoba Hydro does not report to the NEB total US energy sales or total US energy purchased nor on any imports/purchases or exports/sales within Canada.

Section:	Appendix 3	Page No.:	Pages 8-9 (Schedule E1- Amended) Page 4
Topic:	Direct Assignment		
Subtopic:	Generation - Exports		
Issue:	Nature of Directly Assigned Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

e) If the NEB has some involvement (either via oversight or reporting requirements) in Manitoba Hydro's purchase of power from extra-provincial sources, why isn't a portion of the NEB fees attributed to domestic customers?

RATIONALE FOR QUESTION:

To clarify the costs directly assigned to Exports.

RESPONSE:

Manitoba Hydro agrees that the NEB has some involvement in the purchase of power from extra-provincial sources. It may be reasonable to allocate these fees proportionately to all load consistent with its treatment of power purchases, trading desk and MISO fees as discussed in the COS Submission (page 17), however, given the minimal costs involved, either treatment would have negligible impacts to RCC.

Section:	Appendix 3.1 Appendix 3	Page No.:	Page 41 (Schedule C12) Page 65 (Schedule E1) Pages 8-9 (Schedule E1- Amended) Page 2
Topic:	Direct Assignment		
Subtopic:	Generation - Exports		
Issue:	PCOSS14-Amended Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Schedule E1 (from Appendix 3.1) reports an additional $512 k of Generation Depreciation costs directly assigned to Exports versus Appendix 3 (i.e. $13,312 vs. $12,800). Please explain what this additional amount is related to and which methodology changes outlined in Appendix 3 (pages 2-3) accounts for this change.

b) Schedule E1 (from Appendix 3.1) reports an additional $104,920 k of Generation Operating costs directly assigned to Exports versus Appendix 3 (i.e., $105,884 vs. $964). Please explain what this additional amount is related to and which methodology changes outlined in Appendix 3 (pages 2-3) account for this change.

c) Schedule E1 (from Appendix 3.1) reports an additional $1,696 k of Transmission Operating costs directly assigned to Exports versus Appendix 3 (i.e., $1,696 vs. $0). Please explain what this additional amount is related to and which methodology changes outlined in Appendix 3 (pages 2-3) account for this change.

d) Please reconcile the $107.58 M in Operating Costs directly assigned to Exports in Appendix 3.1 Schedule E1 ($105.884 + $1.696) with the $97.9 M of Operating costs directly assigned to Exports in Schedule C12 of the same Appendix and also in Schedule C12 for PCOSS14-Amended.

RATIONALE FOR QUESTION:

To understand the change in costs directly allocated to Exports in PCOSS14-Amended vs. PCOSS14.

RESPONSE:

a) PCOSS14 assigns 42% of "Trading Desk" costs to the export class, including $512 thousand of depreciation on common and administrative assets that has been assessed to the trading desk cost centers through SAP. In PCOSS14-Amended, trading desk costs, including this associated depreciation, are allocated as part of the pooled generation costs. This change is discussed in Appendix 3 (page 2):

> "Manitoba Hydro has aggregated its generation resources such that all domestic customer classes and Dependable export sales are allocated embedded cost proportionately on the basis that all resources support these loads."

b) PCOSS14 included direct assignment of Operating cost of $4.906 million related to 42% of "Trading Desk", $90.296 million of purchased power (excluding wind), and $9.718 million of water rentals and variable hydraulic O&M. In PCOSS14-Amended these costs are allocated as part of the pooled generation costs. This change is discussed in Appendix 3 (page 2):

> "Manitoba Hydro has aggregated its generation resources such that all domestic customer classes and Dependable export sales are allocated embedded cost proportionately on the basis that all resources support these loads.
>
> Power Purchases have been allocated to all sales proportionately on the basis that this resource supports all loads."

c) PCOSS14 directly assigns 42% of MISO fees to the export class, while in PCOSS14-Amended these costs are allocated as part of Transmission costs. This change is discussed on page 3 of the COS Methodology Review Submission:

> "Similarly, power purchases, trading desk and MISO fees support all load under some conditions and Manitoba Hydro intends to assign these costs proportionately to all load."

d) In Appendix 3, the $9.718 million of water rentals and variable hydraulic O&M directly assigned to exports are included in the Generation column, rather than as Export direct assignments of Schedule C12. The $107.58 million on Schedule E1 indicates the total amount of Operating costs directly assigned in PCOSS14.

As identified in Manitoba Hydro's letter of March 22, 2016, the incorrect version of Schedule C12 was included in Appendix 3 originally filed. In the updated filing the export Operating costs in both Schedules C12 and E1 are $964,000.

Section:	Appendix 3.1	**Page No.:**	Page 65 (Schedule E1) Page 11
Topic:	Direct Assignment		
Subtopic:	DSM		
Issue:	Apportionment to Customer Classes		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Pages 11-12 indicate that DSM costs are assigned to customer classes based on class participation over ten years. Please explain what is meant by "class participation". Does it mean the programming dollars spent on each class, the energy savings achieved by each class or some other measure of participation?

RATIONALE FOR QUESTION:

To understand the proposed basis for allocating DSM costs.

RESPONSE:

Class participation used to assign DSM program costs in the COSS refers to the expected energy savings achieved by each class.

Section:	Appendix 3.1	**Page No.:**	Page 65 (Schedule E1) Page 11
Topic:	Direct Assignment		
Subtopic:	DSM		
Issue:	Apportionment to Customer Classes		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a schedule that sets out how assignment factors used in PCOSS14 (and PCOSS14-Amended) were determined.

RATIONALE FOR QUESTION:

To understand the proposed basis for allocating DSM costs.

RESPONSE:

Each year the DSM forecast is revised to reflect updated market information. The revised forecast reflects the expected energy savings to be achieved by each DSM program along with the expected rate class participation for each program. These revised forecasts determine the updated assignment of DSM costs to rate classes in the COSS.

Please see the "Class Splits" tab of the spreadsheet DSM.xlsx filed March 11, 2016 for a breakdown of forecast energy savings and participating rate classes by DSM program.

Section:	Appendix 3.1	Page No.:	Page 65 (Schedule E1) Page 11
Topic:	Direct Assignment		
Subtopic:	DSM		
Issue:	Apportionment to Customer Classes		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) What is the principle intent/purpose of DSM programming and the associated spending? In particular, is the objective to benefit the participating customers or to provide overall system wide benefits?

RATIONALE FOR QUESTION:

To understand the proposed basis for allocating DSM costs.

RESPONSE:

Manitoba Hydro has multiple objectives in offering DSM programming with the primary objectives being meeting the energy needs of the province in the most economic and sustainable manner and assisting customers with managing their energy bills.

Section:	Appendix 3.1 2014/15 & 2015/16 GRA COALITION/MH I-67 a)	**Page No.:**	Page 65 (Schedule E1) Page 11
Topic:	Direct Assignment		
Subtopic:	DSM		
Issue:	Benefits of DSM		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Based on the values provided in COALITION/MH I-67 a), what are the marginal costs of supplying each of Manitoba Hydro's rate classes (i.e., Residential, GSS- ND, GSS-Demand, GSM, GSL 0-30 kV, GSL 30-100 kV and GSL>100 kV)? In responding, please provide for each rate class a breakdown of the marginal costs as between generation, transmission and distribution.

RATIONALE FOR QUESTION:

To understand the marginal cost savings by COSS function associated with load reductions.

RESPONSE:

The levelized marginal value used for the analysis in the 2015 DSM Plan is 7.67 cents per kW.h (at meter). A breakdown of the value is as follows:

Generation	6.23 ¢/kW.h
Transmission	0.66 ¢/kW.h
Distribution	0.78 ¢/kW.h

The levelized marginal value used for the analysis in the 2012 DSM forecast that was included in the PCOSS14 is 7.74 cents per kW.h (at meter). A breakdown of the value is as follows:

Generation	6.32 ¢/kW.h
Transmission	0.65 ¢/kW.h
Distribution	0.77 ¢/kW.h

Manitoba Hydro does not break marginal values into rate classes.

Section:	Appendix 3.1	**Page No.:**	Page 64 (Schedule E1)
Topic:	Direct Assignment		
Subtopic:	SEP		
Issue:	Basis for Costs Assigned		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain what the Generation Interest, Depreciation and Operating costs directly assigned to SEP-GSM and SEP-GSL 0-30 kV are related to and how they were determined.

b) Please explain what the Transmission Interest, Depreciation and Operating costs directly assigned to SEP-GSM and SEP-GSL 0-30 kV are related to and how they were determined.

RATIONALE FOR QUESTION:

To understand the direct assignment of cost to SEP customers.

RESPONSE:

Response to parts a) and b):

SEP customers are not allocated any Generation or Transmission costs in the PCOSS, instead the G&T costs are assumed to be equal to the amount of energy-related revenue received under market-based SEP rates. The distribution of these costs has been pro-rated between Generation/Transmission and Interest/Depreciation/Operating in Schedule E1 in proportion to overall costs for these functions.

Section:	Appendix 1 IFF12	Page No.:	Page 3 Page 4
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Basis for Dependable/Export Split		

PREAMBLE TO IR (IF ANY):

The text on page 3 states that:

"For COS purposes, Manitoba Hydro will continue to reflect a five-year forecasted average split between Dependable and Opportunity sales based on energy available under dependable water flows compared to average water flows for years 3-8 of the IFF. The result is that approximately 50% of Export sales are considered Dependable, 50% are considered Opportunity sales."

QUESTION:

a) Please confirm that for PCOSS14 years 3-8 of the underlying IFF are 2014/15 through 2019/20.

b) Please explain why the average does not include the year the COSS is based on.

c) Based on the Power Resource Plan underpinning IFF12 please provide the forecast dependable energy which is surplus to domestic sales and the forecast of energy that is surplus to domestic sales under average water flow conditions for each of the first eight years of IFF12.

RATIONALE FOR QUESTION:

To understand the basis for derivation of the split between Dependable and Opportunity Export sales.

RESPONSE:

a) Confirmed.

b) The five-year forecasted average excludes the 2013/14 test year as the energy supply in the year is based on median flow conditions starting with specific set of initial reservoir levels. The energy available for years three and on are based on the average under all flow conditions and therefore are better representation of long-term expectations as the annual supply are not affected by the particular starting conditions that affect year two.

c) The table below summarize energy surplus to domestic sales under dependable and average water flow conditions. In the dependable case, energy surplus to domestic sales includes signed and term firm contracts, diversity and capacity support contracts, and uncommitted firm exports. In the average water flow case, energy surplus to domestic sales additionally includes opportunity exports. Energy is reported at generation.

Energy Surplus to Domestic Sales (@ Generation)		
Year	**Dependable Conditions**	**Average Conditions**
2014	3637	7883
2015	3774	7586
2016	3609	7366
2017	3423	7347
2018	2973	6903
2019	3432	6785

Section:	Appendix 1 IFF12	**Page No.:**	Page 3 Page 4
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Basis for Dependable/Export Split		

PREAMBLE TO IR (IF ANY):

The text on page 3 states that:

"For COS purposes, Manitoba Hydro will continue to reflect a five-year forecasted average split between Dependable and Opportunity sales based on energy available under dependable water flows compared to average water flows for years 3-8 of the IFF. The result is that approximately 50% of Export sales are considered Dependable, 50% are considered Opportunity sales."

QUESTION:

d) Using the data from part (c), please provide the derivation of the Dependable/Opportunity sales split for PCOSS14.

e) Please confirm that the derivation of the split is not dependent on the nature of the actual export contracts Manitoba Hydro has entered or plans on entering into but rather on the forecast of energy available surplus to domestic needs under dependable and average water flow conditions.

RATIONALE FOR QUESTION:

To understand the basis for derivation of the split between Dependable and Opportunity Export sales.

RESPONSE:

d) Based on the data provided in part c) of the response, the 5 year average based on PCOSS14-Amended yields a 47% Dependable and 53% Opportunity ratio:

Energy Surplus to Domestic Sales			
Fiscal Year	Dependable Conditions (GWh)	Average Conditions (GWh)	Dependable Share
2014/15	3,637	7,883	46%
2015/16	3,774	7,586	50%
2016/17	3,609	7,366	49%
2017/18	3,423	7,347	47%
2018/19	2,973	6,903	43%
5 Year Average			47%

e) Manitoba Hydro's intention is to derive the split on the forecast of energy available surplus to domestic needs under dependable and average water flow conditions, not on actual export contracts. The derivation based on forecast energy available avoids the complexities associated with the classification of specific export sales particularly given the increasing variations in sales agreements, is transparent, and consistent with longer term cost responsibility inherent in median flow conditions that underpin COS.

Section:	Submission IFF12 IFF15	**Page No.:**	Page 15 Page 4 Page 6
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Types of Long Term Contracts		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Page 4 of IFF12 sets out a list of the existing and proposed long-term firm export contracts in place and contemplated at the time. Please describe the types of long-term firm export contracts represented in the list (e.g. Diversity Agreements, System Participation, etc.), outline of the reliability associated with each (i.e., the conditions under which service would not be provided), indicate those for which Manitoba Hydro is expected to have dependable resources available to serve the contracts and, if dependable resources are required, must they be domestic resources.

b) With respect to the contracts listed on page 4, please indicate which of the listed contracts fall into each category described in part (a).

c) Are there any other types or categories of long-term export contracts (firm or non-firm) that Manitoba Hydro has entered into in the past, has entered into subsequent to IFF12 or is considering entering into? If there are, please describe the degree of reliability associated with each and whether Manitoba Hydro is expected to have dependable resources available to serve the contracts.

d) With respect to the list of long-term firm exports set out in IFF15 (page 6), please indicate which category or type of export contract each represents.

e) With respect to the response to parts (a) and (c), please indicate which types of contracts are considered to be a commitment of Manitoba Hydro`s dependable energy resources for purposes of the Power Resource Plan.

f) Please confirm if the types of export contracts noted in response to part (e) are the ones that Manitoba Hydro considers to be Dependable sales for purposes of distinguishing between Dependable and Opportunity Export sales (per Submission, page 15). If not, how are Dependable sales, as the term is used on page 15, defined and why there is a difference?

g) Please provide a listing of the different types of long term contracts ordered according to which would be curtailed first if there was insufficient capability to serve. Please also include in the list Domestic Firm Load and Curtailable Domestic Service (assuming curtailment is available under the terms of the contract).

h) Based on the export contracts existing and contemplated at the time IFF12 was prepared, how much of the dependable energy surplus to domestic sales forecast for each of the first eight years in IFF12 was committed to support export contracts.

RATIONALE FOR QUESTION:

To understand the distinction between Dependable and Opportunity exports.

RESPONSE:

Given Manitoba Hydro's stated goals laid out in Section 4 of the Cost of Service Submission, Manitoba Hydro is of the view that its treatment of export revenues and costs described in Section 7.1, where 50% of exports are deemed Dependable and 50% are deemed Opportunity (with 0% embedded cost assignment) is appropriate. Manitoba Hydro is of the view that further detailed examination of export contracts with the objective of justifying additional assignment of costs to exports will result in an unfair favouring of large customer classes. This position was indicated in the Submission (page 15 on line 29) that "methodologies that result in a greater assignment of G&T costs to the Export Class will also tend to favour large customers over smaller customers." This is especially true given that Manitoba Hydro's system is not designed for dependable or opportunity exports, but rather to provide for power that is adequate for the needs of the Province at least cost which includes recognizing the benefits from exporting power surplus to their needs. The information provided in this

Information request demonstrates that all exports whether dependable or opportunity are less firm than Manitoba load.

Based on that understanding, please see the following responses:

a) Manitoba Hydro's IFF12 was predicated on the long term export contracts listed on page 4 of IFF12 which would be supplied from available accredited capacity and dependable resources. That list included the 300 MW Term Sheet with WPS which was conditional on the construction of Conawapa which subsequently has been removed from MH's plans.

   Manitoba Hydro's domestic firm load is served from dependable energy and system capacity resources which include Seasonal Diversity imports. Manitoba Hydro's System Power and Seasonal Diversity (export) contracts are also served from dependable energy resources but the capacity supply is restricted to surplus Manitoba capacity resources.

   In contrast to firm loads, opportunity exports are not restricted to the availability of dependable energy resources. These shorter term exports are arranged when profitable opportunities arise on an ongoing basis using any available surplus capacity or energy supplies.

   With regard to the reliability of the supply of power associated with Manitoba Hydro's long term export contracts, Manitoba Hydro does not differentiate between its obligation to supply capacity, dependable energy and firm transmission service to export customers as compared to domestic customers except in the following areas;

   i. With regard to having any ongoing commitment, Manitoba Hydro makes no assumption and has no obligation to serve firm contracts after the term of the contract has expired. This is different compared to domestic customers for whom Manitoba Hydro has the ongoing obligation to serve.
   ii. With regard to supply reliability, Manitoba Hydro maintains a 12% capacity planning reserve margin for firm Manitoba load whereas Manitoba Hydro carries no capacity planning reserve margin for export contracts. In addition, unlike for domestic load, export contracts contain specific curtailment of energy delivery provisions that permit Manitoba Hydro to curtail, suspend or financially settle energy deliveries obligations without penalty. Although Manitoba Hydro does not

guarantee service delivery to any customer, these curtailment provisions result in a lower level of supply reliability to export customers compared to domestic customers.

Curtailment provisions can be activated under circumstances when continuing to export would result in interruption to Manitoba firm load. They cover events such as loss of generation supply, or insufficient HVDC capability. In addition certain contracts also permit Manitoba Hydro the option of reducing energy deliveries under adverse water conditions such as drought when Manitoba Hydro anticipates that it may have insufficient domestic energy resources to serve the export obligation.

With regard to the reliability of transmission service in Manitoba associated with the delivery of export power, Manitoba Hydro arranges for firm service on the AC network from Dorsey to the border under Manitoba Hydro's Open Access Transmission Tariff. This point to point service is as firm (i.e. as reliable) as the network transmission service Manitoba Hydro has in place for domestic load.

With regard to transmission service on Manitoba Hydro's existing HVDC system, Manitoba Hydro cannot provide firm service to either domestic or firm export loads. To address this, Manitoba Hydro has curtailment provisions in its export contracts that allow for curtailments in circumstances when continued delivery of exports during a HVDC outage event would otherwise require curtailment of domestic load.

As indicated on page 4 of IIF12 there are three types of long term power sold by Manitoba Hydro. These are:

System Power Sale – which is a sale of accredited generating capacity and energy (dependable and non-dependable energy). Each contract specifies the capacity and energy amounts and the curtailment provisions associated with the delivery of energy. The sale defines the transmission service obligations of each party.

System Participation Sale – which is the old name for System Power Sale.

Seasonal Diversity Contract – which is the seasonal swap of surplus accredited capacity resources and associated energy by two utilities with the summer season being May to October and winter being November to April. The capacity that MH has available from this contract in the winter is included the capacity resources available to serve Manitoba load and its planning reserve requirement during the winter peak. Similar to System Power the Seasonal Diversity Contract specifies the capacity and energy amounts and the curtailment provisions associated with the delivery of energy. The sale defines the transmission service obligations of each party.

b) The list of contracts set out on page 4 of IFF12 have the following unique capacity and energy provisions:

1. System Participation Sale

i. MP 50 MW System Participation Sale – Manitoba Hydro to provide 50 MW of capacity and energy during the 5x16 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

ii. NSP 500 MW System Participation Sale – Manitoba Hydro to provide 500 MW of capacity and energy during the 5x16 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

2. System Power Sale

i. MP 250 MW System Power Sale – Manitoba Hydro to provide 250 MW of capacity and energy during the 7x16 hours. Manitoba Hydro has the option to reduce its weekend energy obligation to 4 hours per day from 16 in adverse water conditions. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

ii. NSP 375/325 MW System Power Sale – Manitoba Hydro to provide 375 MW of capacity and energy in the 5x16 and 2x4 hours during the summer and 325 MW of capacity and 5x12 and 2x4 hours during the winter. Manitoba Hydro has the option to reduce its winter energy supply obligation to 7x4 in adverse water conditions. Additional non-dependable energy may be available in other hours at MH's discretion.

iii. NSP 125 MW System Power Sale – Manitoba Hydro to provide 125 MW of capacity and energy in the 5x16 and 2x4 hours during the summer and 5x12 and 2x4 hours during the winter. Manitoba Hydro has the option to reduce its winter energy supply obligation to 7x4 in adverse water conditions. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

iv. WPS 100 MW System Power Sale – Manitoba Hydro to provide 100 MW of capacity and energy in the 7x16 hours. Manitoba Hydro has the option to reduce its weekend energy obligation to 4 hours per day from 16 in adverse water conditions. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

v. WPS 300 MW System Power Sale Term Sheet Sale – Manitoba Hydro to provide 300 MW of capacity and energy in the 7x16 hours. Manitoba Hydro has the option to reduce its weekend energy obligation to 4 hours per day from 16 in adverse water conditions. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.

3. Seasonal Diversity

i. GRE 150 MW Seasonal Diversity Sale – Manitoba Hydro to provide 150 MW of capacity between May to October and associated summer energy with the option to limit energy to a 20% capacity factor. GRE to provide 150 MW of capacity from November to April and associated winter energy with the option to limit energy to a 20% capacity factor.

ii. NSP 350 MW Seasonal Diversity Sale – Manitoba Hydro to provide 350 MW of capacity between May to October and a minimum obligation to offer NSP energy in the 7x4 hours. NSP to provide 350 MW of capacity from November to April and energy in all hours in which Manitoba Hydro's bid clears the MISO day-ahead market.

iii. GRE 200 MW Seasonal Diversity Sale – Manitoba Hydro to provide 200 MW of capacity between May to October and a minimum obligation to offer GRE energy in the 7x4 hours. GRE to provide 200 MW of capacity from November to April and energy in all hours in which Manitoba Hydro's bid clears the MISO day-ahead market.

c) Historically Manitoba Hydro has sold Firm Power on a long term basis. This product was similar to the old System Participation Power with the exception that Manitoba Hydro agreed to maintain planning capacity reserves for the sale amount in the same manner as for domestic load. The last sale of Firm Power was to Ontario Hydro from 1998 to 2003 in the amount of 200 MW.

d) The list of contracts set out on page 6 of IFF15 have the following provisions:

1. System Participation Sale – see response b) 1. above

2. **System Power Sale –** see response b) 2. above plus
   i. MP 50 MW System Power Sale – Manitoba Hydro to provide 50 MW of capacity and energy during the 5x16 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.
   ii. SaskPower 25 MW System Power Sale – Manitoba Hydro to provide 25 MW of capacity and energy during the 7x16 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.
   iii. WPS 108 MW System Power Sale – Manitoba Hydro to provide 108 MW of capacity and energy during the 5x16 and 2x4 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion.
   iv. SaskPower 100 MW System Power Sale Term Sheet – Manitoba Hydro to provide 100 MW of capacity and energy during the 6x16 hours. Additional non-dependable energy may be available in other hours at Manitoba Hydro's discretion

3. **Seasonal Diversity Sale –** see response b) 3. ii and iii above plus
   i. NSP 75 MW Seasonal Diversity Sale – Manitoba Hydro to provide 75 MW of capacity between May to October and an obligation to offer energy in the 7x4 hours. NSP to provide 75 MW of capacity between November to April and energy in all hours in which Manitoba Hydro's bid clears the day-ahead market.

4. **Zonal Resource Credits (ZRC) Capacity Sales**

   The following sales were included in the list of long term firm sales on page 6 of IFF15. However this categorization is incorrect as they are Opportunity Sales of capacity that do not impact Manitoba Hydro's resource plan.
   American Electric Power 79 MW ZRC June 2016 to May 2018
   American Electric Power 50 MW ZRC June 2018 to May 2020
   NextEra 30 MW June 2015 to May 2018
   NextEra 100 MW

e) Manitoba Hydro is obligated to include in its resource plan capacity and energy resources necessary to serve System Participation Sales, System Power Sales, and Seasonal Diversity Sales.

With regard to the NSP 325/375 MW sale, it was negotiated as a package along with the 350 MW Seasonal Diversity Agreement such that the supply obligations under the 325/375 MW System Power Agreement can be met independent of the Manitoba supply and demand balance.

f) Confirmed.

g) The following table lists Manitoba Hydro's export curtailment priority stack. In the case of a Manitoba emergency these sales types will be curtailed first based on the priority rating (from lowest priority to highest priority) before firm domestic load is curtailed. Where more than one contract has the same priority rating, curtailment within the rating group will be pro-rata. In the rare circumstances of a simultaneous energy emergency in MISO and in Manitoba, Manitoba Hydro will respond to the emergency in accordance to the instructions of the MISO Reliability Coordinator which may involve curtailment of both firm exports and domestic load such that the security of the entire electric grid is maintained.

<u>EXPORT CURTAILMENT PRIORITY STACK</u>

SALE TYPE	PRIORITY RATING	AGREEMENT/PRODUCT TYPE
Energy Only	1	Emergency Energy (Saskatchewan/Ontario)
	2	Real-Time*
	3	Day-Ahead
	4	Surplus/Non-Firm Energy
	5	Return Energy (Lake St. Joseph)*
	6	Firm Energy/Firm LD Energy **
Manitoba Curtailable Load	7	Manitoba Curtailable Rate Program
Capacity and Energy	8	Module E Grandfathered (Diversity Exchange, System Power Sales), Zonal Resource Credits (ZRC)
	9	Separated Load, Border Accommodations, MH's End-Use Load
Operating Reserves	10	Regulation, Spinning and Supplemental

h) The following table from Appendix A of the 2012/13 Power Resource Plan indicates what percentage of the dependable surplus was used to support dependable export sales.

Annual Dependable Energy GW.h @ Generation								
Fiscal Year	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Total Power Resources	29 964	30 425	30 544	31 029	31 147	31 441	31 500	31 421
Demand Side Management	- 62	- 171	- 268	- 351	- 430	- 501	- 570	- 622
Bipole III Line Reduction						- 243	- 243	- 243
Net Total Power Resources	**29 902**	**30 254**	**30 276**	**30 678**	**30 717**	**30 697**	**30 687**	**30 556**
Brandon Unit 5	- 811	- 811	- 811	- 811	- 811	- 811	- 811	
Net Total Available Power Resources	**29 091**	**29 443**	**29 465**	**29 867**	**29 906**	**29 886**	**29 876**	**30 556**
2012 Base Load Forecast	24 961	25 734	26 071	26 393	26 677	27 128	27 616	27 919
Non-Committed Construction Power		10	25	50	50	80	100	70
Demand Side Management	- 62	- 171	- 268	- 351	- 430	- 501	- 570	- 622
Bipole III Line Reduction						- 243	- 243	- 243
Manitoba Net Load	**24 899**	**25 573**	**25 828**	**26 092**	**26 297**	**26 464**	**26 903**	**27 124**
Dependable Energy Available for Export	**4 192**	**3 870**	**3 637**	**3 775**	**3 609**	**3 422**	**2 973**	**3 432**
Contracted Exports	3 293	3 156	3 156	2 115	2 012	2 012	2 012	2 012
Proposed Exports				162	162	162	162	162
Dependable Export Energy	**3 293**	**3 156**	**3 156**	**2 277**	**2 174**	**2 174**	**2 174**	**2 174**
Dependable Export Energy / Dependable Energy Available for Export	**79%**	**82%**	**87%**	**60%**	**60%**	**64%**	**73%**	**63%**

Section:	Submission Appendix 1 Appendix 2	Page No.:	Page 15 Pages 3-4 Page 6
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Hybrid Sales		

PREAMBLE TO IR (IF ANY):

In Appendix 1 (page 3), Manitoba Hydro states that it "intends to support these (hybrid) sales under low flow conditions although the means of supplying these sales may not exclusively consist of Manitoba Hydro resources".

QUESTION:

a) Please clarify the nature of Manitoba Hydro's supply obligations under the "hybrid" export sales and, in doing so, specifically address the following:
   - For hybrid export sales must Manitoba Hydro still ensure there are dependable resources available to serve them but that such resources can take the form of firm energy purchases instead of domestic resources?
   - How does Manitoba Hydro's obligation to supply (i.e. the circumstances under which it is required to supply hybrid export sales) compare with the types of long-term firm export contracts described in response to the preceding question?
   - Are hybrid export sales considered to be a commitment of Manitoba Hydro`s dependable energy resources for purposes of the Power Resource Plan?

RATIONALE FOR QUESTION:

To understand the distinction between Dependable and Opportunity exports and how it relates to "hybrid" exports.

RESPONSE:

Hybrid sales are export sales that are backed by dependable energy resources and accredited capacity in the same manner as other long term firm sales and firm Manitoba demand.

Hybrid export sales contracts are unique in that they involve arrangements such as capacity exchanges, adverse water provisions, or other mechanisms that add to MH's portfolio of dependable energy and accredited capacity resources. Through such arrangements hybrid sales are possible when otherwise they would not be, as without the sale contract the associated dependable energy would not be available. This is in contrast to traditional firm export sales which are independent of the source of supply of dependable energy.

In normal circumstances Manitoba Hydro uses surplus capacity and hydraulic energy to meet the hybrid sale obligation. These surplus resources would otherwise be used to make opportunity sales. Under adverse but rare conditions Manitoba Hydro has the right to trigger the arrangements in the hybrid sales contracts which may include financially settling the obligation or making firm energy purchases.

In resource planning, Manitoba Hydro only includes the dependable energy resources available under hybrid export sales to the extent necessary to meet the hybrid export obligation. As a result the energy resources available under hybrid sales are not assumed to be available to serve other firm load obligations.

Section:	Submission Appendix 1 Appendix 2	Page No.:	Page 15 Page 3 Page 6
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Transmission Service Requirements		

PREAMBLE TO IR (IF ANY):

It is understood that Manitoba Hydro uses Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) when exporting from the province of Manitoba and Transmission Service from the MISO and other Transmission Providers applicable OATTs is utilized from the Manitoba border to the applicable delivery point (per 2005 COSS Review, CAC/MSOS/MH I-16 d).

QUESTION:

a) Please confirm if the understanding set out in the preamble is correct.

b) Does Manitoba Hydro contract for firm transmission service (i.e., long term point to point or short term firm point to point) for its dependable sales? If not, under what circumstances would it be acceptable to use non-firm point to point service for dependable export sales?

c) Are there circumstances under which Manitoba Hydro would need to contract for firm service for its Opportunity sales? If so, please outline what they are. (Note: It is understood that Manitoba Hydro may use firm transmission service for Opportunity sales if already contracted for and available).

RATIONALE FOR QUESTION:

To understand the difference in transmission service requirements for Dependable versus Opportunity Export sales.

RESPONSE:

a) Manitoba Hydro confirms that for long term sales it arranges for Transmission Service in Manitoba under Manitoba Hydro's OATT. In MISO, transmission service under the MISO Tariff is generally arranged for and held by Manitoba Hydro's export counterparty.

b) Long term export sales involve the delivery of both dependable energy and accredited capacity. Accredited capacity can only be delivered using firm transmission service. In Manitoba, Manitoba Hydro will arrange for long term point to point service under its OATT while the export counterparty will contract for firm transmission service (usually long term network) under the MISO and other Transmission Providers applicable OATTs. Capacity sales cannot be delivered on non-firm transmission as the capacity must be available at all times.

c) Manitoba Hydro can utilize firm or non-firm service for opportunity sales. If an opportunity sale involves the sale of capacity, firm transmission service must be used.

Section:	Submission	Page No.:	Page 15
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Impact on Investment		

PREAMBLE TO IR (IF ANY):

The Submission states: "Dependable sales may alter investment development sequence and timing".

QUESTION:

a) Please describe the various circumstances under which commitments to Dependable Sales could alter investment sequencing and timing. In doing so, please address separately investments in generation versus transmission.

b) Could the possibility/likelihood of Opportunity sales also alter investment development sequence and timing?

c) If the response to part (b) is yes, please describe the types of circumstances under which this could occur.

RATIONALE FOR QUESTION:

To understand the distinction between Dependable and Opportunity exports.

RESPONSE:

a) MH plans for development of new resources, generation and transmission, to serve MB load. Depending on the development, as well as load growth, there can be varying amounts of dependable generation surplus to MB requirements that can be sold to an export customer. In the event that a dependable sale would require advancement of resources, this advancement would be considered in the business case for proceeding with the sale.

b) Opportunity sales are not guaranteed and Manitoba Hydro does not build infrastructure specifically to serve these sales. To meet Manitoba load reliably, Manitoba Hydro develops resources not only to meet annual energy requirements under low inflow conditions, but also to meet the demand needs in every hour of the year. As a result, surplus short term energy may result when water conditions are favorable and the system is not at peak load. This energy can be used to offset the need for thermal generation and imports, sold extraprovincially as opportunity sales, or spilled.

c) Please see Manitoba Hydro's response to part b) of this response.

Section:	Submission	Page No.:	Page 15
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Impact on Investment		

PREAMBLE TO IR (IF ANY):

The Submission states: "Dependable sales may alter investment development sequence and timing".

QUESTION:

d) If the response to part (b) is yes, what is the distinguishing difference between Dependable and Opportunity sales with respect to their impact on investment development that supports making a distinction between the two in the COSS (or is there any)?

RATIONALE FOR QUESTION:

To understand the distinction between Dependable and Opportunity exports.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH I-25b.

Please also see Manitoba Hydro's response to PUB/MH I-2b.

Section:	Appendix 3.1 PCOSS14-Amended (filed with COSS Model)	**Page No.:**	Page23, 25 and 27 Page 41 (Schedule C12) Page 65 (Schedule E1) Schedule C12 Schedule E1
Topic:	Functionalization		
Subtopic:	Operating Costs		
Issue:	Generation Facilities and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For each of the components making up Generation Facilities and Costs (Schedule C12), please provide a description as to the nature of the costs included (i.e., underlying activities, assets, etc.).

b) Please indicate what the $4.91 M of Operating costs directly assigned to Exports in Schedule C12 are related to.

c) Please explain the component costs making up the $156,256 k in Purchased Power/Export costs and explain the basis of the split between Generation and Exports.

d) Please explain why in Schedule C12 the Generation Operating costs directly assigned to Exports is the same for both PCOSS14 and PCOSS14-Amended, whereas in Schedule E1 the level of directly assigned Generation Operating costs differs between the two references.

e) It is noted that, contrary to the observations on page 23 and 25 that Ancillary Services includes items previous bundled in the Generation function, there are no Operating costs associated with any of the components of Generation Facilities & Cost that are assigned to Ancillary Services. Please reconcile.

RATIONALE FOR QUESTION:

To understand the assignment of Generation Facilities and Costs - Operating costs to COSS functions.

RESPONSE:

a) Generation Facilities and Costs on Schedule C12 consist of:

Common Generation Costs

- R&D Generation
- External Marketing
- Power Resource Planning
- Environmental Plan & Protection
- System Operating
- Demand Side Management

Generation Facilities Costs

- Hydraulic Generating Stations
- Water Management Costs
- Mitigation Costs
- Town Site Costs
- Thermal Generating Stations

Power Purchases/Export Costs

- Purchased Power
- Purchased Power – Wind
- NEB Assessment

b) The $4.91 million represents the Export related portion of ‘Trading Desk’ costs under the PCOSS14 approach. Please see Manitoba Hydro’s response to PUB/MH I-14 for further discussion.

c) The $156.256 million on Schedule D2 of PCOSS14 includes $64.996 million of wind purchases in the Generation column, and the Export direct assignment of $90.296 of power purchases and $964,000 of NEB charges.

d) The incorrect version of Schedule C12 was included in the PCOSS14-Amended initially filed on March 11, 2016. The revised schedule provided March 22, 2016 shows the difference in direct assignment to exports used in PCOSS14 versus PCOSS14-Amended.

e) Please see Manitoba Hydro's response to COALITION/MH I-30a.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Pages 23, 25 & 27 Page 41 (Schedule C12) Page 35 (Schedule C6) Schedule C12
Topic:	Functionalization		
Subtopic:	Operating Costs		
Issue:	Transmission Facilities and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For each of the components making up Transmission Facilities/Costs (Schedule C12), please provide a description as to the nature of the costs included (i.e., underlying activities, assets, etc.).

b) For each of the components of Transmission Facilities/Costs (per PCOSS14- Amended, Schedule C12, 1st column), were the costs identified as between Generation, Transmission-Tariffable, Transmission-Non-Tariffable and Ancillary Services through Manitoba Hydro's Financial Reporting System (SAP)?

c) If not, please identify which components were not assigned by SAP and how, in each of these cases, the costs were assigned to the different functions.

d) With respect to PCOSS14-Amended, for each of the components of Transmission Facilities/Costs, please indicate the nature of the Operating costs (i.e., the associated assets and/or activities) that are assigned to Generation.

e) For each of the cost centres included in Transmission Facilities/Costs where the assignment of costs to Generation and Transmission-Tariffable changed as between PCOSS14 and PCOSS14-Amended, please indicate the reason for the change.

f) For each of the changes noted in response to part (e) were Operating costs tracked in sufficient detail in Manitoba Hydro's Financial Reporting system to specifically identify the costs whose functionalization was changed? If not, how were the costs identified?

g) Pages 23 and 25 indicate that the Ancillary Services function includes specific items that were previously bundled the Generation or Transmission function. Please describe the types of operating costs that are captured in Transmission Facilities & Costs and assigned to Ancillary Services.

h) A comparison of Schedules C6 and C12 indicates a number of Transmission Facilities and Costs components where a portion of the depreciation costs are attributed to Ancillary Services but no Operating costs are attributed (e.g., Generation Switching Stations). Please explain why this is the case?

i) Please indicate what the $1.70 M of Operating costs directly assigned to Exports in Schedule C12 are related to.

RATIONALE FOR QUESTION:

To understand the assignment of Transmission Facilities and Costs - Operating costs to COSS functions.

RESPONSE:

Response to parts a) to c):

The following list provides the components of the Transmission Facilities and Costs on Schedule C12, as well as indicates whether the costs were functionalized directly out of SAP or as part of COS preparation :

<u>Common Transmission Costs/Revenues</u>

- R&D HVDC – Transmission: function per SAP
- R&D Transmission: functionalized in COS on Trans Op Cost
- External Marketing: functionalized in COS on Trans Op Cost
- Transmission Planning: functionalized in COS on Trans Op Cost
- Transmission Development Funds: function per SAP

- Environmental Plan/Protection: functionalized in COS on Trans Op Cost
- System Operating: functionalized in COS on Trans Op Cost
- System Protection : functionalized in COS on Trans Op Cost
- Wheeling Revenues: function per SAP

<u>Transmission Common</u>

- Transmission Station Shop Maintenance: function per SAP
- Substation – Land for Future Sites: function per SAP
- Planned Costs for Transmission Substations: function per SAP
- Planned Costs for Transmission Lines: functionalized in COS on Trans Op Cost

<u>Transmission Line and Station</u>

- Generation Switching Stations: function per SAP
- HVDC & Collector Circuits: function per SAP
- Substations Transmission: initial function per SAP, with final functionalization of multifunction stations in COS
- 500 kV Lines: function per SAP
- 230 kV Lines: function per SAP
- 138 kV Lines: function per SAP
- 115 kV Lines: function per SAP

d) The following are the Transmission facilities costs that have been functionalized as Generation in PCOSS14-Amended:

<u>Common Transmission Costs/Revenues</u>

- R&D HVDC Transmission

<u>Transmission Line and Station</u>

- Generation Switching Stations:
  - Long Spruce
  - Kettle
  - Limestone
- HVDC & Collector Circuits:
  - Radison Conv. Stn.
  - Henday Conv. Stn.

- Dorsey Conv. Stn.
- Henday 230 kV Sw.Yd.
- Radisson 138 kV Sw.Yd
- Dorsey-Henday-Radisson DC Trans Line
- Limestone-Henday 230 kV AC T/L
- Kettle-Radisson 138 kV AC T/L
- Long Spruce-Radisson 230 kV AC T/L
- Long Spruce-Henday 230 kV AC T/L

e) The $20.5 million of Operating costs for Dorsey Convertor station included in the Transmission-Tariffable function column in Schedule C12 of PCOSS14, was refunctionalized into the Generation column in PCOSS14-Amended. There are no additional assets refunctionalized between Generation and Transmission-Tariffable in the amended methodology.

f) Yes, costs related to the Dorsey Convertor station are recorded at a Cost Center level that allows direct identification of the costs.

g) As discussed in Manitoba Hydro's response to COALITION/MH I-30a, the Ancillary Services function separately identified in the PCOSS is limited to Schedule 1 - Scheduling Control and Dispatch Service exclusively. Transmission-related costs that are included in Scheduling Control and Dispatch Service include the cost of capacitors and reactors for VAr support and communication provided for system control purposes including, communications, instrumentation monitoring and SCADA. These costs are segregated for presentation purposes only which are re-aggregated with Transmission for purposes of allocation and have no impact on RCC or other outputs of the study.

h) Operating costs attributable to Schedule 1 were not identified for PCOSS14-Amended, but will be segregated consistent with the treatment of Depreciation in future studies. However, as stated in part e) above, operating costs with respect to Schedule 1 Ancillary Services costs do not impact PCOSS but may slightly impact the determination of the OATT.

i) The $1.7 million direct assignment to Exports represents the export class' share of MISO Fees in PCOSS14. However, the treatment of MISO fees in PCOSS14-Amended as discussed in Manitoba Hydro's COS Submission (page 17) have been pooled and assigned on a pro-rata basis across all load.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Page 41 (Schedule C12) Schedule C12
Topic:	Functionalization		
Subtopic:	Operating Costs		
Issue:	Communications & Control Systems		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to the Communications & Control Systems component, were the Operating costs tracked in sufficient detail by Manitoba Hydro's Financial Reporting System that they could be directly assigned to individual functions? If not, please provide a schedule indicating how the costs were assigned to functions.

b) Please explain why the assignment of Communication & Control System Operating costs as between Generation and Transmission-Tariffable did not change from PCOSS14 to PCOSS14-Amended even though there was a material re-assignment of HVDC assets as between the two COSS studies.

RATIONALE FOR QUESTION:

To understand the assignment of Communications & Control Systems – Operating costs to COSS functions.

RESPONSE:

a) Please see Manitoba Hydro's responses to PUB/MH I-45 and PUB/MH I-47.

b) Please see Manitoba Hydro's responses to COALITION/MH I-35a and COALITION/MH I-27f.

Section:	COSS Model - PCOSS14-Amended PCOSS14-Amended Specific Cost Details	Page No.:	Allocated Costs Tab
Topic:	Functionalization		
Subtopic:	Operating Costs		
Issue:	Treatment of Specific Facilities' Costs		

PREAMBLE TO IR (IF ANY):

In the above two references Manitoba Hydro has provided the Operating costs associated with specific Thermal Generation facilities, Dorsey and Bipole I & II.

QUESTION:

a) Do the specific cost details provided for the Dorsey Converter Stn (e.g. Operating cost of $20,445 k) represent the costs of the entire station (including the Switchyards) or just the cost of the converter?

b) For each of the facilities concerned do the Operating costs represent just the costs associated with the facilities themselves or do they also include a share of Corporate O&A costs (e.g. President & CEO costs, General Counsel & Corporate Secretary, Human Resources & Corporate Services, etc.)?

c) For each of the facilities concerned do the Depreciation costs represent just the costs associated with the facilities themselves or do they also include a share of the depreciation associated with Buildings and other "common" assets?

RATIONALE FOR QUESTION:

To understand the basis for the costs provided for specific facilities.

RESPONSE:

a) The $20.445 million of Operating costs and the $26.098 million of Depreciation costs included in the specific cost details for Dorsey Converter Station represent the costs related to the HVDC facilities only and not the Dorsey 230 and 500 kV AC switchyards.

b) Operating costs includes an allocation of corporate administrative and general costs.

c) Depreciation costs include the depreciation for facility, as well as a share of depreciation associated with buildings and general equipment.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	Page No.:	Page 23, 25 and 27 Page 35 (Schedule C6) Page 13 (Schedule C6)
Topic:	Functionalization		
Subtopic:	Depreciation		
Issue:	Generation Facilities and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) It is noted that, while the observations on page 23 and 25 state that Ancillary Services includes items previously bundled in the Generation function, there are no Depreciation costs associated with any of the components of Generation Facilities & Cost that are assigned to Ancillary Services. Please reconcile.

RATIONALE FOR QUESTION:

To understand the functionalization of Generation Facilities and Costs – Depreciation.

RESPONSE:

The Ancillary Services discussions at pages 23 and 25 of the PCOSS14 are intended to be a general discussion of the types of services. As clarified on page 23 of PCOSS14:

> *"The costs shown for Ancillary Services in the PCOSS are those of the Scheduling, System Control and Dispatch Service only. Although the costs of this service are functionalized separately, they are included with Transmission for the purpose of allocation."*

The only ancillary service segregated in the COSS for presentation purposes is for Scheduling, System Control and Dispatch Service. The costs separately identified for this service are included in the Transmission function and allocated consistent with all transmission-related costs in the COSS.

Other Ancillary Services as discussed at pages 23 and 25 of the PCOSS14 associated with Manitoba Hydro's generation facilities are not segregated in COSS.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Pages 23, 25 and 26 Page 35 (Schedule C6) Page 37 (Schedule C8) Page 13 (Schedule C6) Page 25 (Schedule C8)
Topic:	Functionalization		
Subtopic:	Depreciation		
Issue:	Transmission Facilities and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For each of the components of Transmission Facilities/Costs, were the depreciation costs that were assigned as between Generation, Transmission- Tariffable, Transmission-Non-Tariffable, and Ancillary Services identified/tracked through Manitoba Hydro's Financial Reporting System (SAP)?

b) If not, please identify which components were not assigned by SAP and how, in each of these cases, the costs were attributed to the different functions.

c) Pages 23 and 25 indicate that the Ancillary Services function includes specific items that were previously bundled the Generation or Transmission function. Please describe the types of assets for which depreciation costs are captured in Transmission Facilities & Costs and assigned to Ancillary Services.

d) With respect to Schedule C8, what types of assets are assigned to Ancillary Services? Please reconcile this response with the response to part (c).

e) With respect to PCOSS14-Amended, for each of the components of Transmission

Facilities/Costs, please indicate the nature of the Depreciation costs (i.e., the associated assets and/or activities) that are assigned to Generation.

f) For each of the cost centres included in Transmission Facilities/Costs where the assignment of depreciation costs to Generation and Transmission-Tariffable changed as between PCOSS14 and PCOSS14-Amended, please indicate the reason for the change.

RATIONALE FOR QUESTION:

To understand the functionalization of Transmission Facilities and Costs – Depreciation.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH I-27.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	Page No.:	Page 35 (Schedule C6) Page 37 (Schedule C8) Schedule C6
Topic:	Functionalization		
Subtopic:	Depreciation Costs		
Issue:	Communications & Control Systems		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to the Communications & Control Systems component, were the Depreciation costs tracked in sufficient detail by Manitoba Hydro's Financial Reporting System that they could be directly assigned to individual functions? If not, please provide a schedule indicating how the costs were assigned to functions.

b) With respect to Schedule C8, what types of assets are assigned to Ancillary Services and are the Depreciation costs assigned to Ancillary Services in Schedule C6 consistent with the asset assignment in Schedule C8?

c) Please explain why the assignment of Communication & Control System depreciation costs as between Generation and Transmission-Tariffable did not change from PCOSS14 to PCOSS14-Amended even though there was a material re-assignment of HVDC assets as between the two COSS studies.

RATIONALE FOR QUESTION:

To understand the functionalization of Communication & Control System - Depreciation.

RESPONSE:

a) Depreciation costs associated with Communications and Control systems are not tracked by function in Manitoba Hydro's Financial Report System. The treatment of these costs in COS is provided in responses to PUB/MH I-45 and PUB/MHI-47.

b) The Depreciation costs assigned to Ancillary Services in Schedule C6 are consistent with the asset assignment in Schedule C8. Please see Manitoba Hydro's response to COALITION/MH I-27f for a description of types of assets assigned to Ancillary Services.

c) Please see Manitoba Hydro's response to COALITION/MH I-35a.

Section:	COSS Model - PCOSS14-Amended PCOSS14-Amended Specific Cost Details	Page No.:	Allocated Costs Tab
Topic:	Functionalization		
Subtopic:	Depreciation Costs		
Issue:	Treatment of Specific Facilities' Costs		

PREAMBLE TO IR (IF ANY):

In the above two references Manitoba Hydro has provided the Depreciation costs associated with specific Thermal Generation facilities, Dorsey and Bipole I & II.

QUESTION:

a) Do the specific cost details provided for the Dorsey Converter Stn (e.g. Depreciation cost of $26,098 k) represent the costs for the entire station (including the Switchyards) or just for the converter?

b) For each of the facilities concerned do the Depreciation costs represent just the costs associated with the facilities themselves or do they also include a share of the depreciation associated with Buildings and other "common" assets?

RATIONALE FOR QUESTION:

To understand the basis for the costs provided for specific facilities.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-29a.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Pages 30, 31, 32, 33, 34, 36, 37 and 39 Schedules C1, C2, C3, C4, C5, C7, C8 and C10
Topic:	Functionalization		
Subtopic:	Assets and Investments		
Issue:	Assignment to Functions - General		

PREAMBLE TO IR (IF ANY):

Schedules C1, C2, C3, C4, C5, C7, C8 and C10 all use the same format.

QUESTION:

a) For each of these schedules is the recording of costs by asset class all done through Manitoba Hydro's Financial Reporting System? If not, how are the costs addressed in each schedule assigned to asset classes?

b) Is the recording of assets by asset class sufficiently detailed to allow the assets related with each COSS function to be directly identified?

c) In those cases where it is not sufficiently detailed, please provide a schedule indicating how the costs (as set out in the 2nd column of each schedule) were assigned to functions.

d) Does the Meters asset class include only meters at customers' premises used for billing purposes? If so, doesn't Manitoba Hydro have other metering on its system and where are the associated assets costs included? If not, why are all Meter assets assigned to Distribution Plant?

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

a) Please see Manitoba Hydro's response to COALITION/MH I-13a.

b) Asset detail is available at the cost center level to allow functionalization of most asset classes including:

- Generation
- Generation – Thermal
- Diesel
- Substation – HVDC
- Distribution
- Subtransmission
- Transformers – Distribution
- Meters

c) The costs of substations that are entirely distribution related are available in aggregate at the cost center level to allow functionalization. Multi-function substations are functionalized between Transmission, Sub-transmission and Distribution based on the proportion of estimated replacement costs of the equipment at each station. The multi-function substation analysis in PCOSS14-Amended is included in the attachment to this response.

The inventory of in-stock Transformers - Substation is functionalized in proportion to Substation investment, excluding HVDC.

Please see Manitoba Hydro's responses to COALITION/MH I-35, PUB/MH I-45 and PUB/MH I-47 for a discussion of the functionalization of Buildings, General Equipment and Communication assets.

d) The Meters asset class only includes distribution meters and metering transformers used for billing purposes. Manitoba Hydro has additional transmission system metering installed at substations and generation stations. The cost of this metering is included and functionalized as part of the total cost of each substation.

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Ashern	12	Dct1	12 kV - Disconnects	12	5,000					60,000	1				12
		Trf1	12 kV - 66/12kV Power Transformer - 10 MVA	2	1,000,000					2,000,000	20				40
		Rclr1	12 kV - Reclosers	3	25,000					75,000	10				30
	66	Trf2	66 kV - 230/66 kV Power Transformer - 50 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		CT2	66 kV - CT	6	12,000				72,000		1			6	
		Dct2	66 kV - Disconnects	15	8,000				120,000		1			15	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	4	5,000				20,000		2			8	
	230	Brk4	230 kV - Breakers	7	200,000	1,400,000					27	189			
		CT4	230 kV - CT	7	50,000	350,000					3	21			
		CSW4	230 kV - Curicuit Switcher	1	150,000	150,000					15	15			
		Dct4	230 kV - Disconnects	14	12,000	168,000					1	14			
		GDct3	230 kV - Grnd Disconnects	5	18,000	90,000					1	5			
		MODct3	230 kV - MODisconnects	7	18,000	126,000					1	7			
		PT4	230 kV - PT	12	15,000	180,000					4	48			
		Rctr2	230 kV - Reactor 50 MVAR	1	2,500,000		2,500,000				20	20			
						2,464,000	2,500,000	-	6,812,000	2,135,000		319	-	221	82
						18%	18%	0%	49%	15%		51%	0%	36%	13%
Birtle - 2644	66	Trf2	66 kV - 230/66 kV Power Transformer - 50 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		Cap	66 kV - Capacitor - 5 MVAR	2	60,000				120,000		8			16	
		CSw2	66 kV - Circuit Switcher	2	70,000				140,000		15			30	
		CT2	66 kV - CT	7	12,000				84,000		1			7	
		Dct2	66 kV - Disconnects	18	8,000				144,000		1			18	
		GDct1	66 kV - Grnd Disconnects	2	12,000				24,000		1			2	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	5	5,000				25,000		2			10	
	230	Brk4	230 kV - Breakers	2	200,000	400,000					27	54			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		Dct4	230 kV - Disconnects	4	12,000	48,000					1	4			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
						816,000	-	-	7,037,000	-		92	-	252	-
						10%	0%	0%	90%	0%		27%	0%	73%	0%
Border	115	Brk3	115 kV - Breakers	4											
		CT3	115 kV - CT	4											
		Dct3	115 kV - Disconnects	8											
		GDct2	115 kV - Grnd Disconnects	4											
		MODct2	115 kV - MODisconnects	4											
		PT3	115 kV - PT	10											
						100%						100%			

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Brandon SW Stn	115	Brk3	115 kV - Breakers	29	128,000	3,712,000									
		CT3	115 kV - CT	29	35,000	1,015,000									
		CSw3	115 kV - Circuit Switcher	3	100,000	300,000									
		Dct3	115 kV - Disconnects	63	9,700	611,100									
		GDct2	115 kV - Grnd Disconnects	17	15,000	255,000									
		MODct2	115 kV - MODisconnects	24	15,000	360,000									
		PT3	115 kV - PT	11	9,000	99,000									
		Cap	115 kV - Capacitor 50 MVA	3	600,000		1,800,000								
						6,352,100	1,800,000	-	-	-					
						78%	22%	0%	0%	0%		100%			
Brandon-Victoria - 2060	12	Dct1	12 kV - Disconnects	3	5,000					15,000	1				3
		Trf1	12 kV - 33/12 KV Power Transformer 3 MVA	2	1,000,000					2,000,000	20				40
	33	Trf1	33 kV - 115/33kV Power Transformer - 15 MVA	1	1,000,000				1,000,000		20			20	
		Trf2	33 kV - 115/33kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Brk1	33 kV - Breakers	10	100,000				1,000,000		23			230	
		Dct1	33 kV - Disconnects	30	5,000				150,000		1			30	
		GBnk1	33 kV - Ground Bank	2	261,000				522,000		20			40	
		PT1	33 kV - PT	3	3,000				9,000		1			3	
	66	Trf2	66 kV - 230/66 kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	8	100,000				800,000		23			184	
		CT2	66 kV - CT	8	12,000				96,000		1			8	
		Dct2	66 kV - Disconnects	30	8,000				240,000		1			30	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		MODct1	66 kV - MODisconnects	2	12,000				24,000		1			2	
		PT2	66 kV - PT	1	5,000				5,000		2			2	
	115	Brk3	115 kV - Breakers	10	128,000	1,280,000					20	200			
		CT3	115 kV - CT	4	35,000	140,000					1	4			
		Dct3	115 kV - Disconnects	20	9,700	194,000					1	20			
		GDct2	115 kV - Grnd Disconnects	5	15,000	75,000					1	5			
		MODct2	115 kV - MODisconnects	8	15,000	120,000					1	8			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						1,827,000			14,846,000	2,015,000		241		643	43
						10%			79%	11%		26%		69%	5%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Cliff Lake - 2744	115	GDct2	115 kV - Grnd Disconnects	2	15,000	30,000									
		MODct2	115 kV - MODisconnects	3	15,000	45,000									
		PT3	115 kV - PT	2	9,000	18,000									
		Trf1	115 kV - 230/115 kV Power Transformer - 225 MVA	2	1,000,000	2,000,000									
		Trf1	115 kV - 230/115 kV Power Transformer - 125 MVA	1	1,000,000	1,000,000									
	230	Brk4	230 kV - Breakers	4	200,000	800,000									
		CSw4	230 kV - Circuit Switcher	1	150,000	150,000									
		CT4	230 kV - CT	4	50,000	200,000									
		Dct4	230 kV - Disconnects	10	12,000	120,000									
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000									
		MODct3	230 kV - MODisconnects	5	18,000	90,000									
		PT4	230 kV - PT	6	15,000	90,000									
		Rctr2	230 kV - Reactor 50 MVAR	1	2,500,000		2,500,000								
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	3	100,000	300,000									
		Cap	13.8 Voltage Control - Capacitor - 12 MVAR	3	144,000		432,000								
		Dct1	13.8 Voltage Control - Disconnects	7	5,000	35,000									
		PT1	13.8 Voltage Control - PT	4	3,000	12,000									
						4,926,000	2,932,000	-	-	-					
						63%	37%	0.0%	0.0%	0.0%		100%			
Cornwallis - 2590	115	Trf1	115 kV - 230/115 kV Power Transformer - 176 MVA	2	1,000,000	2,000,000									
		Trf1	115 kV - 230/115 kV Power Transformer - 250 MVA	1	1,000,000	1,000,000									
	230	Brk4	230 kV - Breakers	7	200,000	1,400,000									
		CSw4	230 kV - Circuit Switcher	1	150,000	150,000									
		CT4	230 kV - CT	7	50,000	350,000									
		Dct4	230 kV - Disconnects	15	12,000	180,000									
		GDct3	230 kV - Grnd Disconnects	4	18,000	72,000									
		MODct3	230 kV - MODisconnects	7	18,000	126,000									
		PT4	230 kV - PT	11	15,000	165,000									
		Rctr2	230 kV - Reactor 20 MVAR	1	2,500,000		2,500,000								
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	6	100,000	600,000									
		Dct1	13.8 Voltage Control - Disconnects	6	5,000	30,000									
		PT1	13.8 Voltage Control - PT	3	3,000	9,000									
		Rctr2	13.8 Voltage Control - Reactor - 20 MVAR	3	2,500,000		7,500,000								
		Rctr1	13.8 Voltage Control - Reactro - 15 MVAR	1	1,000,000		1,000,000								
						6,082,000	11,000,000	-	-	-					
						36%	64%	0%	0%	0%		100%			

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Dauphin - Vermillion -2594	12	Trf1	12 kV - 66/12kV Power Transformer - 11.25 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV - Disconnects	15	5,000					75,000	1				15
		Rclr1	12 kV - Reclosers	5	25,000					125,000	10				50
	66	Trf2	66 kV - 230/66 kV Power Transformer - 66.6 MVA	1	2,500,000				2,500,000		20			20	
		Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	1	4,000,000				4,000,000		55			55	
		Brk2	66 kV - Breakers	9	100,000				900,000		23			207	
		CT2	66 kV - CT	2	12,000				24,000		1			2	
		Dct2	66 kV - Disconnects	39	8,000				312,000		1			39	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	8	200,000	1,600,000					27	216			
		CT4	230 kV - CT	9	50,000	450,000					3	27			
		CSW4	230 kV - Curicuit Switcher	2	150,000	300,000					15	30			
		Dct4	230 kV - Disconnects	14	12,000	168,000					1	14			
		GDct3	230 kV - Grnd Disconnects	5	18,000	90,000					1	5			
		MODct3	230 kV - MODisconnects	9	18,000	162,000					1	9			
		PT4	230 kV - PT	2	15,000	30,000					4	8			
		Rctr2	230 kV - Reactor 30 MVAR	1	2,500,000		2,500,000				20	20			
		Rctr2	230 kV - Reactor 50 MVAR	1	2,500,000		2,500,000				20	20			
						2,800,000	5,000,000	-	8,746,000	1,200,000		349		341	85
						16%	28%	0%	49%	7%		45%		44%	11%
Glenboro	66	Trf2	66 kV - 230/66 kV Power Transformer - 50 MVA	3	2,500,000				7,500,000		20			60	
		Brk2	66 kV - Breakers	8	100,000				800,000		23			184	
		Cap	66 kV - Capacitor - 20 MVAR	2	240,000				480,000		8			16	
		CSw2	66 kV - Circuit Switcher	2	70,000				140,000		15			30	
		CT2	66 kV - CT	10	12,000				120,000		1			10	
		Dct2	66 kV - Disconnects	28	8,000				224,000		1			28	
		GDct1	66 kV - Grnd Disconnects	2	12,000				24,000		1			2	
		GBnk2	66 kV - Ground Bank	3	500,000				1,500,000		7			21	
		PT2	66 kV - PT	4	5,000				20,000		2			8	
	230	Brk4	230 kV - Breakers	6	200,000	1,200,000					27	162			
		CSw4	230 kV - Circuit Switcher	1	150,000	150,000					15	15			
		CT4	230 kV - CT	6	50,000	300,000					3	18			
		Dct4	230 kV - Disconnects	13	12,000	156,000					1	13			
		GDct3	230 kV - Grnd Disconnects	3	18,000	54,000					1	3			
		MODct3	230 kV - MODisconnects	6	18,000	108,000					1	6			
		PT4	230 kV - PT	9	15,000	135,000					4	36			
		Rctr2	230 kV - Reactor 30 MVAR	1	2,500,000		2,500,000				20	20			
						2,103,000	2,500,000	-	10,808,000	-		273		359	-
						14%	16%	0%	70%	0%		43%		57%	0%

Sum of Number of Components Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Extended Cost Tran Cost	Extended Cost Ancillary Cost	Extended Cost Non Eligible Tran Cost	Extended Cost ST Cost	Extended Cost Dist Cost	Maintenance Hours	Extended Hours Tran Cost	Extended Hours Non Eligible Tran Cost	Extended Hours ST Cost	Extended Hours Ddst Cost
Harrow	24	Trf2	24 kV - 115/24kV Power Transformer - 60 MVA	1	2,500,000					2,500,000	20				20
		Brk1	24 kV - Breakers	2	100,000					200,000	23				46
		Dct1	24 kV - Disconnects	11	5,000					55,000	1				11
		PT1	24 kV - PT	2	3,000					6,000	1				2
	66	Trf2	66 kV - 115/66 kV Power Transformer - 30 MVA	3	2,500,000				7,500,000		20			60	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		Dct2	66 kV - Disconnects	21	8,000				168,000		1			21	
		GDct1	66 kV - Grnd Disconnects	2	12,000				24,000		1			2	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	1	5,000				5,000		2			2	
	115	Brk3	115 kV - Breakers	8	128,000	1,024,000					20	160			
		CT3	115 kV - CT	8	35,000	280,000					1	8			
		Dct3	115 kV - Disconnects	16	9,700	155,200					1	16			
		GDct2	115 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		MODct2	115 kV - MODisconnects	7	15,000	105,000					1	7			
		PT3	115 kV - PT	5	9,000	45,000					2	10			
						1,669,200			9,197,000	2,761,000		205		214	79
						12%			68%	20%		41%		43%	16%
Herblet Lake	115	Trf2	115 kV - 230/115 kV Power Transformer - 50 MVA	2											
		Brk3	115 kV - Breakers	3											
		CT3	115 kV - CT	3											
		Dct3	115 kV - Disconnects	8											
		GDct2	115 kV - Grnd Disconnects	2											
		MODct2	115 kV - MODisconnects	2											
		PT3	115 kV - PT	2											
	230	Brk4	230 kV - Breakers	4											
		CT4	230 kV - CT	4											
		Dct4	230 kV - Disconnects	9											
		GDct3	230 kV - Grnd Disconnects	2											
		MODct3	230 kV - MODisconnects	4											
		PT4	230 kV - PT	6											
						100%						100%			
Inco	138	Brk3	138 kV - Breakers	8											
		CT3	138 kV - CT	8											
		Dct3	138 kV - Disconnects	22											
		GDct2	138 kV - Grnd Disconnects	4											
		PT3	138 kV - PT	6											
						100%						100%			

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Kirkfield Park	24	Trf2	24 kV - 115/24kV Power Transformer - 40 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	8	100,000					800,000	23				184
		Cap	24 kV - Capacitor - 5 MVAR	5	60,000					300,000	8				40
		Dct1	24 kV - Disconnects	16	5,000					80,000	1				16
		GDct1	24 kV - Grnd Disconnects	1	12,000					12,000	1				1
		GBnk1	24 kV - Ground Bank	3	261,000					783,000	20				60
		PT1	24 kV - PT	2	3,000					6,000	1				2
	115	Brk3	115 kV - Breakers	2	128,000	256,000					20	40			
		CT3	115 kV - CT	4	35,000	140,000					1	4			
		Dct3	115 kV - Disconnects	10	9,700	97,000					1	10			
		GDct2	115 kV - Grnd Disconnects	2	15,000	30,000					1	2			
		MODct2	115 kV - MODisconnects	2	15,000	30,000					1	2			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						571,000			-	6,981,000		62		-	343
						8%			0%	92%		15%		0%	85%
LaVerendrye	66	Trf3	66 kV - 230/66 kV Power Transformer - 140 MVA	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		Dct2	66 kV - Disconnects	18	8,000				144,000		1			18	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Trf3	115 kV - 230/115 kV Power Transformer - 250 MVA	3	4,000,000	12,000,000					55	165			
		Brk3	115 kV - Breakers	14	128,000	1,792,000					20	280			
		Cap	115 kV - Capacitor 110 MVA	1	1,320,000		1,320,000				8	8			
		CT3	115 kV - CT	5	35,000	175,000					1	5			
		CSw3	115 kV - Circuit Switcher	1	100,000	100,000					15	15			
		Dct3	115 kV - Disconnects	39	9,700	378,300					1	39			
		GDct2	115 kV - Grnd Disconnects	10	15,000	150,000					1	10			
		MODct2	115 kV - MODisconnects	1	15,000	15,000					1	1			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
	230	Brk4	230 kV - Breakers	7	200,000	1,400,000					27	189			
		CT4	230 kV - CT	8	50,000	400,000					3	24			
		Dct4	230 kV - Disconnects	14	12,000	168,000					1	14			
		GDct3	230 kV - Grnd Disconnects	4	18,000	72,000					1	4			
		MODct3	230 kV - MODisconnects	9	18,000	162,000					1	9			
		PT4	230 kV - PT	9	15,000	135,000					4	36			
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	1	100,000	100,000					23	23			
		GBnk1	13.8 Voltage Control - Ground Transformer	1	261,000	261,000					20	20			
		MODct1	13.8 Voltage Control - MODisconnects	1	12,000	12,000					1	1			
		Rctr2	13.8 Voltage Control - Reactor - 30 MVAR	1	2,500,000		2,500,000				20	20			
						17,338,300	3,820,000	-	9,654,000	-		867		261	-
						56%	13%	0%	31%	0%		77%		23%	0%

Sum of Number of Components						Extended Cost						Extended Hours			
					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Letellier	66	Trf2	66 kV - 230/66 kV Power Transformer - 93.3 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		Dct2	66 kV - Disconnects	36	8,000				288,000		1			36	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	6	200,000	1,200,000					27	162			
		CT4	230 kV - CT	6	50,000	300,000					3	18			
		Dct4	230 kV - Disconnects	12	12,000	144,000					1	12			
		GDct3	230 kV - Grnd Disconnects	4	18,000	72,000					1	4			
		MODct3	230 kV - MODisconnects	6	18,000	108,000					1	6			
		PT4	230 kV - PT	9	15,000	135,000					4	36			
						1,959,000			6,898,000	-		238		232	-
						22%			78%	0%		51%		49%	0%
McPHillips Terminal - 1401	24	Trf2	24 kV - 115/24kV Power Transformer - 40 MVA	1	2,500,000					2,500,000	20				20
		Brk1	24 kV - Breakers	11	100,000					1,100,000	23				253
		Dct1	24 kV - Disconnects	34	5,000					170,000	1				34
		GBnk1	24 kV - Ground Bank	2	261,000					522,000	20				40
		PT1	24 kV - PT	2	3,000					6,000	1				2
		Trf2	24 kV - 115/24kV Power Transformer - 30 MVA	1	2,500,000					2,500,000	20				20
		Cap	24 kV - Capacitor - 25MVAR	1	300,000					300,000	8				
	66	Trf2	66 kV - 115/66 kV Power Transformer - 80 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		Dct2	66 kV - Disconnects	12	8,000				96,000		1			12	
		GDct1	66 kV - Grnd Disconnects	4	12,000				48,000		1			4	
		MODct1	66 kV - MODisconnects	6	12,000				72,000		1			6	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Brk3	115 kV - Breakers	10	128,000	1,280,000					20	200			
		CT3	115 kV - CT	7	35,000	245,000					1	7			
		Dct3	115 kV - Disconnects	26	9,700	252,200					1	26			
		GDct2	115 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
		PhSft	115 kV - Phaseshifter 80 MVA	2	4,000,000	8,000,000					55	110			
						9,855,200			5,826,000	7,098,000		351		204	369
						43%			26%	31%		38%		22%	40%

						Extended Cost						Extended Hours			
													Non		
								Non Eligible					Eligible		
Sum of Number of Components					Unit	Tran	Ancillary	Tran	ST	Dist	Maintenance	Tran	Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Mercy	4	Trf1	4 kV - 115/4kV Power Transformer - 13 MVA	2	1,000,000					2,000,000	20				40
	12	Trf2	12 kV - 115/12kV Power Transformer - 28 MVA	2	2,500,000					5,000,000	20				40
		Brk1	12 kV - Breakers	10	100,000					1,000,000	23				230
		Dct1	12 kV - Disconnects	24	5,000					120,000	1				24
		Rclr1	12 kV - Reclosers	5	25,000					125,000	10				50
		Reg1	12 kV - Regulators	3	12,000					36,000	2.5				8
	115	Brk3	115 kV - Breakers	5	128,000	640,000					20	100			
		CT3	115 kV - CT	5	35,000	175,000					1	5			
		Dct3	115 kV - Disconnects	13	9,700	126,100					1	13			
		GDct2	115 kV - Grnd Disconnects	3	15,000	45,000					1	3			
		MODct2	115 kV - MODisconnects	7	15,000	105,000					1	7			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						1,109,100			-	8,281,000		132		-	392
						12%			0%	88%		25%		0%	75%
Mile 13 Stn Flin Flon - 2764	115	Brk3	115 kV - Breakers	1											
		CT3	115 kV - CT	1											
		Dct3	115 kV - Disconnects	3											
		GDct2	115 kV - Grnd Disconnects	1											
		PT3	115 kV - PT	4											
						100%						100%			

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Minitonas	12	Trf1	12 kV - 66/12kV Power Transformer - 5 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV - Disconnects	8	5,000					40,000	1				8
		Rclr1	12 kV - Reclosers	3	25,000					75,000	10				30
	66	Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		Dct2	66 kV - Disconnects	16	8,000				128,000		1			16	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	3	200,000	600,000					27	81			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		Dct4	230 kV - Disconnects	6	12,000	72,000					1	6			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
						1,040,000			9,738,000	1,115,000		121		282	58
						9%			82%	9%		26%		61%	13%
Minnedosa	12	Trf1	12 kV - 115/12kV Power Transformer - 15 MVA	2	1,000,000					2,000,000	20				40
		Brk1	12 kV - Breakers	1	100,000					100,000	23				23
		Dct1	12 kV - Disconnects	18	5,000					90,000	1				18
		MODct1	12 kV - MODisconnects	2	12,000					24,000	1				2
		Rclr1	12 kV - Reclosers	7	25,000					175,000	10				70
	115	Brk3	115 kV - Breakers	3	128,000	384,000					20	60			
		CT3	115 kV - CT	3	35,000	105,000					1	3			
		Dct3	115 kV - Disconnects	10	9,700	97,000					1	10			
		GDct2	115 kV - Grnd Disconnects	2	15,000	30,000					1	2			
		MODct2	115 kV - MODisconnects	3	15,000	45,000					1	3			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						679,000			-	2,389,000		82		-	153
						22%			0%	78%		35%		0%	65%
Mohawk	24	Trf2	24 kV - 115/24kV Power Transformer - 100 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	13	100,000					1,300,000	23				299
		Cap	24 kV - Capacitor - 5 MVAR	2	60,000					120,000	8				16
		CSw1	24 kV - Circuit Switcher	2	40,000					80,000	15				30
		Dct1	24 kV - Disconnects	26	5,000					130,000	1				26
		GDct1	24 kV - Grnd Disconnects	2	12,000					24,000	1				2
		PT1	24 kV - PT	2	3,000					6,000	1				2
	115	Brk3	115 kV - Breakers	6	128,000	768,000					20	120			
		CT3	115 kV - CT	6	35,000	210,000					1	6			
		Dct3	115 kV - Disconnects	12	9,700	116,400					1	12			
		GDct2	115 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		MODct2	115 kV - MODisconnects	6	15,000	90,000					1	6			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						1,262,400			-	6,660,000		152		-	415
						16%			0%	84%		27%		0%	73%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Mystery	24	Trf2	24 kV - 115/24kV Power Transformer - 20 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	10	100,000					1,000,000	23				230
	138	Trf3	138 kV - 230/138 kV Power Transformer - 250 MVA	2	4,000,000	8,000,000					55	110			
		Brk3	138 kV - Breakers	4	128,000	512,000					20	80			
		CT3	138 kV - CT	4	35,000	140,000					1	4			
		Dct3	138 kV - Disconnects	11	9,700	106,700					1	11			
		GDct2	138 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		MODct2	138 kV - MODisconnects	2	15,000	30,000					1	2			
		PT3	138 kV - PT	2	9,000	18,000					2	4			
	230	Brk4	230 kV - Breakers	4	200,000	800,000					27	108			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		Dct4	230 kV - Disconnects	8	12,000	96,000					1	8			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	4	100,000	400,000					23	92			
		Dct1	13.8 Voltage Control - Disconnects	6	5,000	30,000					1	6			
		PT1	13.8 Voltage Control - PT	2	3,000	6,000					1	2			
		Rctr2	13.8 Voltage Control - Reactor - 20 MVAR	2	2,500,000		5,000,000				20	40			
						10,566,700	5,000,000	-	-	6,000,000		505		-	270
						49%	23%	0%	0%	28%		65%		0%	35%
Neepawa	12	Trf1	12 kV - 115/12kV Power Transformer - 10 MVA	2	1,000,000					2,000,000	20				40
		Brk1	12 kV - Breakers	1	100,000					100,000	23				23
		Dct1	12 kV - Disconnects	14	5,000					70,000	1				14
		MODct1	12 kV - MODisconnects	2	12,000					24,000	1				2
		PT1	12 kV - PT	2	3,000					6,000	1				2
		Rclr1	12 kV - Reclosers	6	25,000					150,000	10				60
	66	Trf2	66 kV - 115/66 kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Trf2	66 kV - 115/66 kV Power Transformer - 90 MVA	1	2,500,000				2,500,000		20			20	
		Brk2	66 kV - Breakers	7	100,000				700,000		23			161	
		Dct2	66 kV - Disconnects	20	8,000				160,000		1			20	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Brk3	115 kV - Breakers	8	128,000	1,024,000					20	160			
		Cap	115 kV - Capacitor 25 MVA	1	300,000		300,000				8	8			
		CT3	115 kV - CT	8	35,000	280,000					1	8			
		CSw3	115 kV - Circuit Switcher	1	100,000	100,000					15	15			
		Dct3	115 kV - Disconnects	22	9,700	213,400					1	22			
		GDct2	115 kV - Grnd Disconnects	7	15,000	105,000					1	7			
		MODct2	115 kV - MODisconnects	5	15,000	75,000					1	5			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						1,815,400	300,000	-	9,370,000	2,350,000		229		259	141
						13%	2%	0%	68%	17%		36%		41%	22%

Sum of Number of Components Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Extended Cost Tran Cost	Extended Cost Ancillary Cost	Extended Cost Non Eligible Tran Cost	Extended Cost ST Cost	Extended Cost Dist Cost	Maintenance Hours	Extended Hours Tran Cost	Extended Hours Non Eligible Tran Cost	Extended Hours ST Cost	Extended Hours Ddst Cost
Overflowing River	230	Brk4	230 kV - Breakers	3	200,000	600,000									
		CT4	230 kV - CT	3	50,000	150,000									
		Dct4	230 kV - Disconnects	6	12,000	72,000									
		GDct3	230 kV - Grnd Disconnects	3	18,000	54,000									
		MODct3	230 kV - MODisconnects	4	18,000	72,000									
		PT4	230 kV - PT	6	15,000	90,000									
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	3	100,000	300,000									
		Trf2	13.8 Voltage Control - 230/13.8 kV Power Transformer -	1	2,500,000	2,500,000									
		Dct1	13.8 Voltage Control - Disconnects	4	5,000	20,000									
		PT1	13.8 Voltage Control - PT	1	3,000	3,000									
		Rctr2	13.8 Voltage Control - Reactor - 20 MVAR	2	2,500,000		5,000,000								
						3,861,000	5,000,000	-	-	-					
						44%	56%	0%	0%	0%		100%			
Parkdale	12	Trf2	12 kV - 115/12kV Power Transformer - 25 MVA	1	2,500,000					2,500,000	20				20
		Trf1	12 kV - 33/12kV Power Transformer - 1.5 MVA	1	1,000,000					1,000,000	20				20
		Brk1	12 kV - Breakers	1	100,000					100,000	23				23
		Dct1	12 kV - Disconnects	10	5,000					50,000	1				10
		PT1	12 kV - PT	1	3,000					3,000	1				1
		Rclr1	12 kV - Reclosers	4	25,000					100,000	10				40
	33	Trf2	33 kV - 115/33kV Power Transformer - 20 MVA	4	2,500,000				10,000,000		20			80	
		Brk1	33 kV - Breakers	6	100,000				600,000		23			138	
		Dct1	33 kV - Disconnects	34	5,000				170,000		1			34	
		GBnk1	33 kV - Ground Bank	1	261,000				261,000		20			20	
		PT1	33 kV - PT	5	3,000				15,000		1			5	
	66	Trf2	66 kV - 115/66 kV Power Transformer - 20 MVA	4	2,500,000				10,000,000		20			80	
		Brk2	66 kV - Breakers	7	100,000				700,000		23			161	
		Dct2	66 kV - Disconnects	29	8,000				232,000		1			29	
		GBnk2	66 kV - Ground Bank	1	500,000				500,000		7			7	
	115	Brk3	115 kV - Breakers	11	128,000	1,408,000					20	220			
		CT3	115 kV - CT	11	35,000	385,000					1	11			
		Dct3	115 kV - Disconnects	28	9,700	271,600					1	28			
		GDct2	115 kV - Grnd Disconnects	13	15,000	195,000					1	13			
		MODct2	115 kV - MODisconnects	14	15,000	210,000					1	14			
		PT3	115 kV - PT	10	9,000	90,000					2	20			
						2,559,600	-	-	22,478,000	3,753,000		306		554	114
						9%	0%	0%	78%	13%		31%		57%	12%

Sum of Number of Components						Extended Cost						Extended Hours			
					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Plessis	24	Trf2	24 kV - 115/24kV Power Transformer - 100 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	13	100,000					1,300,000	23				299
		Cap	24 kV - Capacitor - 5 MVAR	4	60,000					240,000	8				32
		CT1	24 kV - CT	18	8,000					144,000	1				18
		CSw1	24 kV - Circuit Switcher	2	40,000					80,000	15				30
		Dct1	24 kV - Disconnects	31	5,000					155,000	1				31
		GDct1	24 kV - Grnd Disconnects	2	12,000					24,000	1				2
		MODct1	24 kV - MODisconnects	1	12,000					12,000	1				1
		PT1	24 kV - PT	2	3,000					6,000	1				2
	115	Brk3	115 kV - Breakers	1	128,000	128,000					20	20			
		CT3	115 kV - CT	1	35,000	35,000					1	1			
		Dct3	115 kV - Disconnects	6	9,700	58,200					1	6			
		GDct2	115 kV - Grnd Disconnects	2	15,000	30,000					1	2			
		MODct2	115 kV - MODisconnects	4	15,000	60,000					1	4			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						329,200	-	-	-	6,961,000		37		-	455
						5%	0%	0%	0%	95%		8%		0%	92%
Ponton - 2699	230	Brk4	230 kV - Breakers	5	200,000	1,000,000									
		CT4	230 kV - CT	5	50,000	250,000									
		Dct4	230 kV - Disconnects	11	12,000	132,000									
		GDct3	230 kV - Grnd Disconnects	4	18,000	72,000									
		MODct3	230 kV - MODisconnects	4	18,000	72,000									
		PT4	230 kV - PT	6	15,000	90,000									
	13.8 Voltag	Trf2	13.8 Voltage Control - 230/13.8/9.3 kV Power Transform	1	2,500,000	2,500,000									
		Dct1	13.8 Voltage Control - Disconnects	3	5,000	15,000									
		PT1	13.8 Voltage Control - PT	2	3,000	6,000									
		SVC	13.8 Voltage Control - SVC Thyristor controlled	1	n/a										
		HFtr	13.8 Voltage Control - Harmonic Filter 67.63 MVAR	1	n/a										
		Cap	13.8 Voltage Control - Capacitor - 54 MVAR	1	648,000		648,000								
		Rctr2	13.8 Voltage Control - Reactor - 88.3 MVAR	1	2,500,000		2,500,000								
						4,137,000	3,148,000	-	-	-					
						57%	43%	0%	0%	0%		100%			

Sum of Number of Components						Extended Cost						Extended Hours			
					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Portage Sask	4	Trf1	4 kV - 66/4kV Power Transformer - 10 MVA	2	1,000,000					2,000,000	20				40
		CT1	4 kV - CT	2	8,000					16,000	1				2
		Dct1	4 kV - Disconnects	5	5,000					25,000	1				5
		Rclr1	4 kV - Reclosers	2	25,000					50,000	10				20
		Reg1	4 kV - Regulator	2	12,000					24,000	2.5				5
	12	Trf1	12 kV - 66/12kV Power Transformer - 5 MVA	2	1,000,000					2,000,000	20				40
		Dct1	12 kV - Disconnects	17	5,000					85,000	1				17
		Rclr1	12 kV - Reclosers	7	25,000					175,000	10				70
	66	Trf2	66 kV - 115/66 kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	7	100,000				700,000		23			161	
		CT2	66 kV - CT	14	12,000				168,000		1			14	
		Dct2	66 kV - Disconnects	22	8,000				176,000		1			22	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Brk3	115 kV - Breakers	6	128,000	768,000					20	120			
		CT3	115 kV - CT	6	35,000	210,000					1	6			
		Dct3	115 kV - Disconnects	14	9,700	135,800					1	14			
		GDct2	115 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		MODct2	115 kV - MODisconnects	6	15,000	90,000					1	6			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						1,281,800	-	-	7,054,000	4,375,000		154		255	199
						10%	0%	0%	56%	34%		25%		42%	33%
Portage South	66	Trf2	66 kV - 230/66 kV Power Transformer - 50 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		CT2	66 kV - CT	7	12,000				84,000		1			7	
		Dct2	66 kV - Disconnects	28	8,000				224,000		1			28	
		GDct1	66 kV - Grnd Disconnects	3	12,000				36,000		1			3	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	4	200,000	800,000					27	108			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		Dct4	230 kV - Disconnects	8	12,000	96,000					1	8			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
						1,264,000	-	-	6,954,000	-		150		234	-
						15%	0%	0%	85%	0%		39%		61%	0%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Rall's Island - 2638	12	Trf2	12 kV - 115/12kV Power Transformer - 25 MVA	3	2,500,000					7,500,000	20				60
		Brk1	12 kV - Breakers	6	100,000					600,000	23				138
		Dct1	12 kV - Disconnects	30	5,000					150,000	1				30
		PT1	12 kV - PT	3	3,000					9,000	1				3
		Rclr1	12 kV - Reclosers	9	25,000					225,000	10				90
	66	Trf1	66 kV - 12/66 kV Step Up Transformer - 10 MVA	2	1,000,000				2,000,000		20			40	
		MODct1	66 kV - MODisconnects	2	12,000				24,000		1			2	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	5	200,000	1,000,000					27	135			
		CT4	230 kV - CT	5	50,000	250,000					3	15			
		CSW4	230 kV - Curicuit Switcher	1	150,000	150,000					15	15			
		Dct4	230 kV - Disconnects	10	12,000	120,000					1	10			
		GDct3	230 kV - Grnd Disconnects	3	18,000	54,000					1	3			
		MODct3	230 kV - MODisconnects	7	18,000	126,000					1	7			
		PT4	230 kV - PT	8	15,000	120,000					4	32			
		Rctr2	230 kV - Reactor 30 MVAR	1	2,500,000		2,500,000				20	20			
						1,820,000	2,500,000	-	2,034,000	8,484,000		237		46	321
						12%	17%	0%	14%	57%		39%		8%	53%
Raven - Lake 2591	12	PT1	12 kV - PT	1	3,000					3,000	1				1
	33	Trf2	33 kV - 115/33kV Power Transformer - 20 MVA	2	2,500,000				5,000,000		20			40	
		Brk1	33 kV - Breakers	4	100,000				400,000		23			92	
		Dct1	33 kV - Disconnects	12	5,000				60,000		1			12	
		GBnk1	33 kV - Ground Bank	2	261,000				522,000		20			40	
	115	Trf3	115 kV - 230/115 kV Power Transformer - 110 MVA	1	4,000,000	4,000,000					55	55			
		Brk3	115 kV - Breakers	5	128,000	640,000					20	100			
		CT3	115 kV - CT	5	35,000	175,000					1	5			
		Dct3	115 kV - Disconnects	11	9,700	106,700					1	11			
		GDct2	115 kV - Grnd Disconnects	1	15,000	15,000					1	1			
		MODct2	115 kV - MODisconnects	4	15,000	60,000					1	4			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
	230	Brk4	230 kV - Breakers	2	200,000	400,000					27	54			
		Dct4	230 kV - Disconnects	4	12,000	48,000					1	4			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	3	18,000	54,000					1	3			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
	13.8 Voltag	Trf2	13.8 Voltage Control - 230/13.8 kV Power Transformer -	3	2,500,000	7,500,000					20	60			
		Cap	13.8 Voltage Control - Capacitor - 12 MVAR	2	144,000		288,000				8	16			
		Dct1	13.8 Voltage Control - Disconnects	3	5,000	15,000					1	3			
		PT1	13.8 Voltage Control - PT	1	3,000	3,000					1	1			
						13,130,700	288,000	-	5,982,000	3,000		339		184	1
						68%	1%	0%	31%	0%		65%		35%	0%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Reston - 2039	12	Trf1	12 kV - 66/12kV Power Transformer - 10 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV - Disconnects	8	5,000					40,000	1				8
		PT1	12 kV - PT	1	3,000					3,000	1				1
		Rclr1	12 kV - Reclosers	3	25,000					75,000	10				30
	66	Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		CT2	66 kV - CT	9	12,000				108,000		1			9	
		Dct2	66 kV - Disconnects	21	8,000				168,000		1			21	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	4	200,000	800,000					27	108			
		CT4	230 kV - CT	5	50,000	250,000					3	15			
		CSW4	230 kV - Curicuit Switcher	1	150,000	150,000					15	15			
		Dct4	230 kV - Disconnects	9	12,000	108,000					1	9			
		GDct3	230 kV - Grnd Disconnects	3	18,000	54,000					1	3			
		MODct3	230 kV - MODisconnects	5	18,000	90,000					1	5			
		PT4	230 kV - PT	7	15,000	105,000					4	28			
		Rctr2	230 kV - Reactor 30 MVAR	1	2,500,000		2,500,000				20	20			
						1,557,000	2,500,000	-	9,786,000	1,118,000		203		273	59
						10%	17%	0%	65%	8%		38%		51%	11%
Richer South - 2756	66	Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	4	100,000				400,000		23			92	
		CT2	66 kV - CT	4	12,000				48,000		1			4	
		Dct2	66 kV - Disconnects	17	8,000				136,000		1			17	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	4	200,000	800,000					27	108			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		CSW4	230 kV - Curicuit Switcher	1	150,000	150,000					15	15			
		Dct4	230 kV - Disconnects	13	12,000	156,000					1	13			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	5	15,000	75,000					4	20			
		Rctr2	230 kV - Reactor 50 MVAR	1	2,500,000		2,500,000				20	20			
						1,489,000	2,500,000	-	9,594,000	-		194		241	-
						11%	18%	0%	71%	0%		45%		55%	0%

Sum of Number of Components						Extended Cost						Extended Hours			
								Non Eligible					Non Eligible		
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Tran Cost	ST Cost	Ddst Cost
Rideway - 1076	12	Trf1	12 kV - 66/12kV Power Transformer - 11.25 MVA	1	1,000,000					1,000,000	20				20
	66	Trf3	66 kV - 230/66 kV Power Transformer - 125 MVA	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	7	100,000				700,000		23			161	
		CT2	66 kV - CT	11	12,000				132,000		1			11	
		Dct2	66 kV - Disconnects	14	8,000				112,000		1			14	
		GDct1	66 kV - Grnd Disconnects	2	12,000				24,000		1			2	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		MODct1	66 kV - MODisconnects	7	12,000				84,000		1			7	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	6	200,000	1,200,000					27	162			
		CT4	230 kV - CT	7	50,000	350,000					3	21			
		Dct4	230 kV - Disconnects	12	12,000	144,000					1	12			
		GDct3	230 kV - Grnd Disconnects	5	18,000	90,000					1	5			
		MODct3	230 kV - MODisconnects	7	18,000	126,000					1	7			
		PT4	230 kV - PT	7	15,000	105,000					4	28			
						2,015,000	-	-	10,062,000	1,000,000		235		323	20
						15%	0%	0%	77%	8%		41%		56%	3%
Roblin South - 2676	66	Trf2	66 kV - 230/66 kV Power Transformer - 50 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		Cap	66 kV - Capacitor - 10 MVAR	1	120,000				120,000		8			8	
		CSw2	66 kV - Circuit Switcher	1	70,000				70,000		15			15	
		CT2	66 kV - CT	9	12,000				108,000		1			9	
		Dct2	66 kV - Disconnects	17	8,000				136,000		1			17	
		GDct1	66 kV - Grnd Disconnects	1	12,000				12,000		1			1	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	4	200,000	800,000					27	108			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		CSW4	230 kV - Curicuit Switcher	1	150,000	150,000					15	15			
		Dct4	230 kV - Disconnects	9	12,000	108,000					1	9			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	5	15,000	75,000					4	20			
		Rctr2	230 kV - Reactor 20 MVAR	1	2,500,000		2,500,000				20	20			
						1,441,000	2,500,000	-	6,956,000	-		190		223	-
						13%	23%	0%	64%	0%		46%		54%	0%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Rosenfeld - 2076	33	Brk1	33 kV - Breakers	2	100,000				200,000		23			46	
		CT1	33 kV - CT	4	8,000				32,000		1			4	
		Dct1	33 kV - Disconnects	5	5,000				25,000		1			5	
		PT1	33 kV - PT	1	3,000				3,000		1			1	
	66	Trf2	66 kV - 230/66 kV Power Transformer - 20 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		CT2	66 kV - CT	11	12,000				132,000		1			11	
		Dct2	66 kV - Disconnects	14	8,000				112,000		1			14	
		GBnk2	66 kV - Ground Bank	1	500,000				500,000		7			7	
		PT2	66 kV - PT	1	5,000				5,000		2			2	
	115	Brk3	115 kV - Breakers	4	128,000	512,000					20	80			
		CT3	115 kV - CT	4	35,000	140,000					1	4			
		Dct3	115 kV - Disconnects	14	9,700	135,800					1	14			
		GDct2	115 kV - Grnd Disconnects	2	15,000	30,000					1	2			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						835,800	-	-	6,509,000	-		104		245	-
						11%	0%	0%	89%	0%		30%		70%	0%
Ross Lake - 2719	12	Trf2	12 kV - 115/12kV Power Transformer - 56 MVA	2	2,500,000					5,000,000	20				40
		Brk1	12 kV - Breakers	12	100,000					1,200,000	23				276
		CT1	12 kV - CT	4	8,000					32,000	1				4
		Dct1	12 kV - Disconnects	22	5,000					110,000	1				22
		GBnk1	12 kV - Ground Bank	1	261,000					261,000	20				20
		PT1	12 kV - PT	2	3,000					6,000	1				2
		Rclr1	12 kV - Reclosers	1	25,000					25,000	10				10
	115	Brk3	115 kV - Breakers	6	128,000	768,000					20	120			
		CT3	115 kV - CT	6	35,000	210,000					1	6			
		Dct3	115 kV - Disconnects	18	9,700	174,600					1	18			
		GDct2	115 kV - Grnd Disconnects	4	15,000	60,000					1	4			
		MODct2	115 kV - MODisconnects	2	15,000	30,000					1	2			
		PT3	115 kV - PT	6	9,000	54,000					2	12			
						1,296,600	-	-	-	6,634,000		162		-	374
						16%	0%	0%	0%	84%		30%		0%	70%

Sum of Number of Components

Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Extended Cost: Tran Cost	Extended Cost: Ancillary Cost	Extended Cost: Non Eligible Tran Cost	Extended Cost: ST Cost	Extended Cost: Dist Cost	Maintenance Hours	Extended Hours: Tran Cost	Extended Hours: Non Eligible Tran Cost	Extended Hours: ST Cost	Extended Hours: Ddst Cost
Rosser - 1059	66	Trf2	66 kV - 115/66 kV Power Transformer - 40 MVA	1	2,500,000				2,500,000		20			20	
		Brk2	66 kV - Breakers	3	100,000				300,000		23			69	
		CT2	66 kV - CT	5	12,000				60,000		1			5	
		Dct2	66 kV - Disconnects	13	8,000				104,000		1			13	
		GBnk2	66 kV - Ground Bank	1	500,000				500,000		7			7	
		PT2	66 kV - PT	1	5,000				5,000		2			2	
	115	Trf3	115 kV - 230/115 kV Power Transformer - 176 MVA	2	4,000,000	8,000,000					55	110			
		Trf3	115 kV - 230/115 kV Power Transformer - 250 MVA	1	4,000,000	4,000,000					55	55			
		Trf3	115 kV - 230/115 kV Power Transformer - 285 MVA	1	4,000,000	4,000,000					55	55			
		Brk3	115 kV - Breakers	18	128,000	2,304,000					20	360			
		Cap	115 kV - Capacitor 110 MVA	1	1,320,000		1,320,000				8	8			
		CT3	115 kV - CT	6	35,000	210,000					1	6			
		CSw3	115 kV - Circuit Switcher	1	100,000	100,000					15	15			
		Dct3	115 kV - Disconnects	51	9,700	494,700					1	51			
		GDct2	115 kV - Grnd Disconnects	13	15,000	195,000					1	13			
		MODct2	115 kV - MODisconnects	1	15,000	15,000					1	1			
		PT3	115 kV - PT	6	9,000	54,000					2	12			
	230	Brk4	230 kV - Breakers	8	200,000	1,600,000					27	216			
		CT4	230 kV - CT	10	50,000	500,000					3	30			
		Dct4	230 kV - Disconnects	16	12,000	192,000					1	16			
		GDct3	230 kV - Grnd Disconnects	5	18,000	90,000					1	5			
		MODct3	230 kV - MODisconnects	10	18,000	180,000					1	10			
		PT4	230 kV - PT	13	15,000	195,000					4	52			
	13.8 Voltag	Brk1	13.8 Voltage Control - 13.8 Breakers	9	100,000	900,000					23	207			
		Dct1	13.8 Voltage Control - Disconnects	9	5,000	45,000					1	9			
		PT1	13.8 Voltage Control - PT	4	3,000	12,000					1	4			
		Rctr2	13.8 Voltage Control - Reactor - 20 MVAR	6	2,500,000		15,000,000				20	120			
						23,086,700	16,320,000	-	3,469,000	-		1,355		116	-
						54%	38%	0%	8%	0%		92%		8%	0%
Selkirk Sw. Stn.	24	Trf2	24 kV - 115/24kV Power Transformer - 100 MVA	1	2,500,000					2,500,000	20				20
		Dct1	24 kV - Disconnects	2	5,000					10,000	1				2
	115	Brk3	115 kV - Breakers	14	128,000	1,792,000					20	280			
		CT3	115 kV - CT	16	35,000	560,000					1	16			
		Dct3	115 kV - Disconnects	28	9,700	271,600					1	28			
		GDct2	115 kV - Grnd Disconnects	6	15,000	90,000					1	6			
		MODct2	115 kV - MODisconnects	9	15,000	135,000					1	9			
		PT3	115 kV - PT	8	9,000	72,000					2	16			
						2,920,600	-	-	-	2,510,000		355		-	22
						54%	0%	0%	0%	46%		94%		0%	6%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
St James - 1026	4	Trf1	4 kV - 24/4kV Power Transformer - 3 MVA	3	1,000,000					3,000,000	20				60
		Brk1	4 kV - Breakers	17	100,000					1,700,000	23				391
		Dct1	4 kV - Disconnects	14	5,000					70,000	1				14
		Reg1	4 kV - Regulator	9	12,000					108,000	2.5				23
	24	Trf2	24 kV - 115/24kV Power Transformer - 100 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	13	100,000					1,300,000	23				299
		CT1	24 kV - CT	13	8,000					104,000	1				13
		CSw1	24 kV - Circuit Switcher	1	40,000					40,000	15				15
		Dct1	24 kV - Disconnects	26	5,000					130,000	1				26
		GDct1	24 kV - Grnd Disconnects	1	12,000					12,000	1				1
		PT1	24 kV - PT	2	3,000					6,000	1				2
	115	Brk3	115 kV - Breakers	4	128,000	512,000					20	80			
		CT3	115 kV - CT	2	35,000	70,000					1	2			
		GDct2	115 kV - Grnd Disconnects	14	15,000	210,000					1	14			
		MODct2	115 kV - MODisconnects	9	15,000	135,000					1	9			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
						945,000	-	-	-	11,470,000		109		-	884
						8%	0%	0%	0%	92%		11%		0%	89%
St Leon - 2703	66	Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	5	100,000				500,000		23			115	
		CT2	66 kV - CT	9	12,000				108,000		1			9	
		Dct2	66 kV - Disconnects	17	8,000				136,000		1			17	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	6	200,000	1,200,000					27	162			
		CT4	230 kV - CT	9	50,000	450,000					3	27			
		Dct4	230 kV - Disconnects	16	12,000	192,000					1	16			
		GDct3	230 kV - Grnd Disconnects	4	18,000	72,000					1	4			
		MODct3	230 kV - MODisconnects	3	18,000	54,000					1	3			
		PT4	230 kV - PT	8	15,000	120,000					4	32			
						2,088,000	-	-	9,754,000	-		244		269	-
						18%	0%	0%	82%	0%		48%		52%	0%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
St Vital - 1406	24	Trf2	24 kV - 115/24kV Power Transformer - 40 MVA	2	2,500,000					5,000,000	20				40
		Brk1	24 kV - Breakers	9	100,000					900,000	23				207
		Cap	24 kV - Capacitor - 18 MVAR	1	216,000					216,000	8				8
		Cap	24 kV - Capacitor - 9 MVAR	1	108,000					108,000	8				8
		CT1	24 kV - CT	11	8,000					88,000	1				11
		CSw1	24 kV - Circuit Switcher	1	40,000					40,000	15				15
		Dct1	24 kV - Disconnects	21	5,000					105,000	1				21
		GDct1	24 kV - Grnd Disconnects	2	12,000					24,000	1				2
		GBnk1	24 kV - Ground Bank	3	261,000					783,000	20				60
		MODct1	24 kV - MODisconnects	1	12,000					12,000	1				1
		PT1	24 kV - PT	2	3,000					6,000	1				2
	66	Trf2	66 kV - 115/66 kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		CT2	66 kV - CT	9	12,000				108,000		1			9	
		Dct2	66 kV - Disconnects	24	8,000				192,000		1			24	
		GBnk2	66 kV - Ground Bank	1	500,000				500,000		7			7	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Trf2	115 kV - 230/115 kV Power Transformer - 40 MVA	3	2,500,000	7,500,000					20	60			
		Brk3	115 kV - Breakers	19	128,000	2,432,000					20	380			
		Cap	115 kV - Capacitor 110 MVA	1	1,320,000		1,320,000				8	8			
		CT3	115 kV - CT	8	35,000	280,000					1	8			
		CSw3	115 kV - Circuit Switcher	1	100,000	100,000					15	15			
		Dct3	115 kV - Disconnects	54	9,700	523,800					1	54			
		GDct2	115 kV - Grnd Disconnects	11	15,000	165,000					1	11			
		PT3	115 kV - PT	6	9,000	54,000					2	12			
	230	Brk4	230 kV - Breakers	6	200,000	1,200,000					27	162			
		CT4	230 kV - CT	6	50,000	300,000					3	18			
		Dct4	230 kV - Disconnects	12	12,000	144,000					1	12			
		GDct3	230 kV - Grnd Disconnects	3	18,000	54,000					1	3			
		MODct3	230 kV - MODisconnects	6	18,000	108,000					1	6			
		PT4	230 kV - PT	6	15,000	90,000					4	24			
						12,950,800	1,320,000	-	6,410,000	7,282,000		773		222	375
						46%	5%	0%	23%	26%		56%		16%	27%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Transcona - 1403	66	Trf2	66 kV - 115/66 kV Power Transformer - 40 MVA	4	2,500,000				10,000,000		20			80	
		Trf2	66 kV - 115/66 kV Power Transformer - 80 MVA	1	2,500,000				2,500,000		20			20	
		Brk2	66 kV - Breakers	13	100,000				1,300,000		23			299	
		CT2	66 kV - CT	13	12,000				156,000		1			13	
		Dct2	66 kV - Disconnects	38	8,000				304,000		1			38	
		GDct1	66 kV - Grnd Disconnects	7	12,000				84,000		1			7	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Brk3	115 kV - Breakers	13	128,000	1,664,000					20	260			
		CT3	115 kV - CT	5	35,000	175,000					1	5			
		Dct3	115 kV - Disconnects	36	9,700	349,200					1	36			
		GDct2	115 kV - Grnd Disconnects	8	15,000	120,000					1	8			
		PT3	115 kV - PT	10	9,000	90,000					2	20			
						2,398,200	-	-	14,354,000	-		329		461	-
						14%	0%	0%	86%	0%		42%		58%	0%
Virden - 2762	66	Trf3	66 kV - 230/66 kV Power Transformer - includes 6 surge	2	4,000,000				8,000,000		55			110	
		Brk2	66 kV - Breakers	6	100,000				600,000		23			138	
		CT2	66 kV - CT	10	12,000				120,000		1			10	
		Dct2	66 kV - Disconnects	22	8,000				176,000		1			22	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	230	Brk4	230 kV - Breakers	2	200,000	400,000					27	54			
		CT4	230 kV - CT	4	50,000	200,000					3	12			
		Dct4	230 kV - Disconnects	4	12,000	48,000					1	4			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	3	15,000	45,000					4	12			
						801,000	-	-	9,906,000	-		88		298	-
						7%	0%	0%	93%	0%		23%		77%	0%
Whiteshell SK1 Stn	115	Brk3	115 kV - Breakers	1											
		CT3	115 kV - CT	1											
		Dct3	115 kV - Disconnects	3											
		GDct3	115 kV - Grnd Disconnects	1											
		PT3	115 kV - PT	1											
		Reg1	115 kV - Regulator 75 MVA	1											
						100%						100%			

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Whiteshell Stn - 2167	12	Trf1	12 kV - 115/12kV Power Transformer - 11.25 MVA	1	1,000,000					1,000,000	20				20
		Trf1	12 kV - 33/12kV Power Transformer - 1.5 MVA	2	1,000,000					2,000,000	20				40
		Dct1	12 kV - Disconnects	11	5,000					55,000	1				11
		PT2	12 kV - PT	1	5,000					5,000	2				2
		Rclr1	12 kV - Reclosers	3	25,000					75,000	10				30
		Reg1	12 kV - Regulators	2	12,000					24,000	2.5				5
	33	Trf2	33 kV - 115/33kV Power Transformer - 25 MVA	1	2,500,000				2,500,000		20			20	
		Trf2	33 kV - 115/33kV Power Transformer - 30 MVA	1	2,500,000				2,500,000		20			20	
		Brk1	33 kV - Breakers	9	100,000				900,000		23			207	
		CT1	33 kV - CT	10	8,000				80,000		1			10	
		Dct1	33 kV - Disconnects	24	5,000				120,000		1			24	
		GBnk1	33 kV - Ground Bank	2	261,000				522,000		20			40	
		PT1	33 kV - PT	3	3,000				9,000		1			3	
	115	Trf3	115 kV - 230/115 kV Power Transformer - 250 MVA	2	4,000,000	8,000,000					55	110			
		Brk3	115 kV - Breakers	9	128,000	1,152,000					20	180			
		CT3	115 kV - CT	12	35,000	420,000					1	12			
		Dct3	115 kV - Disconnects	14	9,700	135,800					1	14			
		GDct2	115 kV - Grnd Disconnects	5	15,000	75,000					1	5			
		MODct2	115 kV - MODisconnects	10	15,000	150,000					1	10			
		PhSft	115 kV - Phaseshifter 200 MVA	2	4,000,000	8,000,000					55	110			
		PT3	115 kV - PT	2	9,000	18,000					2	4			
	230	Brk4	230 kV - Breakers	2	200,000	400,000					27	54			
		CT4	230 kV - CT	2	50,000	100,000					3	6			
		GDct3	230 kV - Grnd Disconnects	2	18,000	36,000					1	2			
		MODct3	230 kV - MODisconnects	4	18,000	72,000					1	4			
		PT4	230 kV - PT	4	15,000	60,000					4	16			
						18,618,800	-	-	6,631,000	3,159,000		527		324	108
						66%	0%	0%	23%	11%		55%		34%	11%
Amy (6) - 1506	4 kV	Brk1	4 kV-Breakers	8	100,000					800,000	23				184
		Dct1	4 kV-Disconnects	20	5,000					100,000	1				20
		GDct1	4 kV-Grnd Disconnects	5	12,000					60,000	1				5
		MODct1	4 kV-MODisconnects	3	12,000					36,000	1				3
		PT1	4 kV-PTs	5	3,000					15,000	1				5
	69 kV	Brk2	69 kV-Breakers	17	100,000				1,700,000		23			391	
		Dct2	69 kV-Disconnects	10	8,000				80,000		1			10	
		PT2	69 kV-PT	2	5,000				10,000		2			4	
						-	-	-	1,790,000	1,011,000		-		405	217
						0%	0%	0%	64%	36%		0%		65%	35%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Edmonton (21) - 1521	4 kV	Trf1	4 kV-66/4kV Power Transformer 7.5 MVA	2	1,000,000					2,000,000	20				40
		Brk1	4 kV-Breakers	18	100,000					1,800,000	23				414
		Dct1	4 kV-Disconnects	27	5,000					135,000	1				27
		PT1	4 kV-PTs	19	3,000					57,000	1				19
		Rctr1	4 kV-Reactor 7.5 MVA	1	1,000,000					1,000,000	20				20
		Reg1	4 kV-Regulators	2	12,000					24,000	2.5				5
	12 kV	Trf1	12 kV-66/12kV Power Transformer - 13.3 MVA	4	1,000,000					4,000,000	20				80
		Brk1	12 kV-Breakers	24	100,000					2,400,000	23				552
		Dct1	12 kV-Disconnects	12	5,000					60,000	1				12
		PT1	12 kV-PT	4	3,000					12,000	1				4
	66 kV	Brk2	66 kV-Breakers	3	100,000				300,000		23			69	
		Dct2	66 kV-Disconnects	6	8,000				48,000		1			6	
		GDct2	66 kV-Grnd Disconnects	3	15,000				45,000		1			3	
		MODct1	66 kV-MODisconnects	9	12,000				108,000		1			9	
						-	-	-	501,000	11,488,000		-		87	1,173
						0%	0%	0%	4%	96%		0%		7%	93%
Jessie (22) - 1522	4 kV	Trf1	4 kV-66/4kV Power Transformer 7.5 MVA	4	1,000,000					4,000,000	20				80
		Brk1	4 kV-Breakers	34	100,000					3,400,000	23				782
		Dct1	4 kV-Disconnects	34	5,000					170,000	1				34
		PT1	4 kV-PTs	26	3,000					78,000	1				26
		Rctr1	4 kV-Reactor	3	1,000,000					3,000,000	20				60
		Reg1	4 kV-Regulators	11	12,000					132,000	2.5				28
	12 kV	Trf1	12 kV-66/12kV Power Transformer - 16.6 MVA	2	1,000,000					2,000,000	20				40
		Brk1	12 kV-Breakers	11	100,000					1,100,000	23				253
		Dct1	12 kV-Disconnects	6	5,000					30,000	1				6
		PT1	12 kV-PT	12	3,000					36,000	1				12
	66 kV	Brk2	66 kV-Breakers	4	100,000				400,000		23			92	
		Dct2	66 kV-Disconnects	6	8,000				48,000		1			6	
		GDct2	66 kV-Grnd Disconnects	3	15,000				45,000		1			3	
		MODct1	66 kV-MODisconnects	9	12,000				108,000		1			9	
						-	-	-	601,000	13,946,000		-		110	1,321
						0%	0%	0%	4%	96%		0%		8%	92%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Logan (23) - 1523	4 kV	Trf1	4 kV-66/4kV Power Transformer 7.5 MVA	6	1,000,000					6,000,000	20				120
		Brk1	4 kV-Breakers	46	100,000					4,600,000	23				1,058
		Dct1	4 kV-Disconnects	56	5,000					280,000	1				56
		PT1	4 kV-PTs	16	3,000					48,000	1				16
		Reg1	4 kV-Regulators	7	12,000					84,000	2.5				18
	66 kV	Brk2	66 kV-Breakers	8	100,000				800,000		23			184	
		Dct2	66 kV-Disconnects	16	8,000				128,000		1			16	
		GDct2	66 kV-Grnd Disconnects	5	15,000				75,000		1			5	
		MODct1	66 kV-MODisconnects	11	12,000				132,000		1			11	
						-	-	-	1,135,000	11,012,000		-		216	1,268
						0%	0%	0%	9%	91%		0%		15%	85%
Rover (3) - 1503	4 kV	Trf1	4 kV-66/4kV Power Transformer 9.375 MVA	3	1,000,000					3,000,000	20				60
		Brk1	4 kV-Breakers	19	100,000					1,900,000	23				437
		Dct1	4 kV-Disconnects	40	5,000					200,000	1				40
		PT1	4 kV-PTs	6	3,000					18,000	1				6
		Reg1	4 kV-Regulators	2	12,000					24,000	2.5				5
	12 kV	Trf1	12 kV-66/12kV Power Transformer - 15 MVA	3	1,000,000					3,000,000	20				60
		Brk1	12 kV-Breakers	14	100,000					1,400,000	23				322
		Dct1	12 kV-Disconnects	31	5,000					155,000	1				31
		PT1	12 kV-PT	5	3,000					15,000	1				5
	69 kV	Brk2	69 kV-Breakers	12	100,000				1,200,000		23			276	
		Dct2	69 kV-Disconnects	22	8,000				176,000		1			22	
		GDct1	69 kV-Grnd Disconnects	6	12,000				72,000		1			6	
		MODct1	69 kV-MODisconnects	16	12,000				192,000		1			16	
		PT2	69 kV-PT	2	5,000				10,000		2			4	
						-	-	-	1,650,000	9,712,000		-		324	966
						0%	0%	0%	15%	85%		0%		25%	75%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Scotland (5) - 1505	4 kV	Trf1	4 kV-66/4kV Power Transformer 9.375 MVA	3	1,000,000					3,000,000	20				60
		Brk1	4 kV-Breakers	26	100,000					2,600,000	23				598
		Dct1	4 kV-Disconnects	44	5,000					220,000	1				44
		PT1	4 kV-PTs	3	3,000					9,000	1				3
		Rctr1	4 kV-Reactors 9.375 MVA	2	1,000,000					2,000,000	20				40
		Reg1	4 kV-Regulators	4	12,000					48,000	2.5				10
	69 kV	Trf2	69 kV-115/69 kV Power Transformer - 40 MVA	2	2,500,000				5,000,000		20			40	
		Trf2	69 kV-115/69 kV Power Transformer - 80 MVA	1	2,500,000				2,500,000		20			20	
		Trf2	69 kV-138/69 kV Power Transformer - 24 MVA	4	2,500,000				10,000,000		20			80	
		Brk2	69 kV-Breakers	20	100,000				2,000,000		23			460	
		Cap	69 kV-Capacitor 28.8 MVA	1	345,600				345,600		8			8	
		Dct2	69 kV-Disconnects	45	8,000				360,000		1			45	
		GDct1	69 kV-Grnd Disconnects	9	12,000				108,000		1			9	
		GBnk2	69 kV-Ground Bank	1	500,000				500,000		7			7	
		PT2	69 kV-PT	5	5,000				25,000		2			10	
	115 kV	MODct2	115 kV-MODisconnects	2	15,000			30,000			1			2	
	138 kV	Brk3	138 kV-Breakers	3	128,000			384,000			20		60		
		Dct3	138 kV-Disconnects	8	9,700			77,600			1		8		
		GDct2	138 kV-Grnd Disconnects	6	15,000			90,000			1		6		
		MODct2	138 kV-MODisconnects	8	15,000			120,000			1		8		
		PT3	138 kV-PT	4	9,000			36,000			2		8		
						-	-	737,600	20,838,600	7,877,000		-	90	681	755
						0%	0%	3%	71%	27%		0.0%	5.9%	44.6%	49.5%
Sherbrook (14) - 1514	4 kV	Trf1	4 kV-66/4kV Power Transformer 10 MVA	2	1,000,000					2,000,000	20				40
		Brk1	4 kV-Breakers	19	100,000					1,900,000	23				437
		Dct1	4 kV-Disconnects	3	5,000					15,000	1				3
		PT1	4 kV-PTs	2	3,000					6,000	1				2
		Rctr1	4 kV-Reactor 10 MVA	1	1,000,000					1,000,000	20				20
	12 kV	Trf1	12 kV-69/12kV Power Transformer - 15 MVA	3	1,000,000					3,000,000	20				60
		Brk1	12 kV-Breakers	19	100,000					1,900,000	23				437
		Dct1	12 kV-Disconnects	9	5,000					45,000	1				9
		PT1	12 kV-PT	3	3,000					9,000	1				3
	69 kV	Trf3	69 kV-115/69 kV Power Transformer - 125 MVA	1	4,000,000				4,000,000		55			55	
		Brk2	69 kV-Breakers	7	100,000				700,000		23			161	
		Cap	69 kV-Capacitor 28.8 MVA	1	345,600				345,600		8			8	
		Dct2	69 kV-Disconnects	14	8,000				112,000		1			14	
		GDct1	69 kV-Grnd Disconnects	3	12,000				36,000		1			3	
		MODct1	69 kV-MODisconnects	9	12,000				108,000		1			9	
		PT2	69 kV-PT	3	5,000				15,000		2			6	
	115 kV	GDct2	115 kV-Grnd Disconnects	1	15,000			15,000			1		1		
		MODct2	115 kV-MODisconnects	1	15,000			15,000			1		1		
						-	-	30,000	5,316,600	9,875,000		-	2	256	1,011
						0%	0%	0%	35%	65%		0%	0%	20%	80%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
York (2) - 1502	12 kV	Trf1	12 kV-66/12kV Power Transformer - 16.6 MVA	3	1,000,000					3,000,000	20				60
		Brk1	12 kV-Breakers	19	100,000					1,900,000	23				437
		Dct1	12 kV-Disconnects	13	5,000					65,000	1				13
		PT1	12 kV-PT	3	3,000					9,000	1				3
	66 kV	Brk2	66 kV-Breakers	2	100,000				200,000		23			46	
		Dct2	66 kV-Disconnects	4	8,000				32,000		1			4	
		GDct2	66 kV-Grnd Disconnects	3	15,000				45,000		1			3	
		MODct1	66 kV-MODisconnects	6	12,000				72,000		1			6	
						-	-	-	349,000	4,974,000		-		59	513
34616						0%	0%	0%	7%	93%		0%		10%	90%
Brandon-Fortier 2689	12 kv	Trf1	12 kV-115/12kV Power Transformer 15 MVA	2	1,000,000					2,000,000	20				40
		Brk1	12 kV-Breakers	3	100,000					300,000	23				69
		Dct1	12 kV-Disconnects	20	5,000					100,000	1				20
		PT1	12 kV-PT	2	3,000					6,000	1				2
		Rclr1	12 kV - Recloser	8	25,000					200,000	10				80
	33 kV	Trf2	33 kV-115/33 kV Power Transformer - 30 MVA	1	2,500,000				2,500,000		20			20	
		Brk1	33 kV-Breakers	1	100,000				100,000		23			23	
		Dct1	33 kV-Disconnects	3	5,000				15,000		1			3	
		PT1	33 kV-PT	1	3,000				3,000		1			1	
	115 kV	GDct2	115 kV-Grnd Disconnects	2	15,000			30,000			1		2		
		Brk3	115 kV - Breaker	1	128,000			128,000			20		20		
		PT3	115 kV - PT	2	9,000			18,000			2		4		
		Dct3	115 kV - Disconnects	5	9,700			48,500			1		5		
		MODct2	115 kV-MODisconnects	3	15,000			45,000			1		3		
						-	-	269,500	2,618,000	2,606,000		-	34	47	211
						0%	0%	5%	48%	47%		0%	12%	16%	72%

Sum of Number of Components						Extended Cost						Extended Hours			
Station Name	Voltage	Item ID	Component & Voltage	Total	Unit Cost	Tran Cost	Ancillary Cost	Non Eligible Tran Cost	ST Cost	Dist Cost	Maintenance Hours	Tran Cost	Non Eligible Tran Cost	ST Cost	Ddst Cost
Dunlop - 2691	12 kv	Trf1	12 kV-66/12kV Power Transformer 1.5 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV-Disconnects	3	5,000					15,000	1				3
		Rclr1	12 kV - Recloser	1	25,000					25,000	10				10
	66 kV	Trf1	66 kV-230/66 kV Power Transformer - 10 MVA	1	1,000,000				1,000,000		20			20	
		Trf1	66 kV-230/4 kV Power Transformer - 10 MVA	1	1,000,000				1,000,000		20			20	
		Trf1	66 kV-4/66 kV Power Transformer - 2 MVA	1	1,000,000				1,000,000		20			20	
		Brk2	66 kV-Breakers	1	100,000				100,000		23			23	
		Dct2	66 kV-Disconnects	5	8,000				40,000		1			5	
		PT2	66 kV-PT	2	5,000				10,000		2			4	
	230 kV	GDct3	230 kV-Grnd Disconnects	1	18,000			18,000			1		1		
		Brk4	230 kV - Breaker	1	200,000			200,000			27		27		
		PT4	230 kV - PT	1	15,000			15,000			4		4		
		Dct4	230 kV - Disconnects	1	12,000			12,000			1		1		
		MODct3	230 kV-MODisconnects	1	18,000			18,000			1		1		
						-	-	263,000	3,150,000	1,040,000		-	34	92	33
						0%	0%	6%	71%	23%		0%	21%	58%	21%

						Extended Cost						Extended Hours			
Sum of Number of Components					Unit	Tran	Ancillary	Non Eligible Tran	ST	Dist	Maintenance	Tran	Non Eligible Tran	ST	Ddst
Station Name	Voltage	Item ID	Component & Voltage	Total	Cost	Cost	Cost	Cost	Cost	Cost	Hours	Cost	Cost	Cost	Cost
Poplarfield Station	12 kv	Trf1	12 kV-66/12kV Power Transformer 3 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV-Disconnects	1	5,000					5,000	1				1
		Rclr1	12 kV - Recloser	4	25,000					100,000	10				40
	33 kV	Trf1	33 kv - 66/33kv Power Transformer 7.5 MVA	1	1,000,000				1,000,000		20			20	
		Dct1	33 kv - Disconnects	7	5,000				35,000		1			7	
		PT1	33 kv - PT	1	3,000				3,000		1			1	
	66 kV	Trf1	66 kV-230/66 kV Power Transformer - 10 MVA	1	1,000,000				1,000,000		20			20	
		Brk2	66 kV-Breakers	4	100,000				400,000		23			92	
		Dct2	66 kV-Disconnects	15	8,000				120,000		1			15	
		PT2	66 kV-PT	1	5,000				5,000		2			2	
						-	-	-	2,563,000	1,105,000		-		157	61
						0%	0%	0%	70%	30%		0%		72%	28%
Pine Falls - 2686	12	Trf1	12 kV - 115/12kV Power Transformer - 5 MVA	2	1,000,000					2,000,000	20				40
		Trf1	12 kV - 115/12kV Power Transformer - 10 MVA	1	1,000,000					1,000,000	20				20
		Dct1	12 kV - Disconnects	17	5,000					85,000	1				17
		Rclr1	12 kV - Reclosers	4	25,000					100,000	10				40
	66	Trf1	66 kV - 115/66 kV Power Transformer - 15 MVA	2	1,000,000				2,000,000		20			40	
		Brk2	66 kV - Breakers	3	100,000				300,000		23			69	
		Dct2	66 kV - Disconnects	10	8,000				80,000		1			10	
		GBnk2	66 kV - Ground Bank	2	500,000				1,000,000		7			14	
		PT2	66 kV - PT	2	5,000				10,000		2			4	
	115	Dct3	115 kV - Disconnects	1	9,700			9,700			1		1		
		GDct2	115 kV - Grnd Disconnects	6	15,000			90,000			1		6		
		MODct2	115 kV - MODisconnects	8	15,000			120,000			1		8		
		PT3	115 kV - PT	3	9,000			27,000			2		6		
						-	-	246,700	3,390,000	3,185,000		-	21	137	117
						0%	0%	4%	50%	47%		0%	8%	50%	43%

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Schedules C8, C10 and E1 Average Rate Base Finance & Reserve Tab Base Alloc Data Tab
Topic:	Functionalization		
Subtopic:	Assets and Investments		
Issue:	Assignment to Functions – Buildings, Communication and General Equipment		

PREAMBLE TO IR (IF ANY):

The PCOSS14-Amended model uses the following Operating costs in the allocation of Buildings, Communications and General Equipment asset costs to functions:

OPERATING COSTS			
	GENERATION (excl Water Rentals, Fuel & Power Purchases)		212,211
	TRANSMISSION		75,616
	SUBTRANSMISSION		22,838
	DISTRIBUTION PLANT		82,595
	DISTRIBUTION SERVICES		
C10	- General Services		38,661
C13	- Marketing R&D		690
C14	- Electrical Inspection		3,092
C15	- Meter Reading		10,467
	Total Dist Service before Cust Accting		52,909
C11	- Customer Accting - Billing		24,147
C12	- Customer Accting - Collections		15,873
	Total Distribution Services		92,929
	STREET LIGHT DIRECTS		7,850
	Total Operating (excludes Diesel)		494,039

QUESTION:

a) Please reconcile the Transmission Operating costs reported here ($75,616 k) with the total Transmission Operating costs set out in Schedule E1 ($55,171, k)

b) Please reconcile the Generation Operating costs shown here ($212,211 k) with the total Generation Operating cost set out in Schedule E1 ($521,458 k).

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

a) The Operating costs used to functionalize Buildings, Communications and General Equipment rate base in PCOSS14-Amended were the same as those used in PCOSS14 and were not updated to reflect the change in functionalization of the Dorsey Converter Station.

An updated version of the operating costs reflecting PCOSS14-Amended methodology is shown below.

OPERATING COSTS		
	GENERATION (excl Water Rentals, Fuel & Power Purchases)	232,656
	TRANSMISSION	55,171
	SUBTRANSMISSION	22,838
	DISTRIBUTION PLANT	82,595
	DISTRIBUTION SERVICES	
C10	- General Services	38,661
C13	- Marketing R&D	690
C14	- Electrical Inspection	3,092
C15	- Meter Reading	10,467
	Total Dist Service before Cust Accting	52,909
C11	- Customer Accting - Billing	24,147
C12	- Customer Accting - Collections	15,873
	Total Distribution Services	92,929
	STREET LIGHT DIRECTS	7,850
	Total Operating (excludes Diesel)	494,039

Use of the revised operating costs does result in a material change to the relative amounts of Buildings, Communication and Generation Equipment rate base that is functionalized as Generation versus Transmission. However, the overall change to the functionalization of Interest expense is not significant and does not result in any changes to class RCC ratios after rounding (RCC results in PCOSS are rounded to 1/10th of one percent).

b) Water Rentals, Fuel and Power Purchases are significant and readily identifiable costs, and are excluded from the Generation Operating costs used to functionalize Buildings, Communications and General Equipment rate base to make the allocator more consistent with the labour dollars used to functionalize the operating and depreciation costs for these assets in SAP.

Section:	Appendix 3.1 PCOSS14-Amended (filed with the COSS model)	**Page No.:**	Schedule C8, C10 and C12 Schedules C8, C10 and C12 Average Rate Base Finance & Reserve Tab Base Alloc Data Tab
Topic:	Functionalization		
Subtopic:	Assets and Investments		
Issue:	Assignment to Functions – Buildings, Communication and General Equipment		

PREAMBLE TO IR (IF ANY):

The PCOSS14-Amended model uses the following Operating costs in the allocation of Buildings, Communications and General Equipment asset costs to functions:

OPERATING COSTS			
	GENERATION (excl Water Rentals, Fuel & Power Purchases)		212,211
	TRANSMISSION		75,616
	SUBTRANSMISSION		22,838
	DISTRIBUTION PLANT		82,595
	DISTRIBUTION SERVICES		
C10	- General Services		38,661
C13	- Marketing R&D		690
C14	- Electrical Inspection		3,092
C15	- Meter Reading		10,467
	Total Dist Service before Cust Accting		52,909
C11	- Customer Accting - Billing		24,147
C12	- Customer Accting - Collections		15,873
	Total Distribution Services		92,929
	STREET LIGHT DIRECTS		7,850
	Total Operating (excludes Diesel)		494,039

QUESTION:

a) Please provide the equivalent to the Table set out in the Preamble based on PCOSS14.

b) It is noted that the values for Building assets, Communications assets and General Equipment assets allocated to Generation are the same for both PCOSS14 and PCOSS14-Amended (Schedule C10) even though there has been a material shift in Operating costs between Generation and Transmission- Tariffable (Schedule C12). Please explain why this is the case.

c) In the case of Communications assets in PCOSS14-Amended, what is the basis for the $7.86 M that is separately identified and allocated to Generation, Sub- Transmission and Ancillary Services? Also, what is the basis for the 36/36/28 split between the three functions?

d) In PCOSS14-Amended, what is the basis for the 87.5%/12.5% split of Buildings, Communications and General Equipment allocated to Transmission between Tariffable and Non-Tariffable?

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

a) The table depicted in the preamble is consistent with the table used in PCOSS14. Please see Manitoba Hydro's response to COALITION/MH 1-35a for further discussion.

b) Please see Manitoba Hydro's response to COALITION/MH I-35a.

c) Please see Manitoba Hydro's response to COALITION/MH I-32.

d) The relative proportions of Tariffable to Non-Tariffable Transmission in the opening Gross investment at March 31, 2012 were applied to accumulated depreciation, forecast additions and forecast depreciation resulting in the 87.5/12.5% split of Buildings, Communications, and General Equipment.

Section:	Appendix 3.1 MISO Transmission Owners Agreement MISO Business Practice Manual BPM-028 – Transmission Determination Process	Page No.:	Page 11 Schedule C8
Topic:	Functionalization		
Subtopic:	Non-Tariffable Transmission.		
Issue:	MISO Requirements		

PREAMBLE TO IR (IF ANY):

It is noted that the MISO Transmission Owners Agreement (TOA) requires MISO to make a transmission determination for a prospective or existing Transmission Owner where the Transmission Owner is not subject to regulation by a regulatory authority (i.e., FERC or a State Commission). (TOA Appendix C, Part II, Section C, Paragraph 2)

The referenced MISO Business Practice Manual can be found at

https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

QUESTION:

a) How was the determination made that radial taps were non-tariffable?

b) If the determination was made by MISO, was it based on the above referenced (or a similar) business practice document? If not the one referenced, please provide the relevant MISO business practice document.

c) If the determination was not made by MISO, how and by whom was it made?

d) If the determination was not made by MISO, in Manitoba Hydro's view do Radial Taps meet the definition of transmission as set out in the applicable MISO Business Practice Manual? Please explain why.

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

Response to parts a) to d):

The Transmission Owners Agreement and its corresponding MISO Business Practice Manual reference does not apply to Manitoba Hydro as a transmission owner. Manitoba Hydro's relationship with MISO is governed by a Coordination Agreement that does not give MISO authority to determine the classification of Manitoba Hydro facilities for purposes of the OATT.

Pursuant to the Coordination Agreement, Manitoba Hydro relies on the 7-factor test and used and useful criteria for purposes of determining tariffable transmission facilities. Both these tests are established by the U.S. Federal Energy Regulatory Commission. Based on the 7-factor test, Manitoba Hydro views that radial taps are not tariffable and both the AC facilities at Dorsey and Riel are tariffable. Based on the used and useful criteria, Manitoba Hydro's view is that its Bipole facilities including Bipole III are appropriately defined as generation-related and not eligible for inclusion in its transmission tariff as these facilities are not considered to be available to all transmission customers of the Manitoba Hydro tariff. The DC facilities at Dorsey and upcoming Riel, are also reasonably deemed as generation-related, and ineligible for inclusion in the transmission tariff on the basis that these facilities are not used and useful by all transmission customers of the Manitoba Hydro tariff.

For purposes of the OATT, as long as Manitoba Hydro is compliant with the 7-factor test, as required by the Coordination Agreement, Manitoba Hydro can determine the functionalization of assets.

Manitoba Hydro also supports use of the 7-factor (or similar) test to demarcate grid transmission from radial transmission and distribution in the COS for domestic classes, both because of its inherent reasonableness and because there is value in maintaining consistent treatment of assets as between the open market for wholesale transmission and for cost allocation to domestic customers.

Section:	Appendix 3.1	**Page No.:**	Page 11 Schedule C8
Topic:	Functionalization		
Subtopic:	Non-Tariffable Transmission.		
Issue:	Radial Lines		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Schedule C8 reports $209.2 M of Transmission Assets in Rate Base that are assigned to the Non-Tariffable Transmission function. Are these costs all related to dedicated radial taps serving GSL>100kV customers?

b) If not, what portion of the $209.2 M is associated with radial taps serving GSL>100 kV customers and what assets account for the balance of the costs? Also, how where these other costs treated in PCOSS13?

c) Do all of the transmission lines (taps) in this function deliver power to customer owned transformer stations?

d) The same schedule shows $111.99 M of Substation Assets in Rate Base that are assigned to the Non-Tariffable Transmission function. Please describe the assets these costs are associated with and whether or not they are directly associated with the radial tap lines.

e) Appendix 3.1 indicates (page 11) the proposed treatment of radial taps as opposed to direct assignment has an inconsequential impact on revenue cost coverage ratios. What is the impact?

f) Does Manitoba Hydro have 66 kV and 33 kV radial taps that directly serve GSL 30-100 kV customers (or any other customers)? If yes, are the associated costs included in the

Subtransmission function?

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

As part of the review undertaken by Manitoba Hydro to reflect the advice of CA that dedicated radial taps serving GSL >100 kV not be include in the Sub-transmission function, Manitoba Hydro also identified other transmission assets (non-tarrifable) in the sub-transmission function. The dedicated radial taps represent only two of the assets included in the Non-Tariffable Transmission function. The 2014 net book value for the two identified taps was $2.9 million dollars net of customer contributions. The impacts as a result of the change are identified in PUB MFR 12, Schedule B7.

The table below lists all other assets identified and now included in the Non Tariffable Transmission function in PCOSS14-Amended and indicates how these assets were functionalized in PCOSS13. The transmission line taps included in this function deliver power to Manitoba Hydro owned substations.

Designation	Transmission Line Description	PCOSS13 Function
230 kV Taps	230 kV AC T/L Taps	Subtransmission
B78-S	St Leon - Bison Wind 230 kV AC T/L	Subtransmission
J89L	St. Joseph - Letellier 230kV AC T/L	Subtransmission
W1,W2,W3	Wusk GS-Wusk Sw Stn 230kv Collector Line	Transmission
W73H W74H	Wuskwatim-Herblet Lake 230kv AC T/L	Transmission
W76B	Wuskwatim-Birchtree 230 kV AC T/L	Transmission
138 kV Taps	138 kV AC T/L Taps	Subtransmission
BK-9, TW-40	Thompson-Mystery Lake 138 kV AC T/L	Transmission
KH-38 to GW62	Kelsey-Wasagamach 138 kV AC T/L	Subtransmission
KN-36	Kelsey-Radisson - Limestone 138 kV AC T/ L	Subtransmission
KS-37	Kelsey-Split Lake 138 kV AC T/L	Subtransmission
KT-1, KT-2	Kelsey-Thompson 138 kV AC T/L	Transmission
RC-60	Radisson-Churchill 138 kV AC T/L	Subtransmission
RN-46	Ruttan-Leaf Rapids138 kV AC T/L	Subtransmission
WB-45	Mystery Lake-Burntwood 138 kV AC T/L	Subtransmission
WL-43	Mystery Lake-Laurie R. 138 kV AC T/L	Subtransmission
115 kV Taps	115 kV AC T/L Taps	Subtransmission
GP-1	Great Falls-Pine Falls115 kV AC T/L	Transmission

GT-1	Great Falls-Transcona 115 kV AC T/L	Transmission
PA-1, PA-2	Pine Falls-Abitibi 115 kV AC T/L	Subtransmission
PR-2	Pine Falls-McArthur 115 kV AC T/L	Transmission
R1-R2	Slave Falls to Pointe Du Bois 115 kV AC T/L	Transmission
S1-S2	Slave Falls to Scotland 115 kV AC T/L	Transmission
P1-P4	Pointe Du Bois to Rover Str 66 kV AC SubT/L	Transmission

Please see Manitoba Hydro's response to COALITION/MH I-34c for a discussion of the process used to functionalize Substations.

Radial taps directly serving GSL 30-100kV customers continue to be included in the Subtransmission function.

Section:	Appendix 3.1 MFR 18	Page No.:	Page 11 Schedule C8 Pages 1-2
Topic:	Functionalization		
Subtopic:	Non-Tariffable Transmission.		
Issue:	Radial Lines		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) At the time the radial lines serving GSL>100 kV customers were built were they considered to be a service extension such that the customers were subject to Manitoba Hydro's service extension policy?

b) If so, were the customers required to make any capital contributions to the cost of the lines and did the contribution calculations consider the full cost of the line prior to applying any applicable allowances?

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

a) Confirmed.

b) Customers served at voltages greater than 100 kV are required to pay all costs associated with constructing the facilities from the customer's point of delivery to the point of connection with Manitoba Hydro's existing common integrated system. These radial lines are not subject to a revenue test and are not eligible for an allowance.

Section:	Submission Appendix 3.1	**Page No.:**	Page 9 Page 37 (Schedule C8)
Topic:	Functionalization		
Subtopic:	Northern Collector Circuits		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The chart set out on page 9 of the Submission indicates that the Northern Collector Circuits are considered to be part of the Generation function. However, in Schedule C8 there are no transmission assets (other than HVDC) that are functionalized to Generation. Please reconcile and indicate where in Schedule C8 the Northern Collector Circuits are reflected.

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

The Northern Collector A/C transmission lines are included in the Transmission - HVDC row in Schedules C1-C12.

Section:	Submission Appendix 4	**Page No.:**	Page 9 Page 8
Topic:	Functionalization		
Subtopic:	Bipole I & II		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the justification for Bipole I & II as would have been set out in the project's CPJ(s) at the time they were approved.

RATIONALE FOR QUESTION:

To understand the functionalization of assets.

RESPONSE:

Manitoba Hydro does not have CPJs related to the justification or construction of Bipoles I and II as the projects were a joint initiative by the Federal and Provincial Governments in the 1960s and 1970s. The lines were owned by the Federal Government until the early 1990s at which point ownership was transferred to Manitoba Hydro.

Section:	Submission Appendix 4 MISO Transmission Owners Agreement MISO Business Practice Manual BPM-028 – Transmission Determination Process	**Page No.:**	Page 9 Page 8
Topic:	Functionalization		
Subtopic:	Bipole I & II		
Issue:	Proposed Treatment as Generation		

PREAMBLE TO IR (IF ANY):

It is noted that the MISO Transmission Owners Agreement (TOA) requires MISO to make a transmission determination for a prospective or existing Transmission Owner where the Transmission Owner is not subject to regulation by a regulatory authority (i.e., FERC or a State Commission). (TOA Appendix C, Part II, Section C, Paragraph 2)

The referenced MISO Business Practice Manual can be found at

https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

QUESTION:

a) Has MISO ever made a determination as to whether or not Bipole I and II are to be considered as transmission and "tariffable"? If yes, what was the determination?

b) If not, in Manitoba Hydro's view, do Bipole I and II meet the definition of transmission as set out in the applicable MISO Business Practice Manual? Please explain why.

c) If MISO has determined that Bipole I & II are transmission and tariffable or if, in Manitoba Hydro's view, they meet MISO's definition of "transmission", please explain why Manitoba Hydro considers the facilities to be part of the Generation function.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Bipole I & II

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH I-37.

Section:	Submission Appendix 1 MISO Transmission Owners Agreement MISO Business Practice Manual BPM-028 – Transmission Determination Process	**Page No.:**	Page 9 Page 5
Topic:	Functionalization		
Subtopic:	Bipole III – Transmission Facilities		
Issue:	Proposed Future Treatment as Generation		

PREAMBLE TO IR (IF ANY):

It is noted that the MISO Transmission Owners Agreement (TOA) requires MISO to make a transmission determination for a prospective or existing Transmission Owner where the Transmission Owner is not subject to regulation by a regulatory authority (i.e., FERC or a State Commission). (TOA Appendix C, Part II, Section C, Paragraph 2)

The referenced MISO Business Practice Manual can be found at

https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

QUESTION:

a) In Manitoba Hydro's view, would Bipole III meet the definition of transmission as set out in the applicable MISO Business Practice Manual? Please explain why.

b) If, in Manitoba Hydro's view, Bipole III meets MISO's definition of "transmission" please explain why Manitoba Hydro plans to treat the facilities as part of the Generation function.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Bipole III

RESPONSE:

Please see Manitoba Hydro’s response to COALITION/MH I-37.

Section:	Submission Appendix 1	Page No.:	Page 9 Page 5
Topic:	Functionalization		
Subtopic:	Bipole III – Transmission Facilities		
Issue:	Proposed Future Treatment as Generation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the most current CPJ for the Bipole III project that includes the justification for the project.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Bipole III

RESPONSE:

Please find attached the current CPJ Addendums for all portions of the Bipole III project.

The current CPJ Addendum for the Transmission Line can be found as Attachment 1 to this response.

The current CPJ Addendums for the Converter Stations and Collector Lines were filed during the 2014/15 & 2015/16 GRA and can be found as Attachments 2 and 3 to this response.

The justification for the different portions of the BiPole III project are contained within the Addendums.

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AD FOR

Bipole III Project
TRANSMISSION LINE
Addendum Number 07a

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/01

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,259,915,000
REVISED BUDGET $: (Total Net Cost)	$1,655,371,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $395 million for the Transmission Line components of the Bipole III Project, to a revised total of $1,655 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:
- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk (Keewatinoow) Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).

Changes to scope include: revised line length of final approved route, issued Licence & Conditions, revised landowner compensation strategy and policy, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based on a preferred routing of the line prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. Also since the last estimate, the project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line and change to project in-service of July 2018.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for market uncertainty risk for transmission line construction work.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $363 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Changes to the finalized route (increased length, additional towers and increased right-of-way width)
- Updated land acquisition costs
- Recommended contingency of $110M (increase of $61M) to address remaining uncertainty. See

Background (This section is be filled out only if there is information relevant to the recommendation).

Risk Analysis section.

Reserves:
A Management Reserve has been established to address significant risks related to bidding market and pricing uncertainty for Transmission Line construction work (increase of $100M). See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project is $395M (31%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Additionally, this portion of the Bipole III Project includes a recommended Management Reserve of $100M associated with bidding market and pricing uncertainty for Transmission Line construction work. This remains the greatest area of uncertainty for Bipole III and the potential cost variation associated with this risk is best addressed through the inclusion of Management Reserve funds.

An additional, significant area of uncertainty is the potential impacts to schedule due to further delays in acquisition of private lands. A Management Reserve for this risk has not been recommended as part of the project budget. However, there will be cost impacts to the project should the risk occur.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 24,613	$ 24,613	$ -
2010/11	$ 16,118	$ 19,002	$ 2,884
2011/12	$ 24,830	$ 18,350	$ (6,480)
2012/13	$ 59,866	$ 25,091	$ (34,775)
2013/14	$ 162,043	$ 54,276	$ (107,767)
2014/15	$ 298,935	$ 203,458	$ (95,477)
2015/16	$ 318,454	$ 360,455	$ 42,001
2016/17	$ 234,575	$ 381,047	$ 146,472
2017/18	$ 120,055	$ 493,821	$ 373,766
2018/19	$ 426	$ 75,257	$ 74,831
Total	$ 1,259,915	$ 1,655,371	$ 395,456

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A
FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 07b

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,828,532,000
REVISED BUDGET $: (Total Net Cost)	$2,675,083,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).
Increase the budget by $ 846.5 million for the Converter Station components of the Bipole Project, to a revised total of $2,675 and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:
- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.

Changes to scope include: Selection of LCC HVdc technology requiring the inclusion of Synchronous Condensers, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based largely on historical and budgetary pricing from vendors as well as an assumption of VSC technology for the HVdc Converter and therefore no requirement for synchronous condensers.

The revised estimate is based on LCC HVdc technology as this was the technology bid by all vendors and incorporates the bid pricing received. The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>
Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $649 million to the P50 Estimate as a result of the following:
- Incorporation of contract costs for the Keewatinohk 230kV AC Switchyard, Keewatinohk Site Development, Keewatinohk Camp and Keewatinohk Camp Services
- Incorporation of bid price for the Keewatinohk and Riel HVdc Converter Equipment contract
- Inclusion of Synchronous Condensers in the scope of work as a result of LCC technology for the HVdc equipment
- Incorporation of allocated portion of actual costs for Riel Sectionalization project
- Incorporation of updated costs for the Riel 230kV AC Switchyard Expansion

Background (This section is be filled out only if there is information relevant to the recommendation).

- Recommended contingency of $119.6M (decrease of $16M) to address remaining uncertainty.

Reserves:
No Management Reserve for the Converter Stations component of the project is recommended to include in the estimate at this time.

In-Service Costs:
The overall increase to the in-service cost of the project is $846.5 (46%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 30,423	$ 30,423	$ -
2010/11	$ 46,255	$ 28,069	$ (18,186)
2011/12	$ 59,696	$ 36,417	$ (23,279)
2012/13	$ 148,883	$ 79,718	$ (69,165)
2013/14	$ 300,258	$ 144,153	$ (156,105)
2014/15	$ 290,185	$ 221,051	$ (69,134)
2015/16	$ 294,281	$ 580,792	$ 286,511
2016/17	$ 308,460	$ 828,733	$ 520,273
2017/18	$ 347,692	$ 507,689	$ 159,997
2018/19	$ 2,399	$ 195,085	$ 192,686
2019/20	$ -	$ 18,432	$ 18,432
2020/21	$ -	$ 4,520	$ 4,520
Total	$ 1,828,532	$ 2,675,083	$ 846,551

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A
FOR

Bipole III Project
COLLECTOR LINES
Addendum Number 07c

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: Bruce Barrett 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$191,438,000
REVISED BUDGET $: (Total Net Cost)	$260,150,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P:20790, P:21201, P:23816

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ Customer Service
- ☐ System Supply
- ☐ Efficiency
- ☒ System Reliability
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $68.7 million for the Collector Lines components of the Bipole III Project, to a revised total of $260.2 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:
- Design and construction of three permanent and two temporary 230 KV collector lines for the Keewatinohk (Keewatinoow) Converter Station.
- Construction power substation, 138 KV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station.
- Design and construction of the Riel and Keewatinohk electrode lines.
- Sectionalization of 230 KV transmission line R49R at Riel and associated modifications at Ridgeway and Rosser stations.
- Property acquisition and/or easements for the above components.
- Design and construction of a new bay and modifications at existing Long Spruce 230 KV AC switchyard for the new collector line to Keewatinohk Converter Station.
- Design and construction of a new bay and modifications at existing Henday 230 KV AC switchyard for the four new collector lines to Keewatinoow Converter Station.
- Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Changes to scope include: the issued Licence & Conditions, double circuit requirement for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts, inclusion of Long Spruce and Henday 230 KV station expansions/modifications, inclusion of breaker replacements, and revised schedule and project in-service date to July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2009/10, based on conceptual scope of collector line components, prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, increased scope (new items in this component), as well as up-to-date market information. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>
Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. In addition, new items were included in the current scope for this component.

Background (This section is be filled out only if there is information relevant to the recommendation).
This resulted in an increase of $83 million to the P50 Estimate as a result of the following: • Incorporation of Environment Act Licence conditions and monitoring requirements • Change to include a double circuit requirement for the Keewatinoow to Long Spruce AC collector line • Incorporation of increased reliability design for both electrode lines • Change to assume Clearing, 230kV AC transmission line construction and Construction Power contracts as Direct Negotiated Contracts (DNCs) • Inclusion of new items – Long Spruce and Henday 230 KV station expansions/modifications and breaker replacements projects • Recommended contingency of $18M (increase of $800K) for this component, to address remaining uncertainty. See Risk Analysis section. <u>Reserves:</u> No Management Reserve for the Collector Lines components is recommended to include in the estimate at this time. See Risk Analysis section. <u>In-Service Costs:</u> The overall increase to the in-service cost of the project for this component is $68 M (36%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date and increase in the recommended contingency. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).
A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV** Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 0	$ 0	$ -
2010/11	$ 2,121	$ 386	$ (1,735)
2011/12	$ 19,917	$ 2,075	$ (17,842)
2012/13	$ 52,709	$ 4,394	$ (48,315)
2013/14	$ 30,141	$ 26,265	$ (3,876)
2014/15	$ 30,927	$ 58,432	$ 27,505
2015/16	$ 34,255	$ 75,516	$ 41,261
2016/17	$ 13,549	$ 51,722	$ 38,173
2017/18	$ 7,819	$ 36,708	$ 28,889
2018/19	$ -	$ 4,653	$ 4,653
Total	$ 191,438	$ 260,150	$ 68,711

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

Section:	Submission Appendix 3 Appendix 3.1	**Page No.:**	Page 9 Page 3 Page 25
Topic:	Functionalization		
Subtopic:	Dorsey		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

In PCOSS14, Dorsey is functionalized as Transmission. For PCOSS14-Amended Manitoba Hydro states that "the Dorsey Converter facilities are functionalized 100% as Generation".

QUESTION:

a) Please describe what other facilities, besides the converter, are located at the Dorsey Station.

b) What is the relative cost (i.e., gross investment) of the converter facilities at Dorsey as compared to the cost of the station overall?

c) Please clarify whether for PCOSS14-Amended all of the costs associated with Dorsey are treated as Generation or just the costs of the converter facilities.

d) If all of the costs are treated as Generation, please explain why this is appropriate.

e) As compared to the results set out in Appendix 3, what would be the impact on the customer class R/C ratios if the costs of Dorsey were all functionalized as Transmission?

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Dorsey

RESPONSE:

a) Dorsey converter station consists of several facilities. The 500 kV DC switchyard for switching operation of Bipole I and II dc lines, the dc converter buildings housing the dc to ac conversion devices, converter transformers, ac filters and synchronous condensers are functionalized 100% as generation as per the PCOSS14-Amended, as they are essential to the operation of our HVDC system.

There are both the 230 kV ac switchyard and the 500 kV ac switchyard for switching operations of the ac lines and associated apparatus at Dorsey, which are considered as 100% of Transmission.

b) Gross Investment in PCOSS14-Amended is as follows:

	Gross Investment	
Dorsey Converter Station	681,531,304	84%
Dorsey Stn - 230 Kv AC Switchyard	74,694,382	9%
Dorsey Stn. - 500 kV AC Switchyard	54,719,889	7%
Total Dorsey Station	**810,945,576**	

c) As per page 6 of Manitoba Hydro's Response to Supplemental Cost of Service Recommendations, dated December 4, 2015 (Appendix 1), PCOSS14-Amended functionalizes just the converter facilities at Dorsey as Generation.

d) Please see Manitoba Hydro's response to part c).

e) The summary schedules reflecting the functionalization of the Dorsey Converter Station as Transmission can be found below.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014
Revenue Cost Coverage Analysis
Model of Coalition-MH 1-45e
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Cost less NER	Change Cost less NER	Change in RCC	Change in NER
Residential	631,407	588,630	39,801	628,431	99.5%	591,606	1,571.6	-0.3%	
General Service - Small Non Demand	132,873	135,035	8,142	143,177	107.8%	124,731	282.9	-0.2%	
General Service - Small Demand	138,421	136,080	8,469	144,549	104.4%	129,952	99.7	-0.1%	
General Service - Medium	200,459	186,797	12,360	199,157	99.4%	188,099	146.4	0.0%	
General Service - Large 0 - 30kV	99,791	84,956	6,138	91,094	91.3%	93,653	4.8	0.0%	
General Service - Large 30-100kV*	61,260	57,808	3,831	61,639	100.6%	57,429	(376.4)	0.6%	
General Service - Large >100kV*	202,920	189,258	12,565	201,823	99.5%	190,355	(1,668.5)	0.9%	
*Includes Curtailment Customers									
SEP	968	826	-	826	85.4%	968	-	0.0%	
Area & Roadway Lighting	21,946	21,630	421	22,051	100.5%	21,525	(52.7)	0.3%	
Total General Consumers	1,490,045	1,401,019	91,728	1,492,747	100.2%	1,398,316	7.7	0.0%	
Diesel	9,948	6,612	634	7,246	72.8%	9,314	(7.7)	0.0%	
Export	252,871	345,233	(92,362)	252,871	100.0%				1,198.8
Total System	1,752,864	1,752,864	-	1,752,864	100.0%				

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Customer, Demand, Energy Cost Analysis
Model of Coalition/MH-I-45e
SUMMARY

	CUSTOMER			DEMAND				ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	120,683	486,987	20.65	197,373	0%	n/a	n/a	273,550	7,404,453	6.36	**
GS Small - Non Demand	24,035	53,778	37.24	37,737	0%	n/a	n/a	62,959	1,605,511	6.27	**
GS Small - Demand	8,166	12,492	54.48	43,881	38%	2,390	6.96	77,905	2,047,715	5.14	
General Service - Medium	7,142	1,974	301.49	63,129	87%	7,302	7.56	117,828	3,174,662	3.96	
General Service - Large <30kV	3,593	288	n/a	27,886	100%	4,042	7.79 *	62,175	1,702,481	3.65	
General Service - Large 30-100kV	2,483	40	n/a	11,334	100%	2,894	4.77 *	43,611	1,327,210	3.29	
General Service - Large >100kV	2,294	16	n/a	27,782	100%	8,409	3.58 *	160,279	4,903,742	3.27	
SEP	326	29	935.95	132	0%	n/a	n/a	509	26,500	2.42	**
Area & Roadway Lighting	16,570	155,024	8.91	2,233	0%	n/a	n/a	2,722	100,487	4.93	**
Total General Consumers	185,291	710,628		411,487		25,038		801,538	22,292,761		
Diesel	220	755	24.26	330	0%	n/a	n/a	8,765	13,754	66.12	**
Export	n/a	n/a	n/a	29,681	0%	n/a	n/a	223,190	9,013,000	2.81	***
Total System	185,511	711,383		441,498		25,038		1,033,493	31,319,515		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Functional Breakdown
Model of Coalition/MH-I-45e
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	591,606	272,268	46.0%	65,272	11.0%	30,982	5.2%	66,620	11.3%	156,464	26.4%
General Service - Small Non Demand	124,731	62,681	50.3%	13,938	11.2%	5,592	4.5%	16,930	13.6%	25,589	20.5%
General Service - Small Demand	129,952	77,557	59.7%	16,492	12.7%	6,443	5.0%	4,045	3.1%	25,415	19.6%
General Service - Medium	188,099	117,293	62.4%	25,315	13.5%	8,908	4.7%	6,157	3.3%	30,426	16.2%
General Service - Large <30kV	93,653	61,893	66.1%	13,083	14.0%	4,453	4.8%	3,377	3.6%	10,846	11.6%
General Service - Large 30-100kV	57,429	43,407	75.6%	8,137	14.2%	3,401	5.9%	2,417	4.2%	67	0.1%
General Service - Large >100kV	190,355	159,537	83.8%	28,524	15.0%	0	0.0%	2,266	1.2%	27	0.0%
SEP	968	509	52.6%	132	13.7%	0	0.0%	309	31.9%	17	1.7%
Area & Roadway Lighting	21,525	2,837	13.2%	449	2.1%	442	2.1%	537	2.5%	17,260	80.2%
Total General Consumers	1,398,316	797,983	57.1%	171,343	12.3%	60,220	4.3%	102,659	7.3%	266,110	19.0%
Diesel	9,314	8,765	94.1%	0	0.0%	0	0.0%	0	0.0%	550	5.9%
Export	252,871	222,440	88.0%	30,431	12.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,660,502	1,029,188	62.0%	201,774	12.2%	60,220	3.6%	102,659	6.2%	266,660	16.1%

Section:	Submission Appendix 3 Appendix 3.1 MISO Transmission Owners Agreement MISO Business Practice Manual BPM-028 – Transmission Determination Process	**Page No.:**	Page 9 Page 3 Page 25
Topic:	Functionalization		
Subtopic:	Dorsey		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

It is noted that the MISO Transmission Owners Agreement (TOA) requires MISO to make a transmission determination for a prospective or existing Transmission Owner where the Transmission Owner is not subject to regulation by a regulatory authority (i.e., FERC or a State Commission). (TOA Appendix C, Part II, Section C, Paragraph 2)

The referenced MISO Business Practice Manual can be found at

https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

QUESTION:

a) Has MISO ever made a determination as to whether or not Dorsey is to be considered as transmission and "tariffable"? If yes, what was the determination?

b) If not, in Manitoba Hydro's view, does Dorsey meet the definition of transmission as set in the applicable MISO Business Practice Manual? Please explain why.

c) If MISO has determined that Dorsey is transmission and tariffable or if, in Manitoba Hydro's view, Dorsey meets MISO's definition of "transmission", please explain why Manitoba Hydro considers the facilities to be part of the Generation function.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Dorsey.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH I-37.

Section:	Submission Appendix 2	**Page No.:**	Page 3 Page 12, Footnote 7
Topic:	Functionalization		
Subtopic:	Riel		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

The Submission states that "it is also Manitoba Hydro's intention to functionalize the upcoming Riel Converter facilities on this basis (i.e., as generation)". Appendix 2 notes that the Riel Station is comprised of two separate projects – the Riel Reliability Project and the Bipole III Reliability Project.

QUESTION:

a) Please provide the most current CPJs for the Riel Reliability Project and the Riel Converter Station portion of the Bipole III project.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Riel.

RESPONSE:

Please see Attachment 1 for the current CPJ Addendum for the Riel 230/500Kv Station (Riel Reliability Project) which was approved in September 2015. Please see Manitoba Hydro's response to COALITION/MH I-44a for the CPJ Addendum related to the Riel Converter Station.

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1543.04

DATE: 2015 10 01
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Riel 230/500kV Station

Addendum Number 09

REVIEWED BY:
(Owning Dept Manager) David Swatek 2015/09/08

NOTED BY:
(if applicable)

Coordinating Division: 2015/09/08

Constructing Division:

2015.09.09

Financial: 2015/09/11

RECOMMENDED FOR IMPLEMENTATION:
Owning Div. Manager: 2015/09/08

Business Unit V.P.: 2015-09-10

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$329,937,000
REVISED BUDGET $: (Total Net Cost)	$319,918,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	Mult - 2014 10
REVISED ISD: (Indicate "Mult" if more than 1)	Mult - 2015 04
RISK MATRIX/ BUSINESS CASE TIER:	Mandatory (750 points)
INVESTMENT REASONS:	Operational Enhancement (60%) Capacity Enhancement (20%) New/Increased Gen. Delivery (20%)

OWNING DIVISION: Transmission Planning & Design

I.M. NODE NUMBER: 1.5.2.2.1.1

W.B.S. NUMBERS: P:04219, P:13064, P:18263, P:18277, P:18545, P:20959

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: D. Jacobson (Project Owner) 2015/08/28
L. Miller (Project Officer) 2015/08/2?

DATE PREPARED: 2015 07 28

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE * ☒ **YES** ☐ **NO**

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

08	2013 08 20	Increase budget by $62.4 million	D. Jacobson / J. Wheatley	Executive Committee (Minute #1453.03)
07	2008 07 10	Increase budget by $162 million and defer ISD to 2014 05	D. Jacobson / A. Poulin	Executive Committee (Minute #1236.04)
06	2006 06 06	Defer ISD from 2012 10 to 2014 03	M. Adamkowicz	Executive Committee (Minute #1148.05)
05	2005 06 29	Defer ISD from 2010 10 to 2012 10	K.L. Kent / J.B. Davies	Executive Committee (Minute #1085.07)

04	2004 06 14	Defer ISD from 2008 08 to 2010 10	K.L. Kent / J.B. Davies	Executive Committee (Minute #1039.03)
03	2003 11 12	Defer $698k from 2003/04 to 2004/05	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
02	2003 08 06	Reduce budget requirements for 2003/04 by $4,851k.	W.N. Zurba / C.A. Nieuwenburg	Executive Committee (Minute #993.03)
01	2002 07 17	Reduce budget requirements covering environmental licensing, as these costs are covered elsewhere.	C.A. Nieuwenburg	Executive Committee (Minute #943.04)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #899.04)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Riel 230/500kV Station

Recommendation (This section is required for all Addendums).

Decrease the budget by $10.0 million to a revised project total of $319.9 million, reflective of the project being placed fully in-service. The decrease is due primarily to the reduction to Contingency, elimination of forecast escalation, and lower capitalized interest.

Project Scope (This section is be filled out only if there is a change to the scope).

There is no change to the project scope. The 230kV assets were placed in service in May 2014 and the 500kV assets were placed in service in October 2014, both as planned per the previous CPJ Addendum.

All of the project work is nearly complete. There are $2.8 million of expenditures planned for 2015/16, to address outstanding contract work and project deficiencies. The details of the more significant work that remains are as follows:

a) Transmission Line & Civil Construction-Civil Contracts ($1.2 million)
Remaining costs pertains to the fire water system, the deep underground contract, final site grading, and security gate installation.

The firewater system is the largest component of the remaining work, at $0.7 million (plus $0.3 million in association with the Riel Converter Station under the Bipole III budget). These funds have been set aside for the supply and installation of water storage tanks, in place of the original plan to connect to the City of Winnipeg's Deacon's Reservoir. Approval by the City of Winnipeg had been granted in February 2010 and a Construction Agreement was signed in February 2012 for a permanent firewater connection to Deacon's Reservoir; however, in June of 2013 Manitoba Hydro received notification that the agreement was in jeopardy due the International Joint Commission's outlined use of water from Shoal Lake. Discussions with the City of Winnipeg have been ongoing since, but with no resolution forthcoming alternative means for supplying firewater are being developed.

b) Station Design-Contracts ($0.7 million)
Close-out of the Engineer & Procure contract, which includes ongoing contract administration, as-built drawings, deficiencies and warranties.

c) Deficiencies ($0.9 million)
Various other deficiencies as identified on the commissioning certificate, involving multiple areas of responsibility. These include:

- replacement of 12 fans on the 500kV auto transformer T71
- relocation of resistance temperature detectors on T71
- replacement of 46kV potential transformers
- replacement of capacitor bank risers
- replacement of switchyard flood lights for auto transformers

Background (This section is be filled out only if there is information relevant to the recommendation).

The decrease of $10.0 million to project costs may be attributed to not requiring all of the Contingency that was identified under the previous CPJ Addendum, along with elimination of forecast escalation, and lower capitalized interest. The details are as follows:

a) Project Risk (decrease of $7.9 million)
   - $4.7 million of Contingency planned for potential changes to design and material procurement costs under the Engineer & Procure contract.
   - $2.8 million of Contingency planned for Electrical & Overhead Construction, for stakeholder milestone delays, material defects and delays, and winter construction
   - $0.4 million of Contingency planned for various risks associated with the work at other stations (Ridgeway, Transcona and St. Vital).

b) Interest and Escalation (decrease of $2.1 million)
   Decrease of $1.2 million to forecast escalation now that work is substantially complete, plus a decrease of $0.9 million to capitalized interest now that the project is fully in service.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

Establishing a 230/500kV station at Riel and sectionalizing the 500kV line between Dorsey and Forbes (D602F) allows power to be imported during a catastrophic Dorsey outage, as well as provides an alternate path for power export during a Dorsey transformer outage.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability: Outage-related	Operational Enhancement	New Asset Addition & Asset Improvement	60%	$191,952,000
Reliability: Load-related	Capacity Enhancement	New Asset Addition & Asset Improvement	20%	$ 63,983,000
Reliability: Load-related	New/Increased Generation Delivery	New Asset Addition & Asset Improvement	20%	$ 63,983,000
				$319,918,000

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	**NPV Benefits (Costs)**
No Change.	

Other Alternatives Considered	**NPV Benefits (Costs)**

Project Risk Analysis (This section is be filled out only if there is a change to the project risk).

The revised project estimate includes $0.36 million of Contingency applicable to the Engineer and Procure contract. This Contingency is allocated for close-out of contract deficiencies and warranties.

There's a risk to the project schedule in association with completion of the project deficiencies, some of which require an outage on the 500kV transmission lines (D603M from Dorsey to Riel and M602F from Riel to Forbes). An outage has been secured for October 2015; however, in the event this outage is cancelled, all deficiencies and remaining work planned for completion during the outage will need to be rescheduled to the next available opportunity, which is limited to the spring or fall timeframes.

Capital Budget Estimate (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 214,407	$ 214,407	$ 0
2013/14	$ 74,057	$ 73,510	$ (546)
2014/15	$ 40,792	$ 29,160	$ (11,632)
2015/16	$ 682	$ 2,840	$ 2,159
Total	$ 329,937	$ 319,918	$ (10,019)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The 230kV yard was placed in service in May 2014 and the 500kV yard in October 2014.

The remaining work is scheduled to be completed before the end of fiscal 2015/16, at which time the project will be closed out (unless the October 2015 outage is cancelled and has to be rescheduled for some time in 2016/17).

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

Commissioning Certificate No. 3629

Section:	Submission Appendix 2	**Page No.:**	Page 3 Page 12, Footnote 7
Topic:	Functionalization		
Subtopic:	Riel		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

The Submission states that "it is also Manitoba Hydro's intention to functionalize the upcoming Riel Converter facilities on this basis (i.e., as generation)". Appendix 2 notes that the Riel Station is comprised of two separate projects – the Riel Reliability Project and the Bipole III Reliability Project.

QUESTION:

b) Please describe what other facilities, besides the converter, will be located at the Riel Station.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Riel.

RESPONSE:

Riel converter station consists of a several facilities including the HVdc converter station, 230 kV and 500 kV switchyards, as well as a 230 kV to 500 kV transformer bank.

Section:	Submission Appendix 2	**Page No.:**	Page 3 Page 12, Footnote 7
Topic:	Functionalization		
Subtopic:	Riel		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

The Submission states that "it is also Manitoba Hydro's intention to functionalize the upcoming Riel Converter facilities on this basis (i.e., as generation)". Appendix 2 notes that the Riel Station is comprised of two separate projects – the Riel Reliability Project and the Bipole III Reliability Project.

QUESTION:

c) What is the relative forecast cost (i.e., gross investment) of: i) all of the facilities at the Riel Station; ii) the facilities associated with the Bipole III Project and iii) the cost of the converter facilities at Riel?

d) Is it Manitoba Hydro intention to functionalize the entire cost of the Riel station as generation, just the costs associated with the Bipole III project or just the cost of the converter facilities at Riel?

e) If the intention is to functionalize as generation more than just the cost of the converter facilities, please explain why this appropriate.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Riel.

RESPONSE:

c) The Bipole III Riel Converter Station represents the southern terminus of the Bipole III transmission line, east of Winnipeg. The scope of the Riel Converter Station includes the converter equipment (valve halls, converter transformers and DC yard), four 250 MVar

Synchronous Condensers and associated equipment. The scope also includes the expansion of the existing 230 kV AC Yard to accommodate the synchronous condensers, HVdc converters and transmission lines.

- The forecast cost for the Riel Converter Station is $1,194 Million

The Riel Reliability Project (or Riel Sectionalization Project) preceded the Bipole III Riel Converter Station and included the development of 500 kV and 230 kV ac switchyards, and 230 kV connections to the southern receiver system serving Winnipeg and southern Manitoba. Site preparation and infrastructure development for the sectionalization project extended, in part, to that required for the Bipole III portion of Riel.

- The cost for the Riel Reliability Project is $312 Million

d) It is Manitoba Hydro's intention to functionalize only the converter facilities at Riel Station as Generation.

e) Please see Manitoba Hydro's response to part d).

Section:	Submission Appendix 2 MISO Transmission Owners Agreement MISO Business Practice Manual BPM-028 – Transmission Determination Process	**Page No.:**	Page 3 Page 12, Footnote 7
Topic:	Functionalization		
Subtopic:	Riel		
Issue:	Treatment as Generation		

PREAMBLE TO IR (IF ANY):

It is noted that the MISO Transmission Owners Agreement (TOA) requires MISO to make a transmission determination for a prospective or existing Transmission Owner where the Transmission Owner is not subject to regulation by a regulatory authority (i.e., FERC or a State Commission). (TOA Appendix C, Part II, Section C, Paragraph 2)

The referenced MISO Business Practice Manual can be found at

https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

QUESTION:

a) Please provide Manitoba Hydro's view as to whether each of the following would meet the definition of transmission as set in the applicable MISO Business Practice Manual and explain why:

i. The Riel Bipole III Project facilities – excluding the converter
ii. The Riel Bipole III Project converter
iii. The Riel Reliability Project facilities.

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Riel.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH I-37.

Section:	Appendix 3.1	Page No.:	Page 27 Page 64 (Schedule E1)
Topic:	Functionalization		
Subtopic:	Distribution		
Issue:	Sub-Functionalization of Distribution Plant		

PREAMBLE TO IR (IF ANY):

It is noted that Distribution Plant is sub-functionalized into Substations, Lines, Transformers, Services, Meters, Meter Maintenance and Serialized Equipment for purposes of applying various allocation factors.

QUESTION:

a) Please explain how for each of Depreciation and Operating costs the total costs allocated to Distribution Plant (per Schedules C6 and C12) were subsequently allocated to these sub-functions. As part of the response please fully explain the derivation of any allocation base(s) used and provide a working excel model that sets how such allocation bases were employed to sub-functionalize the costs.

RATIONALE FOR QUESTION:

To understand the proposed sub-functionalization of Distribution Plant costs.

RESPONSE:

Cost center level detail is available from SAP for Distribution Poles & Wires, Distribution Transformers, and Meter Investment and Maintenance to facilitate sub-functionalization.

Costs of substations that are entirely distribution related are available in aggregate at the cost center level. Please see Manitoba Hydro's response to COALITION/MH 1-34c for a discussion of process used to functionalize multi-function substations and identify additional Distribution related substation costs.

Common Distribution costs tracked at the cost center level related to Research and Development, Planning & Records, Environmental and Hazardous Waste have been included in the Distribution Substation sub-function in the COS. The share of Communication plant that has been functionalized as Distribution in the COS is also included in the Distribution Substation sub-function.

No additional sub-fuctionalization of Distribution Depreciation and Operating is conducted as part of preparation of the COS study.

Section:	Appendix 4 Appendix 5	Page No.:	Pages 11 and 12 Page 20
Topic:	Functionalization		
Subtopic:	Distribution Plant		
Issue:	Primary vs. Secondary Distribution		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) What voltages does Manitoba Hydro consider to be primary distribution and what voltages are secondary distribution?

b) How was the 70/30 cost split for primary versus secondary distribution referred to on page 11 determined?

c) What rate classes receive power at secondary voltages? In each case, please indicate the percentage of load (in terms of NCP1 or energy) that is delivered at secondary voltages?

d) Are there customers that receive power at a secondary voltage but do not utilize any of Manitoba Hydro's lines that operate at secondary voltages (i.e. , the customer owns the line that connects to the Manitoba Hydro owned transformer stepping power down to a secondary voltage)?

e) If the response to part (d) is yes, what rate classes utilize lines operating at secondary voltages? In each case, please indicate the percentage of load utilizing secondary voltage lines? Note: This percentage should be expressed as a percentage of the class' total NCP1 or, if not available, as a percentage of the class' total energy.

f) Why didn't Manitoba Hydro simply create two separate sub-functions: one for primary lines and another for secondary lines as recommended by CA in Appendix 5 (page 20 – second bullet of Recommendation)? What would be the problems with doing so?

RATIONALE FOR QUESTION:

To understand the proposed functionalization of Distribution Plant costs.

RESPONSE:

a) Manitoba Hydro considers primary distribution (high voltage) to include any plant operated above 750 volts while secondary distribution (low voltage) includes any plant operated at 750 volts or less.

b) Please see Manitoba Hydro's response to PUB/MH I-49.

Response to parts c), d) and e):

Customers in the Residential, General Service Small, General Service Medium and Area & Roadway Lighting customer classes are served at secondary voltages.

Customers with a point of delivery at the secondary bushings of a Corporation provided transformer, would not utilize any of the Corporation's secondary distribution. General Service Small and Medium customers may be offered a point of delivery at the secondary bushings of a Corporation transformer, if their service request is over four hundred amps.

While the Corporation does not maintain data on the point of delivery for customer classes, it is estimated that approximately 3% of the General Service Medium class load (on an energy basis) is served at primary voltages.

f) While the creation of primary and secondary voltage sub-functions was a recommended approach, the implementation of such a recommendation requires the availability of more detailed plant records. Manitoba Hydro determined that its plant records would not provide sufficient detail in all cases to support this sub-functionalization. Absent the appropriate level of information, any assignment of assets to each sub-function would require subjective judgment, which may be no more precise than the current approach of applying a 70/30 split upon allocation.

Section:	Appendix 3.1	Page No.:	Page 64 (Schedule E1)
Topic:	Functionalization		
Subtopic:	Distribution Services		
Issue:	Cost Assignment to Sub-Functions		

PREAMBLE TO IR (IF ANY):

For purposes of allocation costs, costs in the Distribution Services function are sub-functionalized into: Customer Service – General; Customer Acct. – Billing; Customer Acct. – Collections; Marketing R&D; Inspection and Meter Read.

QUESTION:

a) Please indicate how the Operating costs assigned to Distribution Services are assigned to the six sub-functions. As part of the response please fully explain the derivation of any allocation base(s) used and provide a working excel model that sets how such allocation bases were employed to sub-functionalized the costs.

b) Please indicate how the Deprecation costs assigned to Distribution Services are assigned to the six sub-functions. As part of the response please fully explain the derivation of any allocation base(s) used and provide a working excel model that sets how such allocation bases were employed to sub-functionalize the costs.

c) Please confirm that Interest costs assigned to Distribution Services were pro- rated to the six sub-functions based on the Operating costs allocated to each. If not, please explain how Interest costs were allocated to the six sub-functions.

RATIONALE FOR QUESTION:

RESPONSE:

a) Cost center level detail is assigned through Manitoba Hydro's SAP system for costs related to the Distribution Services to facilitate sub-functionalization of the operating costs.

b) Cost center level detail is assigned through Manitoba Hydro's SAP system for costs related to the Distribution Services to facilitate sub-functionalization of the depreciation costs.

c) Confirmed.

Section:	Appendix 4	**Page No.:**	Page 8
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2012 Recommendations		

PREAMBLE TO IR (IF ANY):

With respect to Christensen Associates' recommendations regarding Generation classification and allocation Manitoba Hydro responded:

"MH will explore the impact of a greater degree of disaggregation (of time periods used) on the allocation of generation costs over the next year or so."

MH is not convinced that the Equivalent Peaker methodology would be an improvement over the current method but will explore its possible impacts."

QUESTION:

a) Please indicate what additional analysis Manitoba Hydro undertook to explore the impact of moving from 12 periods to a greater disaggregation of hours and provide the results.

b) Please indicate what additional analysis Manitoba Hydro undertook to explore the impact of the Equivalent Peaker methodology and provide the results.

RATIONALE FOR QUESTION:

To understand the follow-up Manitoba Hydro undertook regarding Christensen Associates' recommendations.

RESPONSE:

a) Following the advice provided by Christensen Associates in the supplemental review, Manitoba Hydro has pursued the option of improving the recognition of capacity in the weighted energy allocator through the addition of the value of capacity into on-peak hours.

Manitoba Hydro believes the use of hourly MISO pricing, 3x365 SEP prices or other greater disaggregation may result in a more precise allocation, but not offer any significant improvement in terms of recognizing energy price variability. The use of a greater number of periods will result in a larger peak to off-peak weighting difference, but would be offset by the smaller number of hours in each period. The evaluation undertaken as part of the 2005/06 Cost of Service review of moving from four to 12 period weightings, proved to be a limited driver of change in the allocation of Generation costs.

Due to the additional complexity and data requirements of greater disaggregation, and the limited impact experienced from previous disaggregation, Manitoba Hydro has not performed any analysis of further disaggregation of hours.

b) Please see Manitoba Hydro's response to MIPUG/MH I-10a.

Section:	Submission Appendix 3.1 PUB MFR #8 File – Derivation of Energy Weights for PCOSS14	Page No.:	Page 20 Page 56 (Schedule D2) Page 9
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With reference to PUB MFR#8, please provide the actual average SEP prices for the 12 periods for each of the years 1999 – 2006 as used to derive the marginal cost ratios used in PCOSS08.

b) Please provide a schedule that sets out the derivation of the marginal cost ratios used in PCOSS08 based on these SEP prices from part (a).

c) Please provide the actual average SEP prices for each of each of the 12 periods for each of the years used to derive the marginal cost ratios used in PCOSS14 (and PCOSS14-Amended).

d) What is the number of hours assumed to be associated with each of the 12 periods?

RATIONALE FOR QUESTION:

To understand the change in SEP prices since PCOSS08.

RESPONSE:

a) The table below contains the actual average SEP prices for the 12 periods for each of the years used to derive the marginal cost ratios used in PCOSS08. The SEP marginal weightings calculated for PCOSS08 were based on calendar years.

Cdn $ per kW.h

PCOSS08	Spring			Summer			Fall			Winter		
Actual Prices	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**
1999	0.0350	0.0310	0.0199	0.0426	0.0283	0.0147	0.0264	0.0203	0.0119	0.0341	0.0262	0.0209
2000	0.0384	0.0368	0.0189	0.0716	0.0700	0.0138	0.0617	0.0437	0.0183	0.0728	0.0390	0.0241
2001	0.0691	0.0564	0.0211	0.0703	0.0408	0.0124	0.0421	0.0304	0.0200	0.0802	0.0395	0.0261
2002	0.0474	0.0382	0.0271	0.0598	0.0397	0.0205	0.0509	0.0388	0.0232	0.0500	0.0309	0.0256
2003	0.0589	0.0430	0.0403	0.0726	0.0498	0.0493	0.0515	0.0492	0.0494	0.0979	0.0694	0.0648
2004	0.0603	0.0476	0.0318	0.0513	0.0371	0.0195	0.0498	0.0412	0.0223	0.0809	0.0543	0.0495
2005	0.0534	0.0517	0.0341	0.0905	0.0720	0.0098	0.0695	0.0589	0.0168	0.0708	0.0554	0.0409
2006	0.0427	0.0411	0.0074	0.0672	0.0476	0.0216	0.0741	0.0688	0.0668	0.0632	0.0528	0.0406

b) The following schedule shows the derivation of marginal weights used in PCOSS08. The marginal weights are based on average inflation-adjusted prices for each of the 8 years 1999-2006.

SEP AVERAGE INFLATION-ADJUSTED PRICES JANUARY 1, 1999 - December 31, 2006				HOURS IN MONTH				HOURS X PRICE IN MONTH			
Month	**Peak**	**Shoulder**	**Off-Peak**	**Days**	**Peak**	**Shoulder**	**Off-Peak**		**Peak**	**Shoulder**	**Off-Peak**
1	$73.67	$49.12	$38.73	31.0	177.14	318.86	248.00	Winter	13,049.49	15,660.87	9,604.01
2	$67.88	$48.14	$41.33	28.3	161.43	290.57	226.00	Winter	10,957.13	13,989.26	9,339.51
3	$68.08	$49.01	$39.81	31.0	177.14	318.86	248.00	Winter	12,060.67	15,627.54	9,872.83
4	$59.34	$45.80	$30.87	30.0	171.43	308.57	240.00	Spring	10,171.93	14,133.96	7,409.44
5	$49.92	$47.23	$23.33	31.0	177.14	318.86	248.00	Spring	8,843.79	15,060.84	5,786.53
6	$64.22	$46.36	$17.00	30.0	171.43	308.57	240.00	Summer	11,008.87	14,304.69	4,080.27
7	$85.57	$56.72	$21.88	31.0	177.14	318.86	248.00	Summer	15,158.80	18,086.91	5,427.26
8	$76.51	$61.93	$25.85	31.0	177.14	318.86	248.00	Summer	13,553.62	19,745.27	6,410.80
9	$55.91	$41.86	$21.94	30.0	171.43	308.57	240.00	Summer	9,584.32	12,917.19	5,265.76
10	$51.06	$48.23	$27.23	31.0	177.14	318.86	248.00	Fall	9,045.33	15,379.52	6,752.96
11	$63.06	$45.29	$33.47	30.0	171.43	308.57	240.00	Fall	10,810.40	13,974.11	8,032.43
12	$85.55	$50.03	$36.32	31.0	177.14	318.86	248.00	Winter	15,155.22	15,952.56	9,006.76

COSTING PERIODS *(SAME AS TOU REPORT)* :

Spring: April through May

Peak :	7:00 to 11:00 a.m. to 4:00p.m. to 8:00 p.m. Weekdays
Shoulder :	11:00 a.m. to 4:00 p.m. Weekdays; 8:00 p.m. to 11:00 p.m. Weekdays
	7:00 a.m. to 11:00 p.m. Weekends
Off Peak :	11:00 p.m. to 7:00 a.m. all days

Summer: June through September

Peak :	12:00 Noon to 8:00 p.m. Weekdays
Shoulder :	7:00 a.m. to 12:00 noon ; 8:00 p.m. to 11:00 p.m. Weekdays.
	7:00 a.m. to 11:00 p.m. Weekends
Off Peak :	11:00 p.m. to 7:00 a.m. all days

Fall: Oct through November

Peak :	7:00 to 11:00 a.m. to 4:00p.m. to 8:00 p.m. Weekdays
Shoulder :	11:00 a.m. to 4:00 p.m. Weekdays; 8:00 p.m. to 11:00 p.m. Weekdays
	7:00 a.m. to 11:00 p.m. Weekends
Off Peak :	11:00 p.m. to 7:00 a.m. all days

Winter: December through March

Peak :	7:00 to 11:00 a.m. to 4:00p.m. to 8:00 p.m. Weekdays
Shoulder :	11:00 a.m. to 4:00 p.m. Weekdays; 8:00 p.m. to 11:00 p.m. Weekdays
	7:00 a.m. to 11:00 p.m. Weekends
Off Peak :	11:00 p.m. to 7:00 a.m. all days

Hour Weighted Average Price (Cdn$ per kW.h)

Spring Season:	0.0546	0.0465	0.0270
Summer Season:	0.0707	0.0518	0.0217
Fall Season:	0.0570	0.0468	0.0303
Winter Season:	0.0739	0.0491	0.0390

Marginal Cost Weighting

Spring Season:	2.513	2.144	1.246
Summer Season:	3.258	2.388	1.000
Fall Season:	2.624	2.155	1.396
Winter Season:	3.406	2.262	1.796

c) The table below contains actual average SEP prices used to derive the marginal weights in both PCOSS14 and PCOSS14-Amended. The SEP marginal weightings calculated for PCOSS14 & PCOSS14-Amended were based on fiscal years.

Cdn $ per kW.h

PCOSS14 Prices	Spring			Summer			Fall			Winter		
	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak
2005	0.0661	0.0488	0.0318	0.0568	0.0375	0.0195	0.0537	0.0418	0.0223	0.0756	0.0489	0.0356
2006	0.0561	0.0509	0.0341	0.0973	0.0727	0.0098	0.0780	0.0587	0.0168	0.0735	0.0546	0.0400
2007	0.0471	0.0399	0.0074	0.0726	0.0495	0.0216	0.0764	0.0690	0.0668	0.0936	0.0660	0.0597
2008	0.0712	0.0616	0.0418	0.0768	0.0424	0.0134	0.0548	0.0410	0.0160	0.0828	0.0590	0.0391
2009	0.0588	0.0480	0.0251	0.0751	0.0461	0.0128	0.0551	0.0426	0.0212	0.0607	0.0439	0.0310
2010	0.0293	0.0247	0.0127	0.0296	0.0210	0.0080	0.0317	0.0253	0.0140	0.0476	0.0339	0.0254
2011	0.0293	0.0265	0.0192	0.0408	0.0266	0.0119	0.0289	0.0241	0.0117	0.0366	0.0270	0.0193
2012	0.0250	0.0214	0.0112	0.0315	0.0212	0.0085	0.0260	0.0198	0.0119	0.0279	0.0220	0.0172

d) The table below represents the average hours assumed in the twelve periods in the Weighted Energy allocator

	Hours per Period		
	Peak	**Shoulder**	**Off Peak**
Spring	328	648	488
Summer	671	1281	976
Winter	661	1279	970
Fall	339	637	488

Section:	Appendix 2 Appendix 1	Page No.:	Pages 18-21 Page 7
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Christensen Associates' 2015 Supplemental Report makes reference to the appearance of voluntary MISO capacity markets as the reason for needing to include a measure of capacity costs within the weighted energy allocator. Manitoba Hydro's response states that the "CRP reference discount incorporated in the weightings is well in excess of current market prices for capacity.

QUESTION:

a) When did MISO's voluntary capacity markets first start to operate?

b) Please outline how the market generally works.

c) Does the MISO capacity market have a definition of on-peak that is used and, if so, what is it?

d) Please provide some indication as to the scope and scale of MISO's capacity market (as compared to its energy market): i) as it existed in 2012 and ii) as it exists today.

e) Please provide a schedule setting out the price for capacity established for each year since the market started.

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

a) The MISO Voluntary Capacity Auction was implemented in April 2009. However, Manitoba Hydro did not participate as an external market participant in the MISO capacity market until the implementation of the MISO Planning Resource Auction (PRA) in March 2013 (for delivery starting June 2013).

b) In MISO, the Planning Resource Adequacy process is used to ensure that Load Service Entities (LSEs) have sufficient capacity resources to meet anticipated peak demand requirements plus an appropriate reserve margin.

The capacity resources used to achieve long-term resource adequacy are called Planning Resources. LSEs can supply their capacity from their own Planning Resources, by securing bilateral capacity contracts from other MISO market participants who have surplus Planning Resources or by participating in the Planning Resource Auction. LSEs purchasing capacity in the PRA for a particular Planning Year (June 1 through May 31) pay the Auction Clearing Price for the Load Resource Zone (LRZ) in which their load is located. The MISO market is separated into nine LRZs and Manitoba Hydro's capacity is currently deliverable into LRZ 1.

c) Capacity is deliverable at all times throughout the year and as a result there is no concept of on-peak or off-peak when discussing capacity.

d) For information about the MISO PRA auction clearing results for the 2015/16 planning year, including a comparison to the previous year please refer to:

https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2015-2016%20PRA%20Results.pdf

The estimated total value of cleared capacity for the 2015/16 planning year was US$ 540 million for all of MISO (see page 6 of the previous reference). However, only results for Zone 1 are relevant to Manitoba Hydro, with a value of cleared capacity of US$ 5 million for the 2015/16 planning year.

The MISO capacity market is small relative to the MISO energy market where gross energy market charges for 2014 were US$ 37 billion (see the following link to the MISO fact sheet).

https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf

e) The following table indicates the Auction Clearing Price (ACP) for the MISO PRA LRZ 1 since its implementation in planning year 2013/14:

Planning Year	ACP (US$/MW-Day)	ACP (US$/kW-Mth)
2013/14	$ 1.05	$0.032
2014/15	$ 3.29	$0.100
2015/16	$ 3.48	$0.106

Section:	Appendix 2 Appendix 1	Page No.:	Pages 18-21 Page 7
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Christensen Associates' 2015 Supplemental Report makes reference to the appearance of voluntary MISO capacity markets as the reason for needing to include a measure of capacity costs within the weighted energy allocator. Manitoba Hydro's response states that the "CRP reference discount incorporated in the weightings is well in excess of current market prices for capacity.

QUESTION:

f) Why did Manitoba Hydro choose to use the CRP reference discount as the value of capacity as opposed to the market price for capacity as established in the MISO capacity market?

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

Manitoba Hydro chose the CRP reference discount due to concerns about the low near term price and the potential volatility of MISO capacity market prices. Use of the reference discount also provides consistency between assumptions used by Manitoba Hydro to develop the CRP prices and cost allocation practices.

Section:	Appendix 2 Appendix 1	Page No.:	Pages 18-21 Page 4
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has reflected an additional capacity component in its Weighted Energy allocator by utilizing the value of capacity as represented by the Reference Discount used in the Curtailable Rate Program (CRP) in the weighting factors. For use in the COS this capacity value is converted to an energy basis by dividing the Reference Discount by the monthly on-peak hours, and adding the hourly capacity costs to the on- peak energy prices. (Appendix 1, page 7)

QUESTION:

a) Please confirm that the CRP adder was included in the SEP on-peak prices for all eight years (2005-2012) used to establish the weighting factors.

b) Was the MISO capacity market operating during all these years and, if not, why is it appropriate to include the CRP adder for all eight years?

c) Please confirm that the CRP adder was calculated using the number of "on- peak" hours as defined for purposes of the SEP and the weighting factor periods used in the COSS and was then added to the price in these specific hours.

d) Please explain why the CRP adder was not calculated based on the on-peak hours as defined by MISO and for purposes of the CRP and added to these particular hours.

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

a) Confirmed.

b) The MISO capacity market did not begin to operate until 2009. Please see Manitoba Hydro's response to COALITION/MH I-56e.

c) Confirmed.

d) Please see Manitoba Hydro's response to COALITION/MH I-54c.

Section:	Appendix 2 Appendix 1	Page No.:	Pages 18-21 Page 4
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has reflected an additional capacity component in its Weighted Energy allocator by utilizing the value of capacity as represented by the Reference Discount used in the Curtailable Rate Program (CRP) in the weighting factors. For use in the COS this capacity value is converted to an energy basis by dividing the Reference Discount by the monthly on-peak hours, and adding the hourly capacity costs to the on- peak energy prices. (Appendix 1, page 7)

QUESTION:

e) What are the number of "on-peak" hours per month based on i) the SEP's definition of on-peak and ii) the CRP and MISO definition of on-peak?

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

On average there are 166 on-peak hours per month based on the SEP definition, as well as based on the CRP program's definition of peak.

There are 340 hours per month on average under the MISO definition of on-peak.

Section:	Appendix 2 Appendix 1	Page No.:	Pages 18-21 Page 4
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has reflected an additional capacity component in its Weighted Energy allocator by utilizing the value of capacity as represented by the Reference Discount used in the Curtailable Rate Program (CRP) in the weighting factors. For use in the COS this capacity value is converted to an energy basis by dividing the Reference Discount by the monthly on-peak hours, and adding the hourly capacity costs to the on- peak energy prices. (Appendix 1, page 7)

QUESTION:

f) What are the number of "shoulder" hours per month based on the SEP's definition of the shoulder period?

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

On average there are 320 shoulder hours per month based on the SEP definition.

Section:	Appendix 2 Appendix 1	**Page No.:**	Pages 18-21 Page 4
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Christensen Associates' 2015 Recommendations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has reflected an additional capacity component in its Weighted Energy allocator by utilizing the value of capacity as represented by the Reference Discount used in the Curtailable Rate Program (CRP) in the weighting factors. For use in the COS this capacity value is converted to an energy basis by dividing the Reference Discount by the monthly on-peak hours, and adding the hourly capacity costs to the on- peak energy prices. (Appendix 1, page 7)

QUESTION:

g) Which "on-peak" definition does Manitoba Hydro plan on using for its proposed industrial time of use rates?

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

In Order 26/16, the PUB determined that Time-of-Use rates would be excluded from the scope of the Cost of Service Methodology Review and will be dealt with at the next General Rate Application. Accordingly, a response to this Information Request is not required.

Section:	Submission Appendix 4 Appendix 2 Appendix 1 2005 Cost of Service Methodology Review, CAC/MSOS/MH I-11 c)	Page No.:	Page 20 Page 8 Pages 18-19 Page 7
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

In Appendix 1 Manitoba Hydro states that it "accepts that due to changes in market conditions, the capacity component of energy supply may not be adequately reflected in the differential between on-peak and off-peak prices".

In comparison, at the time of the last COSS review Manitoba Hydro stated "Manitoba Hydro believes that the on-peak/off-peak differential in SEP rates can act as a reasonable proxy for capacity considerations as well as energy considerations". (CAC/MSOS/MH I-11 c))

QUESTION:

a) What is the definition of on-peak and off-peak as used in the quote referenced from Appendix 1?

b) Are these definitions the same as those used in Manitoba Hydro's response to CAC/MSOS/MH I-11 c)? If not, please indicate what the difference is.

c) Please provide a schedule that sets out by season and by year the average on- peak and off-peak SEP prices and the resulting on-peak/off-peak ratios for the period 1999 to 2015 using the period definitions from part (a).

d) If different from the response to part (c), please provide a schedule that sets out by season and by year the average on-peak and off-peak SEP prices and the resulting on-peak/off-peak ratios for the period 1999 to 2015 using the MISO's definition of the peak period.

e) When did market conditions change such that "the capacity component of energy supply may not be adequately reflected in the differential between on-peak and off-peak prices". Please also comment on the extent to which this change is evident in the history of price differentials provided in response to part (c) and (d).

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

a) In Appendix 4 (page 8) of Manitoba Hydro's Submission, Manitoba Hydro notes that it believes that capacity costs are reflected, at least in part, in the differential between on-peak energy values and energy values in other time periods. But given the capacity market in MISO, it would consider whether further capacity in each time period could be incorporated into the weights.

The quote in Appendix 1 is in reference to on-peak and off-peak prices observed in the MISO market.

b) In Manitoba Hydro's 2005 response to CAC/MSOS/MH I-11c) the definition of on and off-peak was consistent with the MISO definition of peak, but also further differentiated the prices into Winter and Summer seasons.

Winter: November through April
Peak: 7:00 to 11:00 p.m.
Off-Peak: all other hours

Summer: May through October
Peak: 7:00 to 11:00 p.m.
Off-Peak: all other hours

c) The table below provides average actual SEP prices for the on-peak and off-peak periods by fiscal year and season.

The current MISO definition of on- and off-peak periods is used in this response and is consistent with the periods defined in COALITION-MH-I-58b. The Summer Season spans May through October and the Winter Season spans November through April.

Summer: May through October
Winter: November through April

The on-peak period is the 5x16 period (5 days a week 16 hours a day, hour ending 7 to hour ending 22, Central Prevailing Time) excluding NERC holidays. All hours which do not fall within the on-peak period are considered off-peak hours.

Fiscal Year	Season	*On-Peak Price ($/MWh)*	*Off-Peak Price ($/MWh)*	*On/Off Peak Ratio*
1999/2000	Summer	$34.64	$18.70	1.85
1999/2000	Winter	$34.29	$19.11	1.79
1999/2000 Total		**$34.46**	**$18.90**	**1.82**
2000/01	Summer	$76.34	$20.05	3.81
2000/01	Winter	$77.71	$31.36	2.48
2000/01 Total		**$77.01**	**$25.69**	**3.00**
2001/02	Summer	$58.95	$20.89	2.82
2001/02	Winter	$45.98	$26.89	1.71
2001/02 Total		**$52.56**	**$23.88**	**2.20**
2002/03	Summer	$49.70	$26.88	1.85
2002/03	Winter	$74.13	$48.95	1.51
2002/03 Total		**$61.77**	**$37.86**	**1.63**
2003/04	Summer	$59.31	$43.83	1.35
2003/04	Winter	$69.24	$51.44	1.35
2003/04 Total		**$64.24**	**$47.62**	**1.35**
2004/05	Summer	$51.85	$25.96	2.00
2004/05	Winter	$58.58	$35.71	1.64
2004/05 Total		**$55.25**	**$30.74**	**1.80**
2005/06	Summer	$79.74	$28.26	2.82
2005/06	Winter	$64.68	$41.36	1.56
2005/06 Total		**$72.18**	**$34.73**	**2.08**
2006/07	Summer	$61.28	$32.48	1.89
2006/07	Winter	$75.06	$53.49	1.40
2006/07 Total		**$68.06**	**$42.97**	**1.58**
2007/08	Summer	$59.27	$18.58	3.19
2007/08	Winter	$72.44	$42.86	1.69
2007/08 Total		**$65.78**	**$30.72**	**2.14**
2000/09	Summer	$58.72	$20.55	2.86
2008/09	Winter	$56.06	$32.59	1.72
2008/09 Total		**$57.41**	**$26.54**	**2.16**
2009/10	Summer	$26.94	$12.40	2.17
2009/10	Winter	$36.75	$24.99	1.47
2009/10 Total		**$31.80**	**$18.62**	**1.71**
2010/11	Summer	$33.21	$18.20	1.82
2010/11	Winter	$29.62	$20.46	1.45
2010/11 Total		**$31.40**	**$19.31**	**1.63**
2011/12	Summer	$24.93	$12.56	1.98
2011/12	Winter	$25.78	$18.46	1.40
2011/12 Total		**$25.36**	**$15.49**	**1.64**

Fiscal Year	Season	*On-Peak Price ($/MWh)*	*Off-Peak Price ($/MWh)*	*On/Off Peak Ratio*
2012/13	Summer	$24.88	$16.10	1.55
2012/13	Winter	$30.09	$23.59	1.28
2012/13 Total		**$27.45**	**$19.84**	**1.38**
2013/14	Summer	$27.73	$16.02	1.73
2013/14	Winter	$49.32	$34.80	1.42
2013/14 Total		**$38.40**	**$25.36**	**1.51**
2014/15	Summer	$21.46	$11.80	1.82
2014/15	Winter	$35.73	$26.33	1.36
2014/15 Total		**$28.51**	**$19.03**	**1.50**

d) Please see Manitoba Hydro's response to part c).

e) Manitoba Hydro has incorporated a capacity adder based on the advice provided by Christensen Associates that capacity may not sufficiently be reflected in energy price differentials on a go-forward basis. CA identified the establishment of a voluntary capacity market in MISO in 2009 as the time that market conditions changed:

> *In view of recent developments in the structure of MISO wholesale markets—namely, the appearance of voluntary capacity markets—capacity costs should also be considered for inclusion in MH's weighted energy calculations. Prior to the appearance of MISO capacity markets, capacity costs were accounted for, arguably, by the scarcity rent content implicit within observed energy prices. (page 18, CA Supplemental Report)*
>
> *Second, MISO capacity auction prices are currently low and reflect very limited participation, suggesting that, since 2009, scarcity rent content is similarly small, even in the absence of capacity markets over much of this period. (page 20, CA Supplemental Report)*

The perspective provided by CA was developed through an examination of the market conditions that contributed to the on/off peak differential, and not through observations of the changes in price differentials. None the less, an initial comparison of the ratio of on-peak to off-peak prices in the pre and post 2009 timeframes would appear to support the argument that the pricing relationship changed with the introduction of the VCA in MISO.

	Average On/Off Peak Ratio		
	Annual	**Summer**	**Winter**
1999/00 to 2008/09	2.0	2.4	1.7
2009/10 to 2014/15	1.6	1.8	1.4
Percent Decrease	-21%	-25%	-17%

However, higher on-peak prices can reflect both the higher variable cost of generation resources used to meet peak demands, as well as scarcity rent content. Since the changes in MISO markets largely coincided with the 2008 economic downturn and drop in natural gas prices, the changes in the on/off-peak ratio cannot be reasonably attributed entirely to a reduction in scarcity premiums.

Section:		Page No.:	
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update the response to CAC/MSOS/MH II-26 a) using Manitoba Hydro's marginal costs for generation as of IFF12.

b) Please confirm the definition of winter versus summer and on-peak versus off- peak used.

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

a) The following provides an update of Manitoba Hydro's response to CAC/MSOS/MH II-26 a) from the 2005 Cost of Service Methodology Review. The values presented are based on information as of IFF12 and reflect Manitoba Hydro's estimate of long run marginal cost to serve the firm load levelized over a 35-year period. It should be noted that marginal costs are a function of a number of factors such as development plan sequence, fuel costs, market prices, capacity cost and discount rates. As a result, the ratios provided are not directly comparable from year to year.

Summer Off-Peak	1.00
Winter Off-Peak	3.20
Summer On-Peak	1.67
Winter On-Peak	3.61

As noted in the response to CAC/MSOS/MH II-26a), Manitoba Hydro's methods for determining long run marginal costs do not include algorithms which are capable of estimating any differential between peak and off peak energy related costs. Therefore, the on-peak versus off-peak differentials provided reflect only capacity related costs evenly distributed throughout the on-peak period hours.

b) Summer months include April to September and winter months include October to March. The 80 hours in a week (16 hours of 5 days, 6:00 AM to 10:00 PM) are defined as on-peak hours and the remaining 88 hours in the week (weekends and remaining 8 hours of the 5 days) are defined as off-peak hours.

Section:	2005 Cost of Service Methodology Review, CAC/MSOS/MH II-26 a)	**Page No.:**	
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Based on the SEP prices used to calculate the marginal cost weighting factors in PCOSS14, please calculate the average SEP price for each period using the definitions from part (b).

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

	On-Peak Price ($/MWh)	***Off-Peak Price ($/MWh)***
Summer	$54.70	$24.68
Winter	$56.55	$36.13
Total	**$55.63**	**$30.40**

Section:	2005 Cost of Service Methodology Review, CAC/MSOS/MH II-26 a)	**Page No.:**	
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please update the response to CAC/MSOS/MH II-26 a) using Manitoba Hydro's most recent marginal costs for generation.

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

The following provides an update of Manitoba Hydro's response to CAC/MSOS/MH II-26 a) from the 2005 Cost of Service Methodology Review. The values presented are based on 2015 information and reflect Manitoba Hydro's estimate of long run marginal cost to serve the firm load levelized over a 35-year period. It should be noted that marginal costs are a function of a number of factors such as development plan sequence, fuel costs, market prices, capacity cost and discount rates. As a result, the ratios provided are not directly comparable from year to year.

Summer Off-Peak	1.00
Winter Off-Peak	1.89
Summer On-Peak	1.53
Winter On-Peak	2.42

As noted in the response to CAC/MSOS/MH II-26a), Manitoba Hydro's methods for determining long run marginal costs do not include algorithms which are capable of estimating any differential between peak and off peak energy related costs. Therefore, the on-peak versus off-peak differentials provided reflect only capacity related costs evenly distributed throughout the on-peak period hours.

Section:	2015/16 &2016/17 GRA, COALITION/MH I-71	Page No.:	
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Determination of Marginal Cost Weightings		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update the response to COALITION/MH I-71 to include a full year of data for 2014/15.

b) Please confirm the definition of on-peak versus off-peak used.

c) Please calculate the average SEP on-peak price for each year included in the response to COALITION/MH I-71 using the on-peak definition from part (b).

RATIONALE FOR QUESTION:

To understand the proposal to incorporate a capacity adder into the weighted energy allocator.

RESPONSE:

a)

TOTAL ON-PEAK SALES						
	DEPENDABLE ON-PEAK SALES			**OPPORTUNITY ON-PEAK SALES**		
	GWh	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**
2005/06	3,742	228	60.62	3,142	245	72.73
2006/07	3,510	211	59.69	1,972	135	66.26
2007/08	3,612	198	54.56	2,212	162	66.19
2008/09	3,702	221	59.4	1,802	153	71.78
2009/10	3,073	180	58.15	2,497	84	31.14
2010/11	3,051	164	53.58	2,268	76	31.90
2011/12	3,240	164	50.38	1,952	59	28.76
2012/13	3,178	166	51.87	2,165	69	29.87
2013/14	2,930	168	56.82	2,492	82	36.95
2014/15	2,735	172	62.62	2,264	84	35.98

b) The definition of the on-peak period in part a) is the 5x16 period (5 days a week 16 hours a day, hour ending 7 to hour ending 22, Central Prevailing Time) excluding NERC holidays. All hours which do not fall within the above definition are considered off-peak.

c)

Fiscal Year	**Average On-peak Daily SEP Rate**
2005/06	$77.21
2006/07	$66.48
2007/08	$65.72
2008/09	$62.94
2009/10	$32.25
2010/11	$32.77
2011/12	$28.55
2012/13	$26.46
2013/14	$36.82
2014/15	$32.23

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	Page No.:	Page 17 Page 4 Page 2 Page 23 Page 5
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Wind		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Are all wind energy purchases considered to be dependable energy for purposes of Manitoba Hydro's resource planning?

b) If not, what portion of the wind purchases (kWh) are assumed to not be dependable energy for purposes of resource planning?

c) Do the contracts for wind power purchases distinguish between dependable and non-dependable energy? If so, over the last 5 years what portion of the payments have been associated with the purchase of dependable vs. non- dependable energy?

RATIONALE FOR QUESTION:

To understand the proposed treatment of wind generation in the COSS.

RESPONSE:

a) For resource planning purposes, Manitoba Hydro assumes that 85% of the expected average annual wind generation is considered as dependable energy.

b) As 85% of the expected average annual wind generation is considered as dependable energy, the other 15% would be considered as opportunity energy.

c) The specific details of the wind power purchase agreement including the portion of payments for dependable vs. non- dependable energy are confidential under the terms of the wind power purchase agreements.

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	Page No.:	Page 17 Page 4 Page 2 Page 23 Page 5
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Purchased Power		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Are there transmission service charges that Manitoba Hydro pays when making power purchases?

b) If so, does this include both Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) and Transmission Service from the MISO and other Transmission Providers' applicable OATTs, or just the later?

RATIONALE FOR QUESTION:

To understand the COSS treatment of transmission service costs (and revenues) associated with purchased power.

RESPONSE:

Under Manitoba Hydro's OATT, MH's Transmission Business Unit is separated and operates independently from Manitoba Hydro's export marketing group to ensure that all users of MH's transmission system have non-discriminatory access and non-preferential treatment for transmission information and services in Manitoba. For this reason Manitoba Hydro's Marketing group is required to seek service under the OATT as would any other user of the tariff.

Manitoba Hydro and the Midwest Independent Transmission System Operator, Inc. (MISO) have a Coordination Agreement that allows Manitoba Hydro to participate in MISO and remain compliant with Canadian law, which precludes Manitoba Hydro from signing the Midwest ISO's transmission owners' agreement.

Under the Coordination Agreement transmission access, tariffs and tariff administration, and reliability and planning functions, are coordinated. The Coordination Agreement provides significant benefit to Manitoba Hydro.

a) Yes. For energy purchases from MISO to serve Manitoba load, Manitoba Hydro Marketing is responsible for transmission service charges to Manitoba Hydro Transmission for transmission service in Manitoba incurred under the Manitoba Hydro OATT. As this is an intercompany transaction, there is no net cost to Manitoba Hydro. For these same purchases MISO waives transmission service charges in MISO in accordance with the Coordination Agreement between Manitoba Hydro and MISO.

   For energy purchased from other markets there are transmission charges or equivalent fees for transmission service in those markets under the associated market (non-MISO) OATT (e.g. SaskPower OATT charges when purchasing from Alberta). In addition there are some small fees paid to MISO for these non-MISO transactions for tariff services in its role as Manitoba Hydro’s transmission tariff administrator.

b) Please see the response to part a).

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	**Page No.:**	Page 17 Page 4 Page 2 Page 23 Page 5
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Purchased Power		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) What costs for such Transmission Services are included in the PCOSS14 and where are such Transmission costs included in the COSS (e.g., are these charges included in the cost of Purchased Power or are they included in the Transmission function costs)?

d) If the costs include Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) where are the revenues reflected in the COSS?

RATIONALE FOR QUESTION:

To understand the COSS treatment of transmission service costs (and revenues) associated with purchased power.

RESPONSE:

c) The OATT fees paid by Manitoba Hydro are included in the cost of Purchased Power.

d) The OATT revenues are reflected in Export Revenues in the COSS.

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	Page No.:	Page 17 Page 4 Page 2 Page 23 Page 5
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Purchased Power		

PREAMBLE TO IR (IF ANY):

In response to Christensen Associates' first report Manitoba Hydro agreed with the recommendation to assign purchased power costs against exports (Appendix 4).

However, in its response to Christensen Associates Supplemental Report Manitoba Hydro indicated that it would allocate purchased power cost proportionally to all load (including opportunity exports).

QUESTION:

a) Please clarify what is meant by "proportionally".

b) This change in treatment appears to be based, in part, on a difference in view as to the basis for establishing cost responsibility. Christensen Associates' initial recommendation appears to be based on the role of purchases in median water year (which is the basis for the COSS). In contrast, Manitoba Hydro's proposal appears to be based on a different cost responsibility perspective which considers the role/use of purchased power under the range of conditions that could exist. Does Manitoba Hydro agree that this was one of the reasons for the changed treatment of Purchased Power? If not, please explain.

c) Has Manitoba Hydro used this same perspective regarding cost responsibility throughout its proposed COSS methodology?

RATIONALE FOR QUESTION:

To understand the proposed COSS treatment of Purchased Power costs.

RESPONSE:

a) Proportional allocation means that the power purchases are pro-rata shared between domestic, dependable, and opportunity sales based on their respective total energy.

b) Yes. While the views of Manitoba Hydro and CA are largely consistent, Manitoba Hydro views it preferable that consideration be given to resource use in conditions beyond explicit median flows for the reasons discussed below, as well as to avoid the potential illogical outcome that a resource cost be un-allocatable. As per the Submission (pages 16-23):

"Manitoba Hydro has also further considered past treatments of its generation resources including natural gas, coal and wind for purposes of export cost responsibility. On the basis that these resources support Domestic and Dependable export loads under some conditions and from a long term cost responsibility perspective, Manitoba Hydro intends to aggregate these costs to be allocated to Domestic and Dependable loads. Past extensive and complex reviews of the use of each of these resources in median flow conditions that underpins revenue requirement and COS has prompted a change to this simpler yet reasonably cost causative methodology.

Similarly, power purchases, trading desk and MISO fees support all load under some conditions and Manitoba Hydro intends to assign these costs proportionately to all load"

c) Manitoba Hydro believes it has reflected this perspective throughout its proposed methodology other than NEB fees, as discussed in COALITION/MH I-16e, which likely should have been pooled but do not materially impact cost of service in any event.

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	**Page No.:**	Page 17 Page 4 Page 2 Page 24-25 Page 6
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Thermal Generation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) What was the justification for each of Manitoba Hydro's thermal stations when they were first constructed?

b) What role or purpose do they each play in Manitoba Hydro's current resource planning?

c) What is the anticipated operation of each station under low, median and high water flow conditions?

RATIONALE FOR QUESTION:

To understand the proposed COSS treatment of thermal generating stations.

RESPONSE:

a) Existing thermal plants were justified to meet long term Manitoba load requirements.

b) Manitoba Hydro's thermal resources fill the following roles:

- They are a source of capacity under high system loading conditions and contribute to Manitoba Hydro's planning capacity reserves. When the Manitoba load is high, generally during cold winter weather, thermal generation can be used to meet peak system demand.

- They are a source of energy under low water flow/drought conditions. Under low water conditions, when lower cost import energy in unavailable, thermal generation can be used to provide energy to meet system requirements. As indicated in part c) of this response the lower the water flow, the greater will be the anticipated thermal plant operations for energy supply.

- Generation support prior to or during system emergencies such as ice storms or tornadoes. During weather events such as these that have the potential to damage transmission lines in southern Manitoba, thermal generation will be activated. This is an issue in the Brandon area which is highly dependent on the major transmission grid for its energy supply. Local generation can also be required during transmission line maintenance, or for the supply of reactive power. Reactive power is important for voltage control, to reduce transmission losses, and to maintain the stability of the electrical system.

- Emergency supply in the event of an extended loss of a major system element such as an HVDC bipole. In this circumstance thermal generation would be activated to serve Manitoba load that might otherwise need to be curtailed.

In order to be in a position to generate power in these circumstances the thermal station operates routinely (regardless of water conditions) for staff training and proficiency and to verify that generation is available to serve Manitoba load on a highly reliable basis.

c) Projected operation of each thermal unit under minimum, maximum, and median flow conditions is provided in the tables below, along with average thermal unit operation. Actual operation will be influenced by the requirement to support the roles described in part b) above. All energies are reported at generation. The results are based on the Power Resource Plan that was used for IFF12.

	System Hydraulic Condition		
	Low Flow (GWh/yr)	Median Flow (GWh/yr)	High Flow (GWh/yr)
Brandon Unit 5	811	126	126
Brandon Units 6&7	2354	18	18
Selkirk	953	14	14
Total	4118	158	158

Note: **Energy referenced to generation.**

Section:	Submission Appendix 1 Appendix 3 Appendix 5 Appendix 4	Page No.:	Page 17 Page 4 Page 2 Page 24-25 Page 6
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Coal Fired Thermal Generation		

PREAMBLE TO IR (IF ANY):

The Submission acknowledges that by virtue of Bill 15 coal-fired generation can no longer be used to support exports and is thereby appropriately assigned only to Domestic load. However, to avoid complexity with only minimal RCC impact Manitoba Hydro is proposing to include these costs in the generation pool to be allocated to both Domestic and Dependable exports.

QUESTION:

a) Please indicate what the impact would be on both Net Export Revenue and the RCC ratios if coal-fired generation was assigned only to Domestic load.

RATIONALE FOR QUESTION:

To understand the impact of Manitoba Hydro's proposed COSS treatment of coal-fired generation.

RESPONSE:

The allocation of the cost of Coal Generation among the domestic classes increases Net Export Revenue by $4.3 million, and impacts domestic class RCC ratios by 0.1% or less. Please see the attached RCC summary.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014
Revenue Cost Coverage Analysis
Model of Coalition/MH I-63
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Cost less NER	Change Cost less NER	Change in RCC	Change in NER
Residential	630,716	588,630	41,012	629,642	99.8%	589,704	(330.3)	0.0%	
General Service - Small Non Demand	132,791	135,035	8,394	143,428	108.0%	124,398	(50.4)	0.0%	
General Service - Small Demand	138,613	136,080	8,749	144,829	104.5%	129,864	11.2	0.0%	
General Service - Medium	200,770	186,797	12,771	199,568	99.4%	187,999	46.3	0.0%	
General Service - Large 0 - 30kV	100,037	84,956	6,348	91,304	91.3%	93,689	40.8	0.0%	
General Service - Large 30-100kV*	61,851	57,808	3,991	61,799	99.9%	57,860	55.0	-0.1%	
General Service - Large >100kV*	205,408	189,258	13,126	202,383	98.5%	192,283	259.3	-0.1%	
*Includes Curtailment Customers									
SEP	968	826	-	826	85.4%	968	-	0.0%	
Area & Roadway Lighting	22,012	21,630	439	22,069	100.3%	21,573	(4.3)	0.1%	
Total General Consumers	1,493,166	1,401,019	94,830	1,495,849	100.2%	1,398,336	27.7	0.0%	
Diesel	9,948	6,612	654	7,266	73.0%	9,294	(27.7)	0.2%	
Export	249,750	345,233	(95,484)	249,750	100.0%				4,320.2
Total System	1,752,864	1,752,864	-	1,752,864	100.0%				

Section:	Submission Appendix 3 Appendix 3.1 Appendix 5 Appendix 4 PCOSS14-Amended – Model	**Page No.:**	Page 17 Page 2 Page 11 Page 25 Page 6 Allocated Costs Tab
Topic:	Classification/Allocation		
Subtopic:	Generation		
Issue:	Trading Desk and MISO/MAPP Fees		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that in PCOSS14 there are $11.8 M in operating costs and $1.2 M in depreciation costs associated with Trading Desk.

b) Please indicate what the $1.2 M in depreciation costs is related to and why, if there are depreciation costs attributable to the Trading Desk there are no Interest costs?

c) Does the $11.8 M in operating costs include any assignment of operating costs associated with MH's corporate business units that support all activities of the Corporation such as President & CEO, Human Resources & Corporate Services and Corporate Relations?

d) Please explain why Manitoba Hydro has abandoned its earlier approach (per Appendix 3.1) of directly assigning to exports the portion of these costs that can be directly attributed to exports.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's proposed treatment of Trading Desk costs and MISO/MAPP fees.

RESPONSE:

a) Confirmed.

b) The $1.2 million of depreciation costs related to common, administrative and general costs that are assessed to the line activities based on labour charges within SAP. Interest costs are functionalized based on rate base in the Cost of Service Study and are only broken down to the functional level.

c) The $11.8 million includes the allocation of costs related to common, administrative and general costs that are assessed to the line activities based on labour charges within SAP.

d) Please see the response to COALITION/MH I-61a-c.

Section:	Appendix 3 PCOSS14-Amended (filed With COSS model) Appendix 3.1	**Page No.:**	Page 8 (Schedule E1) Page 33 (Schedule E4) Page 64 (Schedule E1) Page 68 (Schedule E4)
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Domestic Lines		

PREAMBLE TO IR (IF ANY):

Although it does not appear to be documented in the text that explains the COSS methodology (PCOSS14 or PCOSS14-Amended), a portion of Transmission Operating costs is separated out and allocated to Domestic and Exports (including Opportunity exports) using the 2CP allocation factor.

QUESTION:

a) Appendix 3 (Schedule E1) shows $4,071 k in Transmission Operating costs being allocated using the D13 Allocation Table. Please explain what these costs are for.

b) Please explain why, in PCOSS14-Amended, these costs were separated from the balance of Transmission costs and allocated to Domestic customers and Exports (including Opportunity exports).

c) Appendix 3.1 (Schedule E1) shows $2,375 k being allocated using the D13 Allocation Table in PCOSS14. Please explain the change in costs and how it relates the changes in methodology implemented in PCOSS14-Amended.

d) In Appendix 3.1 the D13 Allocation Table includes only Domestic customers whereas in Appendix 3 the D13 Allocation Table also includes all Exports. Please explain the reason for the change and how it relates to the changes in methodology implemented in PCOSS14-Amended.

RATIONALE FOR QUESTION:

To understand the proposed allocation of Transmission costs.

RESPONSE:

a) The $4.071 million cost represents the MISO fees that are allocated between domestic and export customers in PCOSS14-Amended.

b) The MISO fees were segregated in PCOSS14-Amended to allow a share to be allocated to Opportunity sales, which do not receive an allocation of the other Transmission costs.

c) The $2.375 million represents the 58% of MISO fees that were not considered export-related in PCOSS14. The costs were segregated to ensure an additional share would not be allocated to export sales, who were previously were directly assigned the other $1.696 million of the fees.

   For further discussion please see Manitoba Hydro’s response to COALITION/MH I-61a-c.

d) The D13 allocation table has been used to accomplish two different goals in PCOSS14 versus PCOSS14-Amended. In PCOSS14, the allocator used does not include any exports as the costs to be allocated included only the domestic-related portion of MISO fees. In PCOSS14-Amended the demand allocator includes all exports to ensure that Domestic, Dependable and Opportunity are all assigned a share of the $4.071 million of MISO fees.

   For further discussion, please see Manitoba Hydro’s response to COALITION/MH I-61a-c.

Section:	Submission Appendix 3.1 PCOSS14-Amended (filed With COSS model)	Page No.:	Page 11 Pages 48 & 68-69 Pages 33-34 (Schedules E4 & E5)
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Determination of 2CP Allocator		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Appendix 3.1 (page 48) indicates that the load research data used to determine the 2CP allocator was based on a single year's results (2011/12) due to a correction in the definition of peak hours. Please explain what this was and why it meant that the data available was limited to that for 2011/12.

b) As part of the review of its COSS methodology did Manitoba Hydro review the appropriateness of using the top 50 hours in each season to determine the CP allocator (e.g. was it still appropriate to include both seasons, was 50 hours still the appropriate number)? If yes, please provide the analysis supporting the continued use of the current definition.

RATIONALE FOR QUESTION:

To understand the proposed allocation of Transmission costs.

RESPONSE:

a) Please see the response to PUB/MH I-5.

b) Please see the response to MIPUG/MH I-7f.

Section:	Submission Appendix 3.1 PCOSS14-Amended (filed With COSS model)	Page No.:	Page 11 Pages 48 & 68-69 Pages 33-34 (Schedules E4 & E5)
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Determination of 2CP Allocator		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) If not, please provide in descending order (in graph/chart form) the values for the system peak (domestic plus export load) in the top 100 hours in each of season.

RATIONALE FOR QUESTION:

To understand the proposed allocation of Transmission costs.

RESPONSE:

Please find attached two tables listing the Top 100 generation hours (in descending order) for each of the 2011/2012 Load Research winter and summer peak periods referenced in PCOSS14-Amended Schedule D1.

Load Research Results 2011/2012
Top 100 Total Generation and Import Peaks
During Summer Peak Hours (June, July and August; 06:00 to 22:00)

Date Time	kW	Date Time	kW	Date Time	kW	Date Time	kW
2011-07-21 15:00	4,962,924	2011-06-30 13:00	4,847,979	2011-06-30 16:00	4,774,308	2011-07-15 14:00	4,741,303
2011-07-20 17:00	4,953,215	2011-07-18 18:00	4,842,387	2011-07-18 19:00	4,770,633	2011-07-28 15:00	4,738,376
2011-07-21 19:00	4,949,806	2011-07-18 17:00	4,840,233	2011-06-29 16:00	4,765,960	2011-07-04 12:00	4,735,646
2011-07-20 16:00	4,943,703	2011-06-29 20:00	4,836,660	2011-06-29 15:00	4,764,309	2011-07-19 17:00	4,735,552
2011-07-21 16:00	4,925,747	2011-07-13 14:00	4,835,667	2011-07-13 19:00	4,764,082	2011-07-05 16:00	4,734,252
2011-07-21 14:00	4,907,351	2011-07-20 19:00	4,834,738	2011-07-18 16:00	4,762,399	2011-07-10 21:00	4,732,819
2011-07-21 18:00	4,903,661	2011-06-29 17:00	4,821,251	2011-06-17 12:00	4,760,854	2011-06-30 14:00	4,732,467
2011-07-13 16:00	4,900,783	2011-07-20 22:00	4,818,827	2011-07-13 20:00	4,759,560	2011-07-11 20:00	4,731,265
2011-07-20 20:00	4,895,871	2011-07-18 21:00	4,813,143	2011-07-04 15:00	4,759,171	2011-06-29 22:00	4,728,292
2011-07-20 21:00	4,889,438	2011-07-18 14:00	4,809,000	2011-07-04 14:00	4,753,570	2011-06-30 12:00	4,726,127
2011-07-21 11:00	4,888,433	2011-07-19 19:00	4,807,766	2011-08-16 17:00	4,752,553	2011-07-30 20:00	4,725,644
2011-07-20 13:00	4,887,368	2011-07-18 13:00	4,806,000	2011-07-21 21:00	4,751,880	2011-08-16 18:00	4,723,836
2011-06-29 19:00	4,885,921	2011-07-18 15:00	4,798,705	2011-07-02 19:00	4,751,779	2011-07-27 14:00	4,722,458
2011-07-21 17:00	4,885,119	2011-07-20 12:00	4,793,792	2011-07-26 21:00	4,751,053	2011-08-03 18:00	4,721,732
2011-06-29 18:00	4,885,044	2011-08-16 14:00	4,791,723	2011-07-11 16:00	4,750,970	2011-07-14 9:00	4,721,631
2011-07-21 13:00	4,877,415	2011-07-13 13:00	4,789,873	2011-06-30 15:00	4,750,503	2011-07-12 11:00	4,720,874
2011-07-20 15:00	4,877,157	2011-08-03 15:00	4,789,383	2011-07-26 22:00	4,749,976	2011-07-06 12:00	4,720,609
2011-07-20 18:00	4,872,186	2011-07-19 18:00	4,786,782	2011-07-04 11:00	4,748,733	2011-08-03 17:00	4,719,832
2011-07-13 17:00	4,870,952	2011-07-04 18:00	4,786,217	2011-07-04 19:00	4,746,817	2011-08-16 16:00	4,719,051
2011-07-21 12:00	4,860,753	2011-08-02 18:00	4,783,895	2011-07-10 17:00	4,745,769	2011-07-12 12:00	4,717,198
2011-07-20 14:00	4,859,693	2011-07-21 10:00	4,782,916	2011-07-06 11:00	4,745,364	2011-07-27 20:00	4,716,748
2011-07-13 15:00	4,858,414	2011-06-30 11:00	4,779,988	2011-07-28 14:00	4,744,272	2011-08-02 19:00	4,714,905
2011-07-13 18:00	4,854,034	2011-08-16 15:00	4,775,903	2011-07-11 19:00	4,743,393	2011-07-14 19:00	4,714,591
2011-07-13 12:00	4,849,493	2011-06-29 21:00	4,774,628	2011-07-09 21:00	4,741,684	2011-06-30 17:00	4,714,196
2011-07-21 20:00	4,848,212	2011-07-18 20:00	4,774,539	2011-07-18 22:00	4,741,328	2011-07-08 15:00	4,712,010

Load Research Results 2011/2012
Top 100 Total Generation and Import Peaks
During Winter Peak Hours (December, January and February; 06:00 to 22:00)

Date Time	kW		Date Time	kW		Date Time	kW		Date Time	kW
2012-01-11 14:00	4,937,215		2012-01-19 19:00	4,809,357		2011-12-08 20:00	4,753,954		2012-01-29 19:00	4,725,248
2012-01-11 13:00	4,924,469		2012-01-05 18:00	4,809,181		2012-01-19 18:00	4,753,369		2012-01-18 8:00	4,724,459
2012-01-11 15:00	4,910,944		2012-01-12 10:00	4,800,221		2012-01-19 8:00	4,752,533		2012-01-05 19:00	4,724,082
2012-01-18 19:00	4,908,946		2011-12-08 17:00	4,797,786		2012-01-03 7:00	4,751,860		2012-01-10 17:00	4,723,003
2012-01-11 16:00	4,906,604		2012-01-06 18:00	4,797,555		2012-02-09 20:00	4,748,957		2012-01-16 21:00	4,719,634
2012-01-18 21:00	4,902,384		2012-01-19 21:00	4,795,276		2012-01-12 12:00	4,748,919		2012-01-25 20:00	4,718,731
2012-02-09 18:00	4,886,393		2012-01-11 21:00	4,792,830		2012-01-21 13:00	4,748,056		2012-01-18 14:00	4,718,495
2012-01-18 20:00	4,880,712		2012-01-11 10:00	4,791,709		2012-01-06 19:00	4,747,080		2012-01-10 19:00	4,718,196
2012-01-11 9:00	4,871,986		2011-12-08 12:00	4,791,328		2012-01-19 20:00	4,747,044		2012-01-08 19:00	4,716,127
2012-01-12 9:00	4,871,846		2012-02-09 19:00	4,789,217		2011-12-08 15:00	4,746,992		2012-01-18 13:00	4,716,127
2012-01-03 19:00	4,863,251		2012-01-10 18:00	4,789,074		2012-01-19 22:00	4,743,196		2012-01-03 10:00	4,715,622
2012-01-11 12:00	4,860,518		2012-01-20 9:00	4,788,204		2011-12-06 17:00	4,741,813		2011-12-08 16:00	4,712,391
2012-01-06 17:00	4,857,679		2012-01-18 10:00	4,785,371		2011-12-02 9:00	4,740,189		2012-01-04 10:00	4,712,215
2012-01-11 18:00	4,851,275		2012-02-10 19:00	4,783,961		2012-01-16 9:00	4,739,044		2011-12-08 14:00	4,711,394
2012-01-11 17:00	4,846,272		2012-01-03 18:00	4,779,536		2012-01-21 18:00	4,738,701		2011-12-06 18:00	4,709,737
2012-01-11 8:00	4,839,721		2011-12-28 10:00	4,775,578		2011-12-08 13:00	4,735,147		2011-12-07 19:00	4,709,486
2011-12-08 18:00	4,838,358		2011-12-02 17:00	4,771,524		2012-01-02 19:00	4,734,216		2012-01-12 14:00	4,709,147
2012-01-19 9:00	4,835,169		2012-01-17 20:00	4,768,073		2012-01-18 15:00	4,733,340		2012-01-21 19:00	4,708,806
2012-01-11 11:00	4,832,641		2012-01-19 11:00	4,766,402		2012-01-19 17:00	4,731,180		2011-12-19 21:00	4,707,981
2012-01-19 10:00	4,825,047		2012-01-12 11:00	4,765,900		2012-02-08 19:00	4,731,081		2012-02-09 11:00	4,705,579
2012-01-11 20:00	4,820,417		2012-01-18 12:00	4,760,845		2012-01-18 17:00	4,729,094		2012-01-19 12:00	4,705,275
2012-01-18 18:00	4,819,902		2012-01-16 8:00	4,760,239		2011-12-28 11:00	4,727,805		2011-12-06 16:00	4,704,226
2012-01-11 19:00	4,813,286		2012-02-09 21:00	4,758,994		2012-01-16 20:00	4,727,411		2012-01-20 8:00	4,704,083
2012-01-18 22:00	4,812,100		2012-01-07 18:00	4,754,733		2012-01-16 17:00	4,726,210		2011-12-19 20:00	4,701,966
2012-01-18 11:00	4,809,673		2012-01-16 18:00	4,754,092		2012-01-25 19:00	4,726,036		2012-01-12 13:00	4,700,926

Section:	Submission	**Page No.:**	Page 21
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Interconnections - Definition		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the proposed treatment of interconnections in PCOSS14- Amended applies only to US Interconnections.

b) Does Manitoba Hydro own interconnection facilities with other provinces and, if so, why weren't they assigned the same COSS treatment as the US Interconnections?

c) In the context of IFF12, what was the forecast 2013/14 net book value, depreciation cost and operating costs associated with interconnections with Canadian provinces?

RATIONALE FOR QUESTION:

To understand the proposed treatment of Transmission-Interconnection costs.

RESPONSE:

a) Confirmed.

b) Yes. Manitoba Hydro has interconnections with Ontario and Saskatchewan. These interties continue to be classified as demand allocated on the basis of 2CP. US Interconnections have been sub-functionalized in COS, classified and allocated on the basis of weighted energy as discussed further in COALITION/MH I-68a-c. Primarily, distinction in treatment between the Provincial and US interconnections is drawn considering:

- US Interconnections provide an important source of economic supply during off-peak hours when there is ample excess capacity in MISO;
- US Interconnections provide load diversity benefits that are not found in connections with Ontario or Saskatchewan;
- Interconnections with Ontario and Saskatchewan do not provide significant firm import capability; and
- Materiality and complexity. The differences obtained with attempting to sub-functionalize the Ontario and Saskatchewan interties do not appear significant enough to merit the additional complexity.

c)

Circuit Name	Description	PCOSS14 2013/14 NBV	PCOSS14 Interest	PCOSS14 Depreciation	PCOSS14 Operating*
R7B	Reston-Sask. 230 kV AC	384,490	19,576	14,920	-
R25Y	Roblin S-Yorkton Sk.230 kV AC	1,131,799	57,391	33,332	-
P52E	Rall's Isl.- E.B. Campbell 230 kV AC	771,638	39,761	73,243	248,685
SK1	Seven Sisters-Ontario 115 kV AC	5,573,152	283,493	204,364	-
K21/22W	Kenora-Whiteshell 230 kV AC	6,538,404	332,379	230,099	-

*Operating costs associated with these interties are not explicitly forecasted in most cases.

Section:	Submission Appendix 1 Appendix 2 PUB-MFR5	Page No.:	Page 21 Pages 6-7 Pages 14-16 Page 43
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Interconnections - Definition		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Has the definition of what facilities are considered "Interconnection" changed from that used in the 2005 COSS review? If so, what is the change?

b) In the 2005 COSS Review Manitoba Hydro had initially proposed that Interconnections be classified as energy-related. However, in its subsequent Rebuttal evidence Manitoba Hydro indicated that, based on internal review, this position had changed and "it would be appropriate to classify the entire Transmission system as demand-related and allocate its costs on the basis of the 2CP factor" (see PUB-MFR5). Please outline both the considerations that led Manitoba Hydro to: i) adopt the position set out in the Rebuttal Evidence and ii) to subsequently revert to its initial 2005 position for purposes of the current Submission?

c) Why is a weighted energy allocator preferable to the simple energy-based allocator proposed in the 2005 COSS Review?

RATIONALE FOR QUESTION:

To understand the proposed allocation of Transmission - Interconnection costs.

RESPONSE:

a) Yes. In the 2005/06 Cost of Service Methodology Review, the definition of interconnection lines was provided in PUB/MH I-23 as:

"Transmission lines (and selected stations) that are deemed as interconnection lines have been separately identified in Manitoba Hydro's financial report system SAP. The determination is based on whether the transmission line (and the primary function of associated station) crossed the provincial boundaries to the east, south and west."

On this basis, in that Submission all transmission lines (including interconnections with Saskatchewan and Ontario) that crossed the Manitoba border including six substations were included in the definition.

As part of the current COS review undertaken by Manitoba Hydro, CA has also recommended to sub-functionalize interties and classify and allocate on the basis of the weighted energy allocator but has limited this treatment to US Interconnections.

b) A previous review of Manitoba Hydro's Cost of Service prepared by NERA Consulting in 2004 entitled "Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies" also recognized the primary role of interconnections is to move energy. NERA recommended that Manitoba Hydro use a line-specific approach for transmission that "attempts to make a more precise distinction between transmission investment related to serving peak loads and that justified because it reduces energy costs or facilitates energy exports." Their recommendation was based on the fact that "the line-specific approach recognizes the multiple roles of various parts of the transmission system and explicitly reflects the role of Manitoba Hydro's transmission system in the regional market."

As part of the Cost of Service Methodology Review in 2006, Manitoba Hydro accepted NERA's recommendation that the costs associated with the transmission tie-lines be allocated on the basis of annual energy, while the remaining AC network transmission facilities be allocated on demand using a 2CP allocator. During that hearing, Manitoba Hydro abandoned this approach. Manitoba Hydro continued to see merit in the energy-related allocation methodology, however due to the additional complexity that some transmission lines were not easily sub-functionalized (some of the interties also have tapoffs which provide AC facilities that support general peak load requirements of the customers/communities interconnected) and the relatively minor impact on results at the time, it was determined that it would continue to classify interconnections as demand-related.

The CA recommendation is conceptually consistent with that recommended by NERA; principally that distinction should be drawn between transmission investment related to serving peak load and transmission that is related to moving energy. The CA recommendation, however, limits the allocation methodology to Manitoba Hydro's US interconnections. This provides a workable solution to that provided by NERA in its 2004 Report that avoids complex analysis attempting to quantify the portion of the transmission line that serves peak demand vs. energy (or a combination of). And it recognizes the significance of the import capability related to the US Interconnections. These US interconnections allow MH access to a substantial energy market to mitigate vulnerability to power outage events, on a large scale that would likely occur with a strong random component (CA, page 16).

c) The CA Report (August 2015, page 16) states:

"Supply side contingency events, which network reinforcement investments are designed to minimize, potentially impose large power outage costs on retail customers and will likely occur with a strong random component. Weighted energy based allocation accurately captures the time pattern of foregone value of the consumption of electricity (outage costs) as a consequence to supply side events. Thus, the costs of Manitoba Hydro's interface facilities should be allocated according to weighted energy. We recommend that MH use weighted energy in lieu of energy without marginal cost-based price weights, because empirical evidence suggests (but does not prove) that, day by day, electricity consumption during peak load hours is more highly valued – i.e., outage costs are higher – than consumption during off-peak hours."

Manitoba Hydro accepts the advice provided by CA that considers the interconnections as a resource used to serve load reliably - not just providing energy over a year, but energy at every hour of the year. Use of Weighted Energy captures the price differential between these hours (the differential of which implicitly captures demand, recognizing it is also a valid cost driver) thus recognizing the cost of serving load in each hour.

Section:	2005 COSS Review, PUB/MH I-29 Appendix 4	**Page No.:**	Page 10
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Classification of Distribution Facilities		

PREAMBLE TO IR (IF ANY):

At the time of the 2005 COSS review Manitoba Hydro filed a study undertaken in 1990 to support its classification of Distribution Plant costs.

In response to Christensen Associates' 2012 Report Manitoba Hydro stated: "MH will update the split of distribution costs into demand- and customer-related components as resources allow. MH currently classifies distribution pole and wires as 60% Demand and 40% Customer related which is comparable to that seen at other utilities. The current classification of line transformers as demand-related is not uncommon in the industry".

QUESTION:

a) Are the references to current industry practices made in response to Christensen Associates' recommendation based on a more recent assessment of industry practice than that provided during the 2005 COSS Review? If yes, please provide. If not, please re-file the study provided during the 2005 COSS review.

RATIONALE FOR QUESTION:

To understand the proposed classification of Distribution Plant costs.

RESPONSE:

Yes, the reference to current industry practices was based on the advice and experience of CA at the time of the preparation of their Report in 2012 (pages 17-19).

Section:	Appendix 4	Page No.:	Page 10
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Classification of Distribution Facilities		

PREAMBLE TO IR (IF ANY):

In response to Christensen Associates' 2012 Report Manitoba Hydro stated:

"MH will update the split of distribution costs into demand- and customer-related components as resources allow. …. Conducting studies as recommended requires a significant volume of data, effort and cost and may not yield results materially different than the current ratio"

QUESTION:

a) Please indicate the impact on the rate class RCC ratios if transformers were classified as 50% Demand and 50% Customer.

b) Please indicate the impact on the rate class RCC ratios if poles and wires were classified as 40% Demand and 60% Customer.

RATIONALE FOR QUESTION:

To understand the impact of a change in the classification of Distribution Plant costs.

RESPONSE:

a) Please see the schedules below.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014
Revenue Cost Coverage Analysis
Model of Coalition/MH I-70a
SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Cost less NER	Change Cost less NER	Change in RCC	Change in NER
Residential	630,482	588,630	39,259	627,889	99.6%	591,223	1,189.2	-0.2%	
General Service - Small Non Demand	132,038	135,035	7,990	143,025	108.3%	124,047	(400.7)	0.3%	
General Service - Small Demand	136,761	136,080	8,261	144,341	105.5%	128,499	(1,353.5)	1.0%	
General Service - Medium	197,851	186,797	12,046	198,843	100.5%	185,805	(2,147.2)	1.1%	
General Service - Large 0 - 30kV	99,712	84,956	6,058	91,014	91.3%	93,654	5.2	0.0%	
General Service - Large 30-100kV*	61,613	57,808	3,807	61,614	100.0%	57,806	0.7	0.0%	
General Service - Large >100kV*	204,538	189,258	12,514	201,772	98.6%	192,024	0.3	0.0%	
*Includes Curtailment Customers									
SEP	968	826	-	826	85.4%	968	0.6	0.0%	
Area & Roadway Lighting	24,870	21,630	600	22,230	89.4%	24,269	2,691.9	-10.8%	
Total General Consumers	1,488,831	1,401,019	90,536	1,491,555	100.2%	1,398,295	(13.6)	0.0%	
Diesel	9,963	6,612	627	7,239	72.7%	9,336	13.6	-0.1%	
Export	254,070	345,233	(91,163)	254,070	100.0%				-
Total System	1,752,864	1,752,864	-	1,752,864	100.0%				

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Customer, Demand, Energy Cost Analysis
Model of Coalition/MH I-70a
SUMMARY

	CUSTOMER			DEMAND					ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA		Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	129,564	486,987	22.17	171,286	0%	n/a	n/a		290,373	7,404,453	6.23	**
GS Small - Non Demand	25,024	53,778	38.78	32,415	0%	n/a	n/a		66,608	1,605,511	6.17	**
GS Small - Demand	8,398	12,492	56.02	37,631	38%	2,390	5.97		82,469	2,047,715	5.17	
General Service - Medium	7,183	1,974	303.25	53,773	87%	7,302	6.44		124,849	3,174,662	4.15	
General Service - Large <30kV	3,601	288	n/a	24,176	100%	4,042	6.87	*	65,877	1,702,481	3.87	
General Service - Large 30-100kV	2,486	40	n/a	9,030	100%	2,894	3.98	*	46,290	1,327,210	3.49	
General Service - Large >100kV	2,296	16	n/a	19,704	100%	8,409	2.62	*	170,023	4,903,742	3.47	
SEP	326	29	937.56	132	0%	n/a	n/a		509	26,500	2.42	**
Area & Roadway Lighting	19,367	155,024	10.41	2,010	0%	n/a	n/a		2,893	100,487	4.88	**
Total General Consumers	198,245	710,628		350,158		25,038			849,892	22,292,761		
Diesel	220	755	24.28	330	0%	n/a	n/a		8,771	13,754	66.17	**
Export	n/a	n/a	n/a	21,172	0%	n/a	n/a		232,898	9,013,000	2.82	***
Total System	198,465	711,383		371,660		25,038			1,091,560	31,319,515		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Functional Breakdown
Model of Coalition/MH I-70a
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	591,223	289,091	48.9%	46,667	7.9%	31,007	5.2%	66,675	11.3%	157,782	26.7%
General Service - Small Non Demand	124,047	66,330	53.5%	9,967	8.0%	5,597	4.5%	16,944	13.7%	25,209	20.3%
General Service - Small Demand	128,499	82,121	63.9%	11,798	9.2%	6,448	5.0%	4,049	3.2%	24,083	18.7%
General Service - Medium	185,805	124,313	66.9%	18,111	9.7%	8,915	4.8%	6,162	3.3%	28,304	15.2%
General Service - Large <30kV	93,654	65,595	70.0%	9,362	10.0%	4,457	4.8%	3,380	3.6%	10,860	11.6%
General Service - Large 30-100kV	57,806	46,085	79.7%	5,831	10.1%	3,403	5.9%	2,419	4.2%	67	0.1%
General Service - Large >100kV	192,024	169,280	88.2%	20,447	10.6%	0	0.0%	2,268	1.2%	28	0.0%
SEP	968	509	52.6%	132	13.7%	0	0.0%	309	31.9%	17	1.8%
Area & Roadway Lighting	24,269	2,999	12.4%	321	1.3%	440	1.8%	534	2.2%	19,976	82.3%
Total General Consumers	1,398,295	846,324	60.5%	122,635	8.8%	60,268	4.3%	102,741	7.3%	266,327	19.0%
Diesel	9,321	8,771	94.1%	0	0.0%	0	0.0%	0	0.0%	550	5.9%
Export	254,070	232,148	91.4%	21,922	8.6%	0	0.0%	0	0.0%	0	0.0%
Total System	1,661,686	1,087,243	65.4%	144,557	8.7%	60,268	3.6%	102,741	6.2%	266,877	16.1%

b) Please see the schedules below.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014
Revenue Cost Coverage Analysis
Model of Coalition/MH I-70b
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Cost less NER	Change Cost less NER	Change in RCC	Change in NER
Residential	637,828	588,630	39,721	628,351	98.5%	598,107	8,073.1	-1.3%	
General Service - Small Non Demand	132,316	135,035	8,008	143,043	108.1%	124,308	(140.1)	0.1%	
General Service - Small Demand	135,561	136,080	8,186	144,266	106.4%	127,375	(2,477.6)	1.9%	
General Service - Medium	195,715	186,797	11,911	198,708	101.5%	183,804	(4,148.4)	2.1%	
General Service - Large 0 - 30kV	98,133	84,956	5,959	90,915	92.6%	92,174	(1,474.9)	1.3%	
General Service - Large 30-100kV*	61,612	57,808	3,807	61,614	100.0%	57,805	(0.0)	0.0%	
General Service - Large >100kV*	204,538	189,258	12,514	201,772	98.6%	192,023	(0.0)	0.0%	
*Includes Curtailment Customers									
SEP	969	826	-	826	85.3%	969	1.5	-0.1%	
Area & Roadway Lighting	22,174	21,630	431	22,060	99.5%	21,744	166.4	-0.7%	
Total General Consumers	1,488,846	1,401,019	90,537	1,491,556	100.2%	1,398,309	0.0	0.0%	
Diesel	9,948	6,612	626	7,238	72.8%	9,322	(0.0)	0.0%	
Export	254,070	345,233	(91,163)	254,070	100.0%				-
Total System	1,752,864	1,752,864	-	1,752,864	100.0%				

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Customer, Demand, Energy Cost Analysis
Model of Coalition/MH I-70b
SUMMARY

	CUSTOMER			DEMAND				ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	143,609	486,987	24.57	164,125	0%	n/a	n/a	290,373	7,404,453	6.14	**
GS Small - Non Demand	26,577	53,778	41.18	31,122	0%	n/a	n/a	66,608	1,605,511	6.09	**
GS Small - Demand	8,763	12,492	58.46	36,142	38%	2,390	5.73	82,469	2,047,715	5.12	
General Service - Medium	7,241	1,974	305.68	51,714	87%	7,302	6.19	124,849	3,174,662	4.14	
General Service - Large <30kV	3,605	288	n/a	22,692	100%	4,042	6.51 *	65,877	1,702,481	3.87	
General Service - Large 30-100kV	2,485	40	n/a	9,030	100%	2,894	3.98 *	46,290	1,327,210	3.49	
General Service - Large >100kV	2,296	16	n/a	19,704	100%	8,409	2.62 *	170,023	4,903,742	3.47	
SEP	327	29	940.15	132	0%	n/a	n/a	509	26,500	2.42	**
Area & Roadway Lighting	16,939	155,024	9.11	1,912	0%	n/a	n/a	2,893	100,487	4.78	**
Total General Consumers	211,842	710,628		336,575		25,038		849,892	22,292,761		
Diesel	220	755	24.28	330	0%	n/a	n/a	8,772	13,754	66.18	**
Export	n/a	n/a	n/a	21,172	0%	n/a	n/a	232,898	9,013,000	2.82	***
Total System	212,062	711,383		358,077		25,038		1,091,561	31,319,515		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Functional Breakdown
Model of Coalition/MH I-70b
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	598,107	289,091	48.3%	46,667	7.8%	31,007	5.2%	66,675	11.1%	164,666	27.5%
General Service - Small Non Demand	124,308	66,330	53.4%	9,967	8.0%	5,597	4.5%	16,944	13.6%	25,470	20.5%
General Service - Small Demand	127,375	82,121	64.5%	11,798	9.3%	6,448	5.1%	4,049	3.2%	22,959	18.0%
General Service - Medium	183,804	124,313	67.6%	18,111	9.9%	8,915	4.9%	6,162	3.4%	26,303	14.3%
General Service - Large <30kV	92,174	65,595	71.2%	9,362	10.2%	4,457	4.8%	3,380	3.7%	9,380	10.2%
General Service - Large 30-100kV	57,805	46,085	79.7%	5,831	10.1%	3,403	5.9%	2,419	4.2%	67	0.1%
General Service - Large >100kV	192,023	169,280	88.2%	20,447	10.6%	0	0.0%	2,268	1.2%	28	0.0%
SEP	969	509	52.6%	132	13.7%	0	0.0%	309	31.9%	18	1.9%
Area & Roadway Lighting	21,744	3,013	13.9%	322	1.5%	442	2.0%	537	2.5%	17,430	80.2%
Total General Consumers	1,398,309	846,338	60.5%	122,637	8.8%	60,270	4.3%	102,743	7.3%	266,320	19.0%
Diesel	9,322	8,772	94.1%	0	0.0%	0	0.0%	0	0.0%	550	5.9%
Export	254,070	232,148	91.4%	21,922	8.6%	0	0.0%	0	0.0%	0	0.0%
Total System	1,661,701	1,087,258	65.4%	144,559	8.7%	60,270	3.6%	102,743	6.2%	266,870	16.1%

Section:	Appendix 4 Appendix 3.1	Page No.:	Pages 11-12 Page 49
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Distribution Lines and Poles – Secondary Adjustment		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the 70/30 split refers to the cost of distribution poles and lines considered to be related to primary versus secondary facilities.

b) Please confirm that Manitoba Hydro's adjustment to the allocator for distribution lines involves reducing the allocation factor (i.e. the 1NCP load and number of customers) for GSL 0-30 kV by 30%.

c) Please confirm that reducing the allocation factors for GSL 0-30 kV by 30% does not result in precisely the same allocation of costs to rate classes as would result if one were to split the costs into 70% primary and 30% secondary and then allocate the first cost pool to the rate classes using primary facilities and the second cost pool to just the rate classes using secondary facilities. If not confirmed, please demonstrate that the results are equivalent.

RATIONALE FOR QUESTION:

To understand the effect of the Secondary Adjustment made to the allocator for Distribution Poles & Wires.

RESPONSE:

a) Confirmed.

b) Confirmed.

c) Confirmed, the approach used by Manitoba Hydro yields very similar but not precisely the same allocation of costs that would result from allocating the costs after first sub-functionalizing into primary and secondary Distribution. Please see Manitoba Hydro's response to COALITION/MH I-50f for further discussion for the approach used by Manitoba Hydro.

Section:	Appendix 4	**Page No.:**	Page 11
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Treatment of GSL 0-30 kV Rate Class		

PREAMBLE TO IR (IF ANY):

In Appendix 4 Manitoba Hydro indicated that it "accepts the recommendation that GSL 0-30 kV customers served from dedicated MH owned substations should be excluded from the allocation of distribution lines costs ….The current treatment results in a slight overstatement in the cost to serve the GSL 0-30 kV subclass that will be addressed in the next study".

QUESTION:

a) Has Manitoba Hydro addressed this issue in either PCOSS14 or PCOSS14- Amended? If so, precisely how? If not, why not?

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's follow-up to Christensen Associates' recommendations.

RESPONSE:

Yes. Manitoba Hydro considered the issue further in a review undertaken subsequent to the CA Report in 2012. Manitoba Hydro identified two GSL 0-30 kV customers that were served from dedicated Manitoba Hydro owned substations. Manitoba Hydro did not consider it reasonable or feasible to create a new customer class for the two affected customers and adjusting the allocation of distribution line costs would have had a minimal impact on class RCC. Manitoba Hydro elected not to pursue any refinement to accommodate the recommendation in PCOSS14 (or PCOSS14-Amended).

Section:	Appendix 4 Appendix 3.2 Appendix 3.1 PCOSS14-Amended Model	**Page No.:**	Page 12 Page 8 C Tables Tab
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Treatment of ARL		

PREAMBLE TO IR (IF ANY):

In Appendix 4 Manitoba Hydro indicated that it "is appropriate to confirm that both the wattage threshold and the number of installed lamps per relay reflect the technologies and practices currently used for lighting installations, which may have changed since the factors were developed".

In Appendix 4 Manitoba Hydro also states it "has adopted the convention that 30% of poles and wires are related to secondary distribution and have excluded ARL from the allocation of the customer portion of the common secondary distribution system"

In the PCOSS14-Amended model (C Tables Tab) the following formula is used to calculate the customer count for ARL for allocating Poles and Wires costs: ROUND((((7529/6)+(121522/10))*C294),0) – where C294 = 58%

QUESTION:

a) Please confirm that in PCOSS14 and PCOSS-Amended, Manitoba Hydro is using the same assumptions regarding the number of fixtures per customer as described by Christensen Associates in Appendix 4.

b) Did Manitoba Hydro review the matter of the number of fixtures per relay and the wattage threshold used in making this determination as it indicated it would in Appendix 4? If so, please describe how the review was conducted and what the findings were.

c) With respect to the formula used to derive the ARL customer count for purposes of allocating Poles & Wires costs, please explain the basis for the 58% factor used.

d) With respect to the formula used to derive the ARL customer count for purposes of allocating Poles & Wires costs, the total number of fixtures used in the calculation appears to be 129,051 (7,529+121,522) whereas the total number of fixtures/customers in the class is 155,024 (per Schedule D5) – the difference being Sentinel Lights. Please explain why Sentinel Lights were excluded from the determination of the allocation factor.

e) Are all Sentinel Lights associated with customers also receiving service under another rate classification?

f) Are all Sentinel Lights associated with customers also receiving service under another rate classification connected on the customer side of customer's delivery point for its service under the associated rate classification?

g) Are all ARL customers served off Manitoba Hydro's secondary distribution system or do some of them provide their own transformation (similar to GSL 0- 30)?

h) If all ARL customers are served off the secondary system, please explain why it is appropriate to exclude ARL from the allocation of the customer portion of the common secondary distribution system.

RATIONALE FOR QUESTION:

To understand the treatment of the ARL class in the allocation of Poles and Wires costs.

RESPONSE:

a) Confirmed.

b) Manitoba Hydro has not reviewed the number of fixtures per relay since the response provided in Appendix 4 was prepared.

c) Area and Roadway Lighting is different than other rate classes in the way in which they tap and utilize common distribution plant. Generally street lights connect into the distribution system in the following manner:

Overhead Distribution

- Street lights are fed from the low side of a distribution transformer and are connected in a series of lights by a dedicated secondary wire with the lights being controlled through a relay. In this instance the dedicated secondary street light wire, the street light arm and luminaire utilize common poles and facilities.
- Street lights are fed individually by tapping a common secondary wire with each light being controlled by a photo electric cell. In this instance all common facilities are utilized.

Underground Distribution

- Street lights are fed from the low side of a distribution transformer and are connected in a series of lights by a dedicated underground secondary wire with the lights being controlled through a relay. In this instance, where service to other classes is from the rear of the lot line, either overhead or underground, the entire secondary system that services street lights is dedicated and the common secondary system is not utilized.
- Street lights are fed individually from the low side of a distribution transformer by a dedicated underground secondary wire with each light being controlled by a photo electric cell. In this instance, where service to other classes is from underground front street distribution, the street light wire shares a common trench with the common secondary wire.

The approach Manitoba Hydro has used in the allocation of the Customer portion of distribution pole and wires is a compromise considering the above factors and costs. Customer costs of the secondary distribution system have not been allocated to street lights since some lights will already include the cost of a dedicated secondary and since they are already allocated demand related costs associated with the secondary system. An adjustment is required to the customer count obtained though the use of lamp size and connection through a relay to reflect 58% of the original count. This percentage is based upon the customer/demand split of the distribution poles and wires and is calculated as follows:

- Investment and maintenance costs are 70% related to the primary voltage level and 30% to the secondary voltage level;

- Primary system costs are split 70% Demand and 30% Customer;
- Secondary system costs are split 50% Demand and 50% Customer.

The formula for deriving the Primary System's portion of the total customer-related portion of distribution poles and wires is:

$$\frac{A \times B}{(A \times B) + (C \times D)}$$

Where:
A = customer portion of primary = 30%
B = investment in primary = 70%
C = customer portion of secondary = 50%
D = investment in secondary = 30%

$$\frac{\text{Primary customer \%}}{\text{Total customer \%}} = \frac{0.30 \text{ X } 0.70}{(0.30 \text{ X } 0.70) + (0.50 \text{ X } 0.30)} = 58\%$$

d) Sentinel Lights are not allocated Customer-related share of Distribution Pole and Wires as this service is assumed to have been provided by the primary rate class.

e) Sentinel Lights are generally, but not necessarily, associated with a customer receiving service under another rate class. The exceptions would be few, but do exist.

f) Energy for Sentinel Lights connected on the load side of Manitoba Hydro's revenue meter will be billed under the associated customer's rate classification.

g) A&RL customers do not provide their own transformation.

h) Please see Manitoba Hydro's response to part d).

Section:	Appendix 3.1	**Page No.:**	Pages 81 - 83
Topic:	Classification/Allocation		
Subtopic:	Distribution Plant		
Issue:	Weightings for Services, Meters and Meter Maintenance		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) How were the weighting factors for each of Services, Meters and Meter Maintenance established and when were they last reviewed?

RATIONALE FOR QUESTION:

To understand the allocation of Distribution Plant costs.

RESPONSE:

Please see Manitoba Hydro's responses to PUB/MH I-57 and PUB/MH I-58.

Section:	Appendix 3.1 Appendix 3.2 Appendix 4 PCOSS14-Amended Model	Page No.:	Pages 74-78 Pages 5-7 Pages 12-13 C Tables Tab
Topic:	Classification/Allocation		
Subtopic:	Distribution Service		
Issue:	Customer Weighting Factors		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The response to Christensen Associates' June 2012 Report indicated that Manitoba Hydro was going to review and possibly update the weighting factors used for Billing (C11) and Collections (C12). Was a review of these weighting factors undertaken? If so please provide the results and indicate if it led to change in the weighting factors. If not, when were these two weighting factors established/last reviewed?

b) Please indicate when the weighting factors used for the other three allocators (C10, C13 and C14) were last reviewed.

c) Please explain why for Billing costs (C11) the weight applied to Water Heating is 0.0027 whereas the weight applied to Sentinel Lighting is 0.0006.

d) Appendix 4 indicates that Marketing R&D includes costs related to customer surveys and maintaining customer coding databases. Are the costs incurred by Manitoba Hydro in maintaining its data bases regarding the number of luminaires and associated connections attributed to the SRL rate class reflected in this sub- function? If yes, why is ARL excluded from the allocation? If no, where are the costs captured?

e) Please explain why for Marketing R&D costs (C13), the weighting applied to Water Heating is 0.1 whereas the weighting applied to Sentinel Lighting is zero.

f) Why are there no Electrical Inspection costs allocated to ARL?

g) Why are there no Distribution Services costs allocated to Diesel? Are all activities such as billing, collecting and customer service related to Diesel tracked and recorded separately?

RATIONALE FOR QUESTION:

To understand the allocation of Distribution Service costs.

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH I-57.

b) Please see Manitoba Hydro's response to PUB/MH I-57.

c) The weighting column was added to the electronic model for the current Cost of Service Review to allow stakeholders to test different weighting factors. Class weightings were back-calculated based on customer count to match the allocators shown in the model of PCOSS14-Amended. The weight indicated for Area & Roadway Lighting in the model is neither the Sentinel and Street Lighting weights, but a combination of the two weighting factors.

   Please see Manitoba Hydro's response to COW/MH I-3 for the derivation of the weighting factors for FRWH and Sentinel Lights.

d) No, the expenses incurred to track the number of luminaires for A&RL are included as part of Manitoba Hydro's Customer Billing costs which are allocated to all classes, as well as in the costs of the eGIS system which is allocated to all functions (and customers) as part of common, administrative and general costs.

e) Manitoba Hydro has historically used the convention that ten A&RL fixtures or ten FRWH accounts were equivalent to one customer for the purposes of Marketing R&D cost allocation. The ten:one ratio was considered a reasonable compromise to recognize that the classes should bear some responsibility for the Customer related costs, and an allocation on un-weighted fixtures/accounts would be unfairly burdensome for the classes.

In their 2012 review, Christensen Associates recommended that Manitoba Hydro not allocate any Marketing R&D costs to the A&RL class based on the type of costs included in the sub-function. On the basis of this advice as discussed in Appendix 4 (page 3), Manitoba Hydro has used a zero weight for A&RL since PCOSS13.

f) Electrical Inspection costs are incurred to inspect customer-owned plant related to the construction, installation, maintenance, repair, extension, alteration and use of electric wiring and related facilities using or intended to use electricity supplied by Manitoba Hydro.

Electrical inspection activity charges are categorized as either residential or commercial inspection costs in SAP. The Customer allocator used in the PCOSS prorates the relative residential share among Residential subclasses based on forecast customer count. The relative commercial share is prorated among GSS, SEP, GSM and GSL subclasses on the same basis. The combined allocator is used for total electrical inspection costs in the study.

Area and Roadway Lighting plant is owned by Manitoba Hydro and not subject to electrical inspections; therefore it is excluded from the allocator.

g) All customer service costs including billing and collections related to the Diesel rate zone are tracked separately and allocated directly to the Diesel class.

Section:	Appendix 4 Appendix 3.2 Schedule 3.1 2012/13 & 2013/14 GRA CAC/MH II-33 c) PUB Order 159/04	**Page No.:**	Page 7 Page 47 Pages 37-38 & 65 Page(ii)
Topic:	Net Export Revenue		
Subtopic:	Allocation		
Issue:	Determination of Allocation Factors		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that, except for those costs associated with Diesel, directly assigned costs were excluded from the costs used to allocate Net Export Revenues.

b) Please explain why these direct assignments were excluded from the costs allocated to each rate class that were used as the allocation base for Net Export Revenues.

c) With respect to Appendix 3.1 (Schedule C8, C9 & E1), how were capital contributions from 3rd parties (e.g. AANDC) treated in determining the value of the assets used to allocate interest to Diesel?

d) With respect to Appendix 3.1 (Schedules C8, C9 & E1), how were capital contributions to Diesel communities from Manitoba Hydro (as described in Order 159/04, page (ii), item #5) treated in determining the value of the assets used to allocate interest to Diesel?

e) With respect to Appendix 3.1 (Schedule E1), how was the amortization of these capital contributions treated in determining the depreciation costs attributed to Diesel?

f) It is noted that the resulting costs allocated to Diesel (per Schedule E1) are used as the allocation base for assigning Net Export Revenues to Diesel. Please describe how the determination of allocation base and, in particular the treatment of capital contributions as described in response to parts c) through e), is consistent with the Settlement Agreement.

RATIONALE FOR QUESTION:

To understand the allocation of Net Export Revenues to Diesel and the effect of the Settlement Agreement.

RESPONSE:

a) Confirmed.

b) The allocator used for Net Export Revenue excludes the costs of dedicated or end-use facilities that are directly assigned to customer classes, namely the costs related to DSM and Area and Roadway Lighting. DSM is generally related to facilities located on customer premise and beyond the point of delivery, while ARL costs are related to dedicated end-use facilities that would be considered beyond the point of delivery for most customer classes. The decision not to provide these costs with a NER offset ensures these facilities are not provided a benefit that is not reasonably attributable to other end use portion of load, such as refrigerators or stoves used by Residential or General Service classes.

Response to parts c) to e):

Please see Manitoba Hydro's response to COALITION/MH I-8a.

f) Manitoba Hydro is not able to disclose details of the tentative settlement agreement until such time as a fully executed copy has been provided by MKO or alternatively, the PUB orders Manitoba Hydro to produce the partially executed version in its possession.

That said, the treatment of allocating net export revenues on the basis of total cost to serve, which provides for an allocation to the Diesel communities, can be evaluated independent to the contractual provisions. Manitoba Hydro is of the view that this treatment is consistent with the intent of the Agreement.

Section:	PUB MFR18	Page No.:	Attachment
Topic:	Terms and Conditions of Service		
Subtopic:	Service Agreement		
Issue:	Payments Required		

PREAMBLE TO IR (IF ANY):

Section 15 (1) of the Electric Power Terms and Conditions of Supply Regulation states: "The user shall pay Manitoba Hydro for power supplied at the rates, and for a period of time, not less than the minimum term, as established by Manitoba Hydro from time to time for the class or classes of service supplied to the user".

Section 16 (2) of the Electric Power Terms and Conditions of Supply Regulation states: "All overdue and unpaid accounts are subject to a service charge".

QUESTION:

a) Section 15 (1) of this Regulation refers to rates established by Manitoba Hydro for power supplied. Are these "rates" the rates approved from time to time by the PUB or are there additional rates that are applicable under this section?

b) If there are additional rates that are applicable under Section 15 (1), please provide a schedule setting out what these rates are for each rate class.

RATIONALE FOR QUESTION:

To understand the "rates" customers are committing to pay in accordance with their Service Agreement and where those rates are documented.

RESPONSE:

a) Section 15(1) deals with rates for power. Rates for power are approved by the PUB.

b) All rates for power are contained in Manitoba Hydro's PUB approved rate schedules.

Section:	PUB MFR18	Page No.:	Attachment
Topic:	Terms and Conditions of Service		
Subtopic:	Service Agreement		
Issue:	Payments Required		

PREAMBLE TO IR (IF ANY):

Section 15 (1) of the Electric Power Terms and Conditions of Supply Regulation states: “The user shall pay Manitoba Hydro for power supplied at the rates, and for a period of time, not less than the minimum term, as established by Manitoba Hydro from time to time for the class or classes of service supplied to the user”.

Section 16 (2) of the Electric Power Terms and Conditions of Supply Regulation states: “All overdue and unpaid accounts are subject to a service charge”.

QUESTION:

c) If there are additional rates that are applicable please indicate how/where a customer would determine what the rates are?

RATIONALE FOR QUESTION:

To understand the “rates” customers are committing to pay in accordance with their Service Agreement and where those rates are documented.

RESPONSE:

A description of charges that may appear on a Manitoba Hydro bill (in addition to PUB approved rates for power), including late payment charges can be found at:

https://www.hydro.mb.ca/customer_services/how_to_read/your_bill/read_your_bill.html and https://www.hydro.mb.ca/customer_services/how_to_read/glossary.shtml

Section:	PUB MFR18	Page No.:	Attachment
Topic:	Terms and Conditions of Service		
Subtopic:	Service Agreement		
Issue:	Payments Required		

PREAMBLE TO IR (IF ANY):

Section 15 (1) of the Electric Power Terms and Conditions of Supply Regulation states: "The user shall pay Manitoba Hydro for power supplied at the rates, and for a period of time, not less than the minimum term, as established by Manitoba Hydro from time to time for the class or classes of service supplied to the user".

Section 16 (2) of the Electric Power Terms and Conditions of Supply Regulation states: "All overdue and unpaid accounts are subject to a service charge".

QUESTION:

d) Is the service charge applicable to overdue and undue accounts documented on the standard bill that a customer receives? If not, how/where would a customer determine what the associated service charge is?

e) Are there additional service charges/fees (e.g., account set-up fees, connection/reconnection charges, meter dispute fees, returned cheque fees, special meter read charges, credit check fees, security deposits, etc.) that Manitoba Hydro applies to customers that are not covered under the responses to parts (a) and (b)? If yes, please address the following:

i. What are the additional service charges/fees that may apply to customers?
ii. Where are these additional service charges/fees publicly documented such that customers are aware of them?
iii. Given they are not referenced in the Service Agreement, under what authority does Manitoba Hydro levy such charges?

RATIONALE FOR QUESTION:

To understand the "rates" customers are committing to pay in accordance with their Service Agreement and where those rates are documented.

RESPONSE:

d) Yes. It appears on page 2 of each customer's bill.

e) i and ii:

Please see Manitoba Hydro's response to COALITION/MH I-77c for a description of the service charges.

iii:

The response to this Information Request requires the provision of a legal opinion which Manitoba Hydro declines to provide.

Section:	PUB MFR18	**Page No.:**	Attachment
Topic:	Terms and Conditions of Service		
Subtopic:	Service Agreement		
Issue:	New versus Existing Services		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The Service Agreement provided in the Attachment to PUB MFR18 appears to be particularly applicable to customers seeking to establish a new service connection with Manitoba Hydro. Does the same agreement apply to customers who are simply seeking to receive electrical service at a location that is already connected to the Manitoba Hydro system (e.g., A residential customer who purchases and moves into an existing dwelling or a renter who moves in and is required, as part of the lease, to pay for the hydro used)? If not, please provide the Service Agreement that would apply in such situations.

RATIONALE FOR QUESTION:

To understand the applicability of the Service Agreement as filed.

RESPONSE:

Customers who receive service at a location that is already connected to the Manitoba Hydro system are not required to sign a Service Agreement. *The Manitoba Hydro Act (C.C.S.M. c. H190)*, Electric Power Terms and Conditions of Supply Regulation 186/90 applies to all customers.

Section:	PUB MFR18 MFR PUB16, 2012/12 & 13/14 GRA, GAC/MH II-38	Page No.:	Attachment Attachment 1
Topic:	Terms and Conditions of Service		
Subtopic:	Service Agreement		
Issue:	Payment and Notice Periods		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) It is noted that the Power Supply Agreement for GSL customers (GAC/MH II-38) contains specific sections dealing with: i) the payment period by when bills must be paid (Section 19) and ii) the notice period that will be given prior to disconnection of service. However, the Service Agreement applicable to other customers (MFR 18) does not contain similar provisions. Please indicate why this is the case and how similar information is provided to these customers.

RATIONALE FOR QUESTION:

To understand how customers are advised of their payment and disconnection notice periods.

RESPONSE:

The Service Agreement is used for new customer services and service upgrades for all rate classes and therefore the same “Standard Terms and Conditions for Electric Service Agreement” applies to all rate classes. In addition to the Service Agreement, GSL customers will enter into a Power Supply Agreement (Long Form Contract). Given the more costly and complex nature of the GSL facilities and their business requirements, the Power Supply Agreement provides more detail including an engineer’s drawing of the Point of Delivery.

Section:	MFR16, 2014/15&15/16 GRA, Coalition/MH I-34 b) PUBMFR18	**Page No.:**	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	Residential Service Customers		

PREAMBLE TO IR (IF ANY):

The response to the cited interrogatory states: "Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either the specified investment allowance (in the case of residential customers) or.."

QUESTION:

a) Please provide a copy of whatever information is provided to/made available to a prospective residential customer (or residential customers planning on increasing their load) regarding Manitoba Hydro's contribution policies and requirements.

b) Reference is made in the Service Agreement to a "point of delivery". For Residential customers how/where is the point of delivery typically established?

c) Please confirm that for Residential customers, the customer is responsible for providing and maintaining all facilities on the customer side of the point of delivery.

RATIONALE FOR QUESTION:

To understand how Manitoba Hydro's Service Extension Policy applies to Residential customers.

RESPONSE:

a) Once Manitoba Hydro receives a completed Application for Service (refer to Attachment 1 to this response) and detail on the new loads to be connected and site plans from the customer or their representative, Manitoba Hydro will supply the customer with an Electrical Service Agreement (refer to Attachment 2 to this response) which would outline the following:

- Description of Work
- Cost of Customer Request
- Applicable Allowance
- Customer Contribution
- Max Refundable Amount

For situations where an existing residential customer is requesting an upgrade to their service and no customer contribution is required to complete the upgrade, an Electrical Service Agreement is not issued as there are no changes to the original terms and conditions of their service.

b) Manitoba Hydro typically provides the Point of Delivery at the nearest corner of the building. This can be either the home or garage.

c) Confirmed.

CONDITIONS FOR ELECTRIC/GAS SERVICE / *CONDITIONS DU SERVICE D'ÉLECTRICITÉ ET/OU DE GAZ*

Upon completion of the Application for Electric/Gas Service, return it to your local Manitoba Hydro Office / *Une fois que vous avez rempli la Demande de service d'électricité et/ou de gaz, renvoyez-la au bureau de Manitoba Hydro de votre localité.*

FIRM PRICE QUOTATION / *PROPOSITION DE PRIX FERME*

Manitoba Hydro will provide you with a cost quotation for electric/gas service installation. Return the Electric Service Agreement/Application and Contract for Natural Gas Service and any payment, if required, to your local Manitoba Hydro Office. An in-service date will then be determined / *Manitoba Hydro vous soumettra un devis pour le branchement du service d'électricité et/ou de gaz. Veuillez retourner l'entente concernant le service électrique et/ou le formulaire de demande et le contrat de service de gaz naturel, ainsi que tout paiement requis, s'il y a lieu, au bureau de Manitoba Hydro de votre localité, où l'on déterminera une date d'entrée en service.*

NOTE / *REMARQUE* : **Manitoba Hydro normally requires a minimum of 90 days to meet a requested in-service date once a Contract/Agreement is signed / *Manitoba Hydro exige habituellement un préavis minimal de 90 jours à compter de la date de signature de l'entente ou du contrat pour effectuer le branchement à la date demandée.***

EASEMENTS / *SERVITUDES*

In accordance with the Real Property Act, utility easements (Right-of-Way) **may be** required to service your property. <u>It is your responsibility to obtain the easement(s)</u> / *Conformément à la Loi sur les biens réels, il **pourrait** être nécessaire d'obtenir des servitudes de services publics (emprise) pour brancher votre service. <u>C'est à vous d'obtenir la ou les servitudes.</u>*

BRUSH CLEARING AND GRADING / *DÉBROUSSAILLEMENT ET NIVELLEMENT*

Manitoba Hydro is responsible for determining line routes. Once a route to your property has been identified, you are responsible for the clearing of trees, bushes and other brush including the removal of logs, debris and/or snow. Prior to construction of the line route, you must establish a final grade level / *Manitoba Hydro est responsable du tracé des conduites. Une fois que le tracé vers votre propriété a été établi, vous êtes responsable de l'enlèvement des arbres et du débroussaillement, y compris l'enlèvement des billots, des débris et de la neige. Avant la construction des installations, vous devez déterminer un niveau du sol final.*

MISSING SURVEY MONUMENTS / *BORNES D'ARPENTAGE DISPARUES*

The Municipalities are responsible for the cost of replacing any lost or disturbed outline monuments required by Manitoba Hydro for construction. You are responsible for contacting a Manitoba Land Surveyor to liaise with the Municipality on your behalf to have the necessary monuments restored / *Les autorités municipales sont responsables des coûts liés au remplacement des bornes d'arpentage disparues ou déplacées qu'exige Manitoba Hydro pour les travaux de construction. Vous avez la responsabilité de communiquer avec un arpenteur-géomètre du Manitoba qui assurera la liaison avec les autorités municipales en votre nom en vue de la restauration des bornes nécessaires.*

PERMITS / *PERMIS*

Before commencing work, contractors or others responsible for carrying out the work shall first obtain a permit from the inspection authority. Manitoba Hydro will not connect any service until the work has passed inspection / *Avant de commencer les travaux, les entrepreneurs ou autres personnes responsables d'exécuter les travaux doivent d'abord obtenir un permis des autorités chargées de l'inspection des travaux. Manitoba Hydro ne branchera le service qu'après l'inspection réussie des travaux.*

GENERAL NOTES / *GÉNÉRALITÉS*

- In some instances, before installation of the line can begin, Manitoba Hydro must wait for authorization from public authorities, ie: railway and water crossings / *Dans certains cas, avant que l'installation de toute conduite ne puisse commencer, Manitoba Hydro doit attendre une autorisation de diverses autorités publiques (p. ex., pour traverser une voie ferrée ou un cours d'eau).*
- Manitoba Hydro normally supplies overhead lines. Underground lines are available, and requests are dealt with on an individual basis / *Manitoba Hydro fournit habituellement les lignes aériennes. L'entreprise offre aussi le branchement souterrain, mais les demandes sont traitées sur une base individuelle.*

1901R(1)/f
Rev 13 07

Manitoba Hydro

APPLICATION FOR ELECTRIC/GAS SERVICE - RESIDENTIAL / *DEMANDE DE SERVICE D'ÉLECTRICITÉ ET/OU DE GAZ (RÉSIDENTIEL)*

DATE OF APPLICATION / *DATE DE LA DEMANDE*	yyyy mm dd / *aaaa mm jj*

CUSTOMER WORKSHEET / *FEUILLE DE TRAVAIL DU CLIENT*

- ☐ NEW SERVICE / *NOUVEAU SERVICE*
- ☐ UPGRADE / *AMÉLIORATON*
- ☐ TEMPORARY SERVICE / *SERVICE TEMPORAIRE*

CUSTOMER INFORMATION / *RENSEIGNEMENTS SUR LE CLIENT*

NOTE / REMARQUE : Customer to complete Customer Information, Service Information, Contractor Information & Site Plan Sections as indicated / Le client doit remplir tel qu'indiqué les sections Renseignement sur le client, Renseignements sur le service, Renseignements sur l'entrepreneur et Plan du site.

Customer name #1 / *Nom du client n° 1*		Customer name #2 / *Nom du client n° 2*	
Home phone no. / *N° de tél.*	Business phone no. / *N° de tél. (travail)*	Cell no. / *N° de cellulaire*	Email address / *Adresse de courriel*
Street Address/P.O. Box no. / *Adresse municipale/Case postale*	CITY OR TOWN / *VILLE OU LOCALITÉ*	PROVINCE / *PROVINCE*	POSTAL CODE / *CODE POSTAL*
Provide Treaty number if work is being completed on First Nations Land / *Fournir le numéro de traité si les travaux sont effectués sur le terrain d'une Première Nation*	Current Energy Account no. / *N° de compte d'énergie actuel*		
Place of employment / *Employeur*			

DEFINTIONS / *DÉFINITIONS :*

Principal residence: a residence that is a customer's main or fixed address where /
Résidence principale : *une résidence qui est l'adresse principale ou fixe du client, et :*

- the customer claims the Manitoba Property Tax Credit; or / *où le client réclame le crédit d'impôts fonciers du Manitoba*
- is assessed the Chief Place of Residence Levy, for a residence within a Provincial Park by Manitoba Conservation / *qui se voit imposé, par Conservation Manitoba, l'impôt payable à l'égard des lieux principaux de résidence pour une résidence située dans un parc provincial.*

Seasonal residence : a residence that is NOT a principal residence and that is used on an intermittent or casual basis /
Résidence saisonnière : *une résidence qui n'est PAS une résidence principale et qui est utilisée de manière discontinue ou occasionnelle.*

SERVICE INFORMATION / *RENSEIGNEMENTS SUR LE SERVICE*

NOTE / *REMARQUE :* If Upgrades fill out lines indicated with ' * ' ONLY. If New Service fill out ALL fields / *Dans le cas d'améliorations, NE REMPLISSEZ QUE les champs indiqués par un *. Dans le cas d'un nouveau service, remplissez TOUS les champs.*

Service Address / *Adresse de service* *	EMO/911# / *N° de services d'urgence/911*	Road # / *N° de chemin*	
Street Address/P.O. Box no. / *Adresse municipale/Case postale*	**CITY OR TOWN / *VILLE OU LOCALITÉ* ***	PROVINCE / *PROVINCE*	POSTAL CODE / *CODE POSTAL*
Will this be your permanent residence / *S'agira-t-il de votre résidence permanente?* ☐ Yes / *Oui* ☐ No / *Non*	Will this be a seasonal residence / *S'agira-t-il d'une résidence saisonnière?* ☐ Yes / *Oui* ☐ No / *Non*	Is this part of a Subdivision / *L'adresse fera-t-elle partie d'une subdivision?* ☐ Yes / *Oui* ☐ No / *Non*	Provide size (provide dimensions) / *Fournissez la grandeur (dimensions)*

Type of Service / *Genre de service*
Electric Service / *Service électrique :* ☐ Overhead / *Aérien* ☐ Underground / *Souterrain*
Natural Gas / *Gaz naturel :* ☐ Yes / *Oui* ☐ No / *Non*
REQUESTED IN-SERVICE / *DATE DEMANDÉE POUR LA MISE EN SERVICE*: yyyy mm dd / *aaaa mm jj*

Heating Source / *Système de chauffage*
☐ Gas / *Gaz* ☐ Electric / *Électrique* ☐ Geo Thermal / *Géothermique* ☐ Other / *Autre*
Compressor motor size (HP) / *Compresseur - puissance du moteur (HP)*
Auxiliary Geothermal backup (kW) / *Chauffage auxiliaire pour système géothermique (kW)*

Load (Electric) / *Charge (électrique) :*
Heat Load in kW / *Charge de chauffage en kW :* _ _ _ _ _ _ _
Furnace / *Générateur d'air chaud :* _ _ _ _ _ _ _
Baseboard / *Plinthes chauffantes :* _ _ _ _ _ _ _
Service Size in Amps / *Capacité du service en ampères :* _ _ _ _ _ _ _

Load (Gas) / *Charge (gaz)*
Building connected (BTU's) / *Bâtiment raccordé (BTU) :* _ _ _ _ _ _ _
Furnace / *Générateur d'air chaud :* _ _ _ _ _ _ _
Fireplace / *Foyer :* _ _ _ _ _ _ _
Barbeque / *Barbecue :* _ _ _ _ _ _ _
Stove/Oven / *Cuisinière/Four :* _ _ _ _ _ _ _

CONTRACTOR INFORMATION / *RENSEIGNEMENTS SUR L'ENTREPRENEUR*

NOTE / *REMARQUE :* For New Service and Upgrade complete ALL fields in this section below / *Dans le cas d'un nouveau service ou d'une amélioration, remplissez TOUS les champs de la section ci-dessous.*

Contractor's name / *Nom de l'entrepreneur*	Phone no. / *N° de téléphone*	Cell no. / *N° de cellulaire*

SERVICE POINT/RISER LOCATION IS ESTABLISHED BY MANITOBA HYDRO / *MANITOBA HYDRO DÉTERMINERA L'EMPLACEMENT DU POINT DE BRANCHEMENT ET/OU DE LA COLONNE MONTANTE.*

MANITOBA HYDRO REPRESENTATIVE INFORMATION / *REPRÉSENTANT DE MANITOBA HYDRO*

Manitoba Hydro Contact / *Personne-ressource de Manitoba Hydro*	Phone no. / *N° de téléphone*	Fax no. / *N° de télécopieur*

This personal information is being collected under the authority of Program Activity. The purpose is to apply for electric or gas service to an existing or new residential customer. Other uses and disclosures may be to carry out program evaluation and market research, external auditors as part of a sample audit, external contractors and consultants to assist us in servicing your application and Manitoba Hydro officials on a "need to now" basis. It is protected by the Protection of Privacy provisions of *The Freedom of Information and Protection of Privacy Act.* If you have any questions about the collection, contact the Contact Centre of MANITOBA HYDRO, PO BOX 815 STN MAIN, WINNIPEG MG R3C 2P4 or telephone 204-360-4990 / *Les renseignements personnels sont recueillis en vertu des activités du programme. L'objectif de la collecte de renseignements est l'offre d'un service électrique ou de gaz à un nouveau client ou à un client existant résidentiels. Les renseignements peuvent également être divulgués à des fins d'évaluation du programme et d'études du marché, à des vérificateurs externes à des fins de vérification par échantillonnage, à des entrepreneurs et consultants externes en vue d'aider à traiter votre demande et, sur justification, à certains dirigeants de Manitoba Hydro. Les renseignements personnels sont protégés par les dispositions de protection de la vie privée de la* Loi sur l'accès à l'information et la protection de la vie privée. *Si vous avez des questions au sujet de la collecte des renseignements, veuillez communiquer avec le Centre de contact clientèle de MANITOBA HYDRO, CP 815, SUCC MAIN, WINNIPEG MB R3C 2P4 ou composer le 204 360-4990.*

Contro

Form: ZZ_QUOTE_ESA_CSI

Manitoba Hydro

Customer no.	Quotation no.

ELECTRIC SERVICE AGREEMENT ("AGREEMENT")

Customer name ("Customer")			
Mailing address		Location of service or work (if different from mailing address)	
City or Town	Postal Code		
Customer Representative	Phone No.	Manitoba Hydro Contact Name	
Instructions to Customer	Please review this agreement thoroughly and if you accept: a) sign and date the agreement below, in the presence of a witness who must also sign; and b) return one signed original with required payment before the Deadline	Manitoba Hydro Contact Phone No. Return signed Agreement and payment to	

Price Quote Valid until: ("Deadline")	yyyy mm dd	Requested inservice date ("Inservice Date") Date may be changed in consultation with Customer	yyyy mm dd	To meet the Inservice Date, Agreement must be signed and returned by	yyyy mm dd

Protection of Privacy	This personal information is being collected under the authority of Program Activity and *The Manitoba Hydro Act* . The purpose is to provide electric service to a new or existing customer and document customer contribution, allowances and refunds. Other uses and disclosures may be to the SAP System to complete the work order process, Lotus Notes Refundables database to process refunds, external collection agencies for recovering delinquent accounts, external auditors as part of a sample audit, and Manitoba Hydro officials on a "need to know" basis. It is protected by the Protection of Privacy provisions of *The Freedom of Information and Protection of Privacy Act.* If you have any questions about the collection, contact____________, or telephone 1 888 624-9376.

MANITOBA HYDRO AND THE CUSTOMER AGREE AS FOLLOWS:

Power & Energy: Supply, Rates, and General Terms (if applicable)	1. Manitoba Hydro shall make available to the Customer up to, but not more than, ____ kilovolt-amperes of electric power and energy to be used for the operation of a: ___ at ___. 2. The Customer shall pay for such power and energy in accordance with Manitoba Hydro's applicable electric service tariff and/or rates, for a minimum term of three years from the requested Inservice Date, and thereafter from month to month. 3. If, during the term of this Agreement, Manitoba Hydro makes any revision to its electric service tariff and/or rates, the new tariff and/or rates shall apply from and after the effective date of such revision. 4. If after three years from the requested Inservice Date, the Customer requests Manitoba Hydro to discontinue service and subsequently within five years of such discontinuance, the Customer requests service at the same location again, the Customer shall pay Manitoba Hydro an amount equal to the total minimum bills from the date of discontinuance plus the full cost of restoring service. 5. The "Standard Terms and Conditions for Electric Service Agreement" on the reverse hereof shall be applicable to this Agreement, and the Customer shall observe and be bound by the *Electric Power Terms and Conditions of Supply Regulation*, Man. Reg. 186/1990, on the reverse hereof, and as amended from time to time, and the laws, rules, regulations, bylaws and standards governing the construction, installation, maintenance, repair, extension, alteration and use of electric wiring and related facilities using or intended to use power supplied by Manitoba Hydro.
Motors	Motor Start Restrictions: ☐ Yes (See attached letter) ☐ No
Guaranteed Minimum Billing (if applicable)	The Customer guarantees to pay a minimum annual billing total of $____ ("Guaranteed Minimum") for the first three years following the Inservice Date. Should the total monthly billing in any year during the said three year period be less than the Guaranteed Minimum, an additional bill shall be issued to the Customer at the end of such year ("13th bill"). The 13th bill shall be equal to the Guaranteed Minimum less the actual annual billing total.

Customer Request	Description of Work	Cost of Customer Request	$
Allowance	Basis of allowance, if applicable	Applicable Allowance and/or Discount	$
		Subtotal	$
GST		GST based on Cost of Customer Request less Applicable Allowance Manitoba Hydro GST Registration No. : R122063779	$
→	Manitoba Hydro will schedule the work after receipt of payment	Required Payment	$
Refund	**Conditions which must be met within ___years to qualify for partial refund are:** ☐ Additional customer shares extension ☐ Principal I Seasonal Residency established ☐ Additional load qualifies for 3 Phase rebate ☐ Additional load qualifies for padmount rebate ☐ Permanency established ☐ Additional revenue	Maximum refundable (excluding GST) **Customer: If your service qualifies as permanent or your load increases to meet the qualifications, please call** Manitoba Hydro to arrange a review. Initial review date	$ yyyy mm dd
Customer's Authorization	The undersigned requests and authorizes Manitoba Hydro to do the work, certifies that customers contributing to the required payment are all identified below and signatories hereto, and accepts the terms and conditions on the reverse hereof. Customer's signature ______ Date ______ Customer name (and title, if applicable) (please print) Witness ______ Date ______ Witness print name	Agreement prepared and approved by	yyyy mm dd

STANDARD TERMS AND CONDITIONS FOR ELECTRIC SERVICE AGREEMENT

1. Customer's Responsibilities:
   a) It is the Customer's responsibility, without charge to Manitoba Hydro:
      i) to prepare the line route, including grading and clearance of brush and obstacles;
      ii) to provide all facilities required to enable Manitoba Hydro to connect its electrical distribution system at the point of delivery;
      iii) to provide any landscaping;
      iv) to provide space and right-of-way for Manitoba Hydro's facilities; and
      NOTE: Easements are usually required to establish a right-of-way or an allocation of space. In rural areas, or areas serviced by diesel, or if the work involves outdoor lighting, the customer may have to acquire easements from other property owners.
      v) to abide by the requirements of the Manitoba Electrical Code and the current design requirements of Manitoba Hydro.

   b) If the Customer fails to connect a new service extension within sixty days after being notified that service is available, the Customer must:
      i) pay a minimum basic charge as if connected until minimum term of service is completed; and
      ii) if service remains unconnected following completion of minimum term, either retain the service extension by continuing minimum payment or declare the extension available for salvage.

2. Revision of Agreement:
   Manitoba Hydro reserves the right to revise the Agreement if the Customer:
   a) changes the specifications or details upon which the Agreement is based;
   NOTE: If additional design costs are incurred by Manitoba Hydro because of a change requested by a Customer subsequent to presentation of the Agreement, Manitoba Hydro may require that all estimated additional design costs be paid. Such a payment is NOT eligible for allowance or refund.

2. Revision of Agreement (Continued):
   b) causes the work to be rescheduled to a period in which different cost schedules apply, through failure to complete the Customer's Responsibilities (see Condition 1.a), or by request.
   NOTE: New cost schedules are effective January 1 of every year; and during the period December 1 through March 31, higher prices may apply.

3. Refunds:
   a) The Customer who executes this Agreement shall:
      i) identify all persons who contribute and the portion each is contributing to the payment required;
      ii) indemnify and save harmless Manitoba Hydro from and against any and all claims to any refund made or withheld in accordance with this quotation.
   b) Where the Customer who executes this Agreement directs Manitoba Hydro in writing to pay any refund to another (others), any refund will be paid in accordance with that direction.
   c) Where there is more than one Customer contributing to the payment required, each Customer shall be paid a refund which is in proportion to his or her original contribution.

GENERAL NOTES

4. In some cases, Manitoba Hydro must await official action by public authorities before doing the work. For example:
   a) authorization of street lighting by municipal council;
   b) designation of subdivision for underground residential distribution by municipal council;
   c) review of certain street lighting proposals with regard to traffic and safety by Department of Highways; and/or
   d) inspection and approval of the Customer's electric service facilities (prior to connection) by electrical inspector.

5. The Customer's payment is a customer contribution toward Manitoba Hydro's costs. Manitoba Hydro retains ownership of the facilities.

Electric Power Terms and Conditions of Supply Regulation Man. Reg. 186/1990 (pursuant to *THE MANITOBA HYDRO ACT,* C.C.S.M. c4190)

Definition
1 In this regulation, "power" means electric power and electric energy.

Terms and conditions of supply
2 Power is supplied by Manitoba Hydro to users upon and subject to the terms and conditions set out in this regulation.

Grant of right-of-way and passage
3 The user will grant to, or obtain for, Manitoba Hydro a free and uninterrupted right-of-way and passage in, over, under, and upon the land upon which the user's premises are situated, for the purposes of constructing, installing, maintaining, using, and removing the wires, facilities, and equipment required to supply power to the user, or to any other user supplied by Manitoba Hydro.

Point of delivery
4 The point of delivery for power is a point which Manitoba Hydro shall designate.

Connecting wires, etc.
5 The user will provide all wires, facilities and equipment required to connect the user's premises to Manitoba Hydro's electrical distribution system at the point of delivery, and shall maintain those wires, facilities, and equipment in a condition that Manitoba Hydro regards as safe and efficient.

Measurement of Power
6 All power supplied by Manitoba Hydro (other than that supplied on a flat rate basis), shall be measured at or near the point of delivery by means of a suitable meter or meters supplied by Manitoba Hydro, which shall be of commercial accuracy, and approved, tested, and sealed by the Department of Consumer and Corporate Affairs, (Canada).

Meter space and risk of damage
7 The user shall provide and maintain without charge, convenient, accessible, and safe space at or near the point of delivery for Manitoba Hydro's meters, wires, facilities, and equipment, which shall be in the care and at the risk of the user, and if lost, destroyed, or damaged, (other than by ordinary wear and tear), the user shall pay Manitoba Hydro on demand an amount equal to the value thereof, or the cost of repairing and replacing them as determined by Manitoba Hydro.

Right of access by Manitoba Hydro
8 Authorized employees of Manitoba Hydro shall at all reasonable times have free and uninterrupted access to the user's premises for the purpose of reading Manitoba Hydro's meters.

User not to permit removal of equipment
9 The user will not permit anyone who is not an authorized employee of Manitoba Hydro to remove, handle or tamper with Manitoba Hydro's meters, wires, facilities, and equipment.

Characteristics of power
10 The user shall operate his electrical equipment in a manner that will not cause Manitoba Hydro's power supply to vary in voltage, frequency, and wave form in excess of that which can be considered commercially tolerable.

Operation of electrical equipment
11 The voltage, frequency, phasing, and other characteristics of power shall be determined by Manitoba Hydro, the determination of which is final and binding on the user.

Limit of liability
12 Manitoba Hydro shall use reasonable diligence in providing the user with a regular and uninterrupted supply of power; but Manitoba Hydro is not liable for any loss, costs, damages, or expenses directly or indirectly resulting from any fluctuation, interruption, reduction, or failure in the supply of power.

Notice to Manitoba Hydro of certain changes
13 The user shall notify, or cause to be notified, Manitoba Hydro in writing within ten days of any alterations in the user's wiringor water heater, or other use of power provided by Manitoba Hydro that should result in a change in the applicable rate.

Restriction on use of power
14 The user will not permit power supplied by Manitoba Hydro to the user to be used by, or for the benefit of, any other person, firm, or corporation, either directly or indirectly, without the prior written approval of Manitoba Hydro; any such use or benefit, if approved is subject to any special terms and conditions that may be imposed by Manitoba Hydro.

Payment for power
15(1) The user shall pay Manitoba Hydro for power supplied at the rates, and a period of time, not less than the minimum term, as established by Manitoba Hydro from time to time for the class or classes or service supplied to the user.

Where no meter reading
15(2) If a meter fails to register, or fails to register correctly, or if for any reason whatsoever meter readings are unobtainable, the amount of power supplied by Manitoba Hydro to the user may be estimated by Manitoba Hydro from the best information available.

Right to estimated consumption
15(3) If Manitoba Hydro reads a user's meter less frequently than once per billing period, Manitoba Hydro may submit an account based on an estimate of the amount of power supplied to that user in a billing period.

Account for estimate consumption
15(4) An account based on an estimate of the amount of power supplied to the user in a billing period will have the same force and effect as an account based upon an actual meter reading.

Due date of account
16(1) Accounts for power submitted by Manitoba Hydro to a user are due and payable on the date indicated thereon.

Service charges
16(2) All overdue and unpaid accounts are subject to a service charge.

Remedy for default by user
17 Where a user is in default in payment of any account for power submitted by Manitoba Hydro (including any tax which may be levied on it), or if a user ignores or fails to observe any or all ofthese terms and conditions, Manitoba Hydro may, at its option, discontinue the supply of power to the user and remove its meters, wires, facilities, and equipment from the user's premises; and Manitoba Hydro is not liable for loss or damage resulting from any such discontinuance or removal.

Effect of violation by user
18 Violation of any of these terms and conditions by the user does not relieve the user of his obligation to pay for the balance, if any, of the minimum term applicable to the class of service that was provided by Manitoba Hydro.

Repeal
19 Manitoba Hydro Regulation H190-Rl is repealed.

Signature under the Customer's Authorization indicates that the Customer accepts all of the terms and conditions herein and that the Customer has requested that this Agreement be drawn up in the English language

Section:	MFR16, 2014/15&15/16 GRA, Coalition/MH I-34 b) PUBMFR18	**Page No.:**	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	Residential Service Customers		

PREAMBLE TO IR (IF ANY):

The response to the cited interrogatory states: "Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either the specified investment allowance (in the case of residential customers) or.."

QUESTION:

d) What types of costs are taken into account when determining the "cost of extending service or the cost of accommodating load increase". For example, does it include just the cost of new lines to reach the customer's point of delivery or does it also include the costs of any additional transformation upgrades, primary/secondary distribution upgrades to existing facilities, upgrades to substations, transmission upgrades or additional generation requirements? In responding please describe how the new facilities for which contributions are required are functionalized (and sub-functionalized) in Manitoba Hydro's COSS.

e) What is the "specified investment allowance" for residential customers, what is it based on and how frequently is it updated?

RATIONALE FOR QUESTION:

To understand how Manitoba Hydro's Service Extension Policy applies to Residential customers.

RESPONSE:

d) The cost to provide a service extension to a new residential customer will include the costs associated with all dedicated facilities on public and private property and the costs of required easements and permits.

The Corporation's practice for residential customer upgrades is to charge the customer for all dedicated facilities on public or private property that may be required for a larger service if the original service has been connected less than three years. The costs to upgrade any shared facilities including primary/secondary distribution, substations, transmission and generation requirements will not be charged to that customer requiring the service upgrade.

Manitoba Hydro does not consider how assets were funded when functionalizing the cost of new facilities in the COSS, and does not attribute the facility to an individual customer. The cost of the facility, net of the amount funded via customer contribution, is functionalized (and sub-functionalized) consistent with the treatment of other assets of the same type for allocation to all customers that utilize the function or sub-function.

e) The applicable allowance for a single family residential customer is the lesser of:

1) the cost of an overhead distribution system or;
2) the corporations residential extension allowance as applied to the following three categories:
   - All electric heated home maximum allowance of $4,000,
   - Standard heated home maximum allowance of $1,600 or
   - Seasonal home maximum allowance of $800.

Manitoba Hydro periodically reviews its overall level of investment allowance for service extensions. Overall residential investment allowances for electrically heated, standard and seasonal homes were revised in 2014. This revision reflected a movement from an allowance that was notionally based on three times annual revenue to two times annual revenue.

The investment allowance for residential customers situated outside of urban centers was harmonized with the investment allowances provided for urban customers, effective January 1, 2016.

Section:	MFR16, 2014/15&15/16 GRA, Coalition/MH I-34 b) PUBMFR18	Page No.:	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	General Service (Small and Medium) Customers		

PREAMBLE TO IR (IF ANY):

The response to Coalition/MH I-34 b) states: "Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either … or the amount of investment allowance as determined by a revenue test for General Service customers served at voltages less than 30 kV."

PUB MFR18 notes that: "Manitoba Hydro would normally invest up to three times forecast annual revenue to extend service to a customer. For customers served at less than 30 kV, there are additional limitations on the amount Manitoba Hydro will invest in dedicated facilities on private property and in special services such as underground service, seasonal residences, location of point of delivery, three phase service and pad mount transformers. In all cases, if the extension cost is greater than Manitoba Hydro's Allowance, a Customer Contribution is required to make up the difference."

QUESTION:

a) Please provide a copy of whatever information is provided to/made available to prospective a General Service Small or Medium customer (or General Service Small and Medium customers planning on increasing their load) regarding Manitoba Hydro's contribution policies and requirements.

b) Reference is made in the Service Agreement to a "point of delivery". For General Service Small and Medium customers how/where is the point of delivery typically established?

c) Please confirm that for General Service Small and Medium customers, the customer is responsible for providing and maintaining all facilities on the customer side of the point of delivery.

RATIONALE FOR QUESTION:

To understand how Manitoba Hydro's Service Extension Policy applies to General Service Small and Medium customers.

RESPONSE:

a) Once Manitoba Hydro receives a completed Application for Service (refer to Attachment 1 to this response), detail on the new loads to be connected and site plans from the customer or their representative, Manitoba Hydro would supply the customer with an Electrical Service Agreement (refer to Attachment 2 of COALITION/MH I-80a-c), which would outline the following:
   - Description of Work
   - Cost of Customer Request
   - Applicable Allowance
   - Customer Contribution
   - Max Refundable Amount

b) Manitoba Hydro typically provides the Point of Delivery at the nearest corner of the building or load-centre being served, and may go up to 210m on private property. If a customer requests an alternate preferred service point which is not the nearest or preferred location as determined by Manitoba Hydro, a Customer Preferred Service Premium will be applied to the incremental plant to be installed.

c) Confirmed.

1901A/f
Rev 10 08
v1.6

APPLICATION FOR ELECTRIC/GAS SERVICE - COMMERCIAL

CUSTOMER INFORMATION (Please print)

Customer name

Home phone | Business phone

Mailing address

CITY OR TOWN | PROVINCE | POSTAL CODE

Location of service

ELECTRICAL/GAS PLANS AND SPECIFICATIONS

Provide two copies of the site, grade, electrical and mechanical plans to assist Manitoba Hydro in the design for the following (indicate what is being included):

	Site	Grade	Electrical	Mechanical
Single phase, for all services over 200 amperes	☐	☐	☐	☐
Three phase, for all services	☐	☐	☐	☐
Underground service facilities	☐	☐	☐	☐
Gas servicing (Note: Construction of a structure over top of a gas service is prohibited by code.)	☐	☐	☐	☐

INCLUDE THE FOLLOWING INFORMATION

Contractor or Consultant's name

Contractor or Consultant's phone no.

TOTAL LOAD (ELECTRIC)

Heat load in kW

Furnace: ____________ Baseboard: ____________

Lighting load: ____________ Air conditioning: ____________

Miscellaneous load: ____________ Total motor load (hp): ____________

Largest motor size (>5.0 hp): ____________ Starts per hour/day: ____________

Additional motor size (>5.0 hp): ____________ Starts per hour/day: ____________

Additional motor size (>5.0 hp): ____________ Starts per hour/day: ____________

Additional motor size (>5.0hp): ____________ Starts per hour/day: ____________

Fault current levels required? ☐ Yes ☐ No

Estimated demand in kVA: ____________

TOTAL LOAD (GAS)

Building connected load (total btu's) | Future connected load (total btu's)

Pressure requested

☐ 7" W.C. ☐ 2 psi ☐ 5 psi ☐ Other

Manitoba Hydro contact name

Contact phone no. | Fax no.

SERVICE INFORMATION

APPROXIMATE IN-SERVICE DATE: yyyy mm dd

Dimensions of building ft^2/ m^2

Service size (in amps)

Distance from property line to building ft/metres

Type of service (indicate all applicable categories)

ELECTRIC

☐ Overhead
☐ Underground
☐ Temporary Service

Voltage:
☐ 120 / 240 volt single phase*
☐ 120 / 208 volt three phase*
☐ 347 / 600 volt three phase*

*Manitoba Hydro supply voltages.

☐ **GAS**

NOTE: Service point location is established by Manitoba Hydro. Customer preferred service points may be available at customer's expense except in pre-serviced underground subdivisions. Gas service located on front or side of building based on gas main location. Manitoba Hydro to determine final riser location.

NON-LINEAR LOAD INFORMATION

Type of service (indicate all applicable categories)

1. Computer:
   New: ____________ kW Existing: ____________ kW
2. Variable frequency drive:
   New: ____________ kW or hp Existing: ____________ kW or hp
   - ☐ Standard 6-pulse
   - ☐ 6-pulse w/series reactor
   - ☐ 12-pulse
   - ☐ 24-pulse
   - ☐ Other
3. Electronic lighting:
   New: ____________ kW Existing: ____________ kW
   - ☐ Standard ballast
   - ☐ Energy efficient ballast
   - ☐ Other
4. Melting furnace:
   New: ____________ kW Existing: ____________ kW
   - ☐ Induction
   - ☐ Arc
   - ☐ Other
5. Welding:
   New: ____________ kW Existing: ____________ kW
6. Other, please specify: ____________
   New: ____________ kW Existing: ____________ kW
7. Power factor correction:
   New: ____________ kVAR Existing: ____________ kVAR
   - ☐ Fixed
   - ☐ Switched

NOTE: See reverse for CONDITIONS FOR ELECTRIC/GAS SERVICE.

1901A/r Rev 10 08

CONDITIONS FOR ELECTRIC/GAS SERVICE

Upon completion of the Application for Electric/Gas Service, return it to your local Manitoba Hydro Office.

FIRM PRICE QUOTATION

Manitoba Hydro will provide you with a cost quotation for electric/gas service installation. Return the Electric Service Agreement/Application and Contract for Natural Gas Service and any payment, if required, to your local Manitoba Hydro Office. An in-service date will then be determined.

NOTE: Manitoba Hydro normally requires a minimum of 90 days to meet a requested in-service date once a Contract/Agreement is signed.

EASEMENTS

In accordance with the Real Property Act, utility easements (Right-of-Way) **may be** required to service your property. It is your responsibility to obtain the easement(s).

BRUSH CLEARING AND GRADING

Manitoba Hydro is responsible for determining line routes. Once a route to your property has been identified, you are responsible for the clearing of trees, bushes and other brush including the removal of logs, debris and/or snow. Prior to construction of the line route, you must establish a final grade level.

MISSING SURVEY MONUMENTS

The Municipalities are responsible for the cost of replacing any lost or disturbed outline monuments required by Manitoba Hydro for construction. You are responsible for contacting a Manitoba Land Surveyor to liaise with the Municipality on your behalf to have the necessary monuments restored.

PERMITS

Before commencing work, contractors or others responsible for carrying out the work shall first obtain a permit from the inspection authority. Manitoba Hydro will not connect any service until the work has passed inspection.

GENERAL NOTES

- In some instances, before installation of the line can begin, Manitoba Hydro must wait for authorization from public authorities, ie: railway and water crossings.
- Manitoba Hydro normally supplies overhead lines. Underground lines are available, and requests are dealt with on an individual basis.
- An allowance **may be** applied toward the cost of three phase service if the following condition exists:

  a) a single unit of inductive load 20 hp (kVA) and greater.

  Otherwise, the allowance is applied toward the cost of single phase service of equivalent capacity.

Section:	MFR16, 2014/15&15/16 GRA, Coalition/MH I-34 b) PUBMFR18	Page No.:	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	General Service (Small and Medium) Customer		

PREAMBLE TO IR (IF ANY):

PUB MFR18 notes that: "Manitoba Hydro would normally invest up to three times forecast annual revenue to extend service to a customer. For customers served at less than 30 kV, there are additional limitations on the amount Manitoba Hydro will invest in dedicated facilities on private property and in special services such as underground service, seasonal residences, location of point of delivery, three phase service and pad mount transformers. In all cases, if the extension cost is greater than Manitoba Hydro's Allowance, a Customer Contribution is required to make up the difference."The response to Coalition/MH I-34 b) states: "Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either … or the amount of investment allowance as determined by a revenue test for General Service customers served at voltages less than 30 kV."

QUESTION:

d) What types of costs are taken into account when determining the "cost of extending service or the cost of accommodating load increase". For example, does it include just the cost of new lines to reach the customer's point of delivery or does it also include the costs of any additional transformation upgrades, primary/secondary distribution upgrades to existing facilities, upgrades to substations, transmission upgrades or additional generation requirements? In responding please describe how the new facilities for which contributions are required are functionalized (and sub-functionalized) in Manitoba Hydro's COSS.

e) Is the "revenue test" referred to in Coalition/MH I-34 b) the "three times forecast annual revenue" referenced in PUB MFR18? If not, what is the "test"?

f) How is the load forecast used for the revenue test established and are there any adjustments if actual load turns out to be materially higher or lower than forecast?

g) Is all of the revenue forecast to be received from the customer used in the test or just the portion that is associated with recovering the costs of the assets considered in the test (per the response to part (d))?

RATIONALE FOR QUESTION:

To understand how Manitoba Hydro's Service Extension Policy applies to General Service Small and Medium customers.

RESPONSE:

d) The cost to provide a service extension for a new GSS or GSM customer will include the cost associated with all dedicated Corporation facilities on public property, dedicated facilities on private property, the cost of required easements and permits and the cost associated with increasing the capacity of shared distribution transformers.

For an existing GSS or GSM customer undergoing a load increase, the cost associated with modification or replacement of transformers (both dedicated and shared) and secondary facilities will be included in that customer's cost responsibility.

Given the relatively small size of these load additions, Manitoba Hydro does not generally include costs related to other changes to the integrated system such as the advancement of substation or transmission system upgrades or future generation requirements when considering the addition of individual GSS or GSM customer loads.

Manitoba Hydro does not consider how assets were funded when functionalizing the cost of new facilities in the COSS, and does not attribute the facility to an individual customer. The cost of the facility, net of the amount funded via customer contribution, is functionalized (and sub-functionalized) consistent with the treatment of other assets of the same type for allocation to all customers that utilize the function or sub-function.

e) Manitoba Hydro can confirm that the "revenue test" referred to in COALITION/MH I-34b from the 2014/15 & 2015/16 GRA is the "three times forecast annual revenue" referenced in PUB MFR 18.

Response to parts f) and g):

Manitoba Hydro will only consider the incremental revenue to be obtained from new customer attachment or from the increase in existing customer load in the calculation of the revenue test. An estimate of the customer's increased load and expected revenue is forecast based on information provided by the customer and from Manitoba Hydro's knowledge of other facilities with a similar load profile.

Customer attachments or load increases are examined after three years of operation and the customer contributions or refunds are trued up after the account is reviewed.

Section:	PUB MFR18	**Page No.:**	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	Customers < 30 kV		

PREAMBLE TO IR (IF ANY):

PUB MFR 18 states: "For customers served at less than 30 kV there are additional limitations on the amount Manitoba Hydro will invest in dedicated facilities on private property and in special services such as underground service, seasonal residences, location of point of delivery, three phase service and pad mount transformers."

QUESTION:

a) Please fully explain the nature of each of these limitations and how they impact the amount of contribution that will be required from the customer.

b) Please provide a copy of whatever information is provided to/made available to a prospective <30 kV customer (or <30 kV customers planning on increasing their load) regarding these limitations.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's Service Extension Policy.

RESPONSE:

a) Manitoba Hydro's investment in dedicated facilities on private property varies depending on the type of customer, size of service and their location as discussed below. Any facilities beyond limits for dedicated facilities on private property may require a customer contribution.

- Customers are responsible for the incremental cost difference between an underground service and Manitoba Hydro's basic overhead distribution system.

Customers only qualify for allowance to be applied to a pad-mounted transformer, when their load exceeds the capacity of overhead transformation.

- Manitoba Hydro will only invest in the Corporation's preferred point of delivery within limits on private property and any customer-requested preferred point of delivery may require a customer contribution.

- For residential customers, the Corporation's investment in plant situated on private property is limited to an overhead service drop for a principal residence, seasonal residence or a non dwelling service. Principal residences in rural locations outside of urban centers are limited to seventy meters of overhead distribution and a service drop on private property.

- General Service Small and General Service Medium customers are limited to the application of revenue allowance to dedicated facilities on private property to include Corporation owned transformation, 210 meters of overhead distribution and a service drop. General Service Small and General Service Medium seasonal customers are limited to a service drop on private property.

- Manitoba Hydro will not apply allowance to dedicated facilities on private property for General Service Large customers (exceeding 750 volts to not exceeding 30 kV).

- Manitoba Hydro may apply allowance to a three phase service if the transformation required to service the customer's load exceeds the limitation of a single phase service, or the corporation's preference is to serve the load with three phase power. For example, the corporation preference maybe to serve the customer with three phase power even though the customer's load does not exceed the limitations of a single phase service in the event that an existing three phase transformer in proximity to the customer has the available capacity to serve the customer's load.

b) Please see Manitoba Hydro's response to COALITION/MH I-81a-c.

Section:	PUB MFR18	Page No.:	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	Customers < 30 kV – with Customer Owned Transformation		

PREAMBLE TO IR (IF ANY):

PUB MFR 18 also states: “For customers who own their own transformation, there are additional considerations. The maximum allowance for primary voltage service (other than those exceeding 30 kV or loads exceeding 5 MW where the customer owns the transformation) is three times the estimated annual revenue and is applicable only to facilities not on private property.”

QUESTION:

a) Please explain more fully the difference in treatment as between those customers served at <30 kV (and with less than 5 MW of load) who own their own transformation and those who do not.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro’s Service Extension Policy.

RESPONSE:

General Service Large Customers own their own transformation and those which are served at voltages less than 30 kV having new load less than 5 MW may have the revenue allowance applied to facilities to be constructed on public property. However, any plant to be situated on private property is not eligible for the revenue allowance.

General Service Small and Medium Customers utilize corporation owned transformation and may have the revenue allowance applied to facilities constructed on public property and on private property within limits.

Section:	PUB MFR18	Page No.:	
Topic:	Service Extension Policy		
Subtopic:	Capital Contributions		
Issue:	Customers > 30 kV or > 5 MW		

PREAMBLE TO IR (IF ANY):

PUB MFR 18 further states: "No allowance is applied to facilities required to serve new loads exceeding 30 kV or loads in excess of 5 MW without approval of Manitoba Hydro's Executive Committee".

QUESTION:

a) Please clarify what is meant by "new loads". Does this include both new customers and existing customers seeking to increase their load?

b) If the latter are not included, please explain what allowance is provided and how it is determined.

c) For these customers, what types of costs are taken into account when determining the cost of extending service or the cost of accommodating load increase for purposes of establishing the required contribution. For example, does it include just the cost of new transmission and sub-transmission lines to reach the customer's point of delivery or does it also include the costs of any additional upgrades to new substations and or additional generation requirements required to supply the customer? In responding please explain how the new facilities for which contributions are required are functionalized (and sub-functionalized) in Manitoba Hydro's COSS.

d) How does Manitoba Hydro's Executive Committee determine whether an "allowance" will be provided and, if so, how the amount will it be determined?

e) To-date, has Manitoba Hydro's Executive Committee approved an "allowance" for new loads exceeding 30 kV or loads in excess of 5 MW? If yes, what were the circumstances and what was the basis for the allowance?

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's Service Extension Policy as it applies to customers>30 kV (or >5 MW).

RESPONSE:

Response to parts a) and b):

New load refers to the both the attachment of new customers and the increase in load at existing customers on the system.

c) The customer will be responsible for the capital costs of constructing or re-building sub-transmission and transmission facilities (if required) from the customer's point of delivery back to the point of interconnection with the integrated utility system. The customer would also be responsible for the cost associated with any system upgrades required on assets situated on the integrated system, including sub-stations, transformation, switch gear, breakers, system protection and other facilities used to serve the new or increased load. Manitoba Hydro does not typically include any estimate of the cost of incremental new generation in the customer contribution.

d) Executive Committee considers a Recommendation that outlines the costs and benefits to Manitoba Hydro of the associate infrastructure improvement and evaluates the economics of the proposal to determine whether the recommendation is in the best interests of Manitoba Hydro and its ratepayers.

e) Executive Committee has approved, on one occasion, the revenue testing of an expansion of existing load connecting to the 33 kV system. This specific situation was approved as it represented the least cost alternative to the Manitoba Hydro system. The other alternative was to continue to serve the customer from the existing 12 kV system and undertake a significant capital cost to upgrade that portion of the system to accommodate the increased load. The decision to migrate the customer load to the 33 kV system was more economically viable than an upgrade to the 12 kV system to maintain that load at the existing voltage.

Section:	MIPUG MFR 4 MIPUG MFR 6 PUB MFR 13	Page No.:	
Topic:	Cost of Service Study		
Subtopic:	PCOSS14-Amended		
Issue:	Compliance with Board Directives (117/06 & 116/08)		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) PUB MFR 13 indicates that previous Board directives (see PCOSS08 column) included that Transmission-Interconnections were to be classified as demand- related and allocated using 2CP. However, in MIPUG MFR 4 (Schedule E1) it appears they were classified as energy and allocated using weighted energy. Please confirm the treatment of Transmission-Interconnections in MIPUG MFR 4 as filed and whether it reflects the Board directed treatment per Orders 117/06 and 116/08.

b) MIPUG MFR 13 indicates that previous Board directives (see PCOSS08 column) were that Dorsey be functionalized as Transmission, classified as demand- related and allocated using 2CP. Was the treatment of Dorsey as transmission reflected in the materials provided in MIPUG MFR 4

c) Please explain why the total Operating costs are different as between the COSS study result provided in MIPUG MFR 4 ($798,969.4 k) and PCOSS14-Amended ($783,284 k per Appendix 3, Schedule E1).

d) Please confirm that the difference in Interest costs as between MIPUG MFR 4 ($528,147.04 k) and Appendix 3 ($548,612 k) is due entirely to the use of recent actual export prices to determine export revenue in MIPUG MFR 4.

e) Please explain why the costs directly assigned to SEP (both generation and transmission) differ between MIPUG MFR 4 and Appendix 3.

f) Please provide a revised version of MIPUG MFR 4 corrected as required based on the responses to parts (a) through (e).

g) Please provide an Excel COSS model supporting the results set out MIPUG MFR 4 (revised).

h) MIPUG MFR 6 does not appear to address the proposed changes in the classification and allocation of Transmission-Interconnections, the functionalization and subsequent treatment of Dorsey or the explicit introduction of capacity costs into the weighted energy allocator. Please provide a revised version that also includes these changes.

RATIONALE FOR QUESTION:

To understand the results of PCOSS based on current Board directives.

RESPONSE:

As Manitoba Hydro stated in response to MIPUG MFR 4, the Cost of Service schedules provided reflect the 2013/14 test year with modifications to reflect those issues in Order 116/08 to which it views inconsistent with cost causation and therefore inappropriate for use in depicting cost responsibility by class. Other modifications to methodology that Manitoba Hydro has adopted into its cost allocation practices resulting from the independent review of its Cost allocation methodology undertaken were not reflected. For example, the treatment of Dorsey. In Order 7/03 (page 98), which was not subject to the 2005 or 2008 proceedings, the PUB encouraged Manitoba Hydro to re-evaluate the appropriateness of its treatment as solely Transmission-related, allocated on the basis of 2CP. This change and others, as well as other methodology re-affirmed, such as the treatment of Bipoles (including Bipole III) flowing from the recent independent review were not viewed reasonable to have been included in the analysis. A list of specific changes made to address Order 116/08 in the context of PCOSS14 was provided. All other changes in methodology were not reflected in that analysis.

a) US Interconnections have been classified as energy and allocated using weighted energy.

b) Dorsey convertor station was functionalized as Generation in MIPUG MFR 4.

c) Consistent with the use of recent actual export prices, the version also restates power purchases to use recent actual import prices. The recalculation of import cost results in a $15.7 million increase in Operating costs.

d) Not confirmed. The use of recent export prices is responsible for $4.8 million of the change in Interest costs, and the modification to imports for the remaining $20.4 million change.

e) The total amount of generation and transmission costs directly assigned to the SEP customers does not change between versions, however, the relative breakdown of the total costs will change. Please see Manitoba Hydro's response to COALITION/MH I-20.

f) The revised version of MIPUG MFR 4 is being provided as an attachment to this response, and includes the following modifications:
   a. US Interconnections classified as Demand and allocated using 2-CP
   b. Dorsey convertor stations functionalized as Transmission
   c. Weighted energy allocator that does not incorporate explicit capacity component

g) An excel model of PCOSS14-Amended that reflects these changes is provided as an attachment to this response.

h) The table below, similar to that provided in MIPUG MFR 6, does not reflect the treatment of radial transmission or other methodologies raised by stakeholders in this proceeding and not directed in Order 116/08.

Order 116/08	PCOSS14 (Amended)	Rationale	Page Ref
As recommended by MH, Transmission costs are to be allocated on the basis of demand for both domestic and export classes rather than energy. (117/06 pg 47)	US Interconnections allocated on the basis of weighted energy.	Dec 4, 2015 COS Submission	Pg 21
Use actual energy (SEP) prices in Generation energy weighting process (116/08 pg 350)	Incorporates explicit capacity adder into on-peak weights	Dec 4, 2015 COS Submission	Pg 20
117/06 and 116/08 are silent on the functionalization of Dorsey converter station. However Order 7/03 (page 98) encourages a further consideration of the treatment of Dorsey	Dorsey converter station functionalized as Generation	Dec 4, 2015 COS Submission	Pg 20

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY-116/08
FOR FISCAL YEAR ENDING
MARCH 31, 2014

TABLE OF CONTENTS

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY-116/08
FOR FISCAL YEAR ENDING
MARCH 31, 2014

Order 116/08 Version of PCOSS14

The attached Cost of Service schedules show the 2013/14 Prospective Cost of Service Study ("PCOSS14") with modifications directed in Order 116/08. The directed modifications include:

- Assign 100% of "trading desk" and MAPP/MISO costs to the export class
- Assign all fuel costs and 50% of fixed thermal generation costs to the export class
- Assign DSM costs directly to the export class and add DSM energy savings to domestic load for generation allocation purposes
- Use most recent forecast export prices to establish export revenue
- Use actual eight year SEP prices and energy use profiles for generation weighting

Net Export Revenue

The modifications directed in Order 116/08 result in negative net export revenue of $146 million to be allocated to domestic customers. A summary of the costs assigned or allocated to the Export class is shown in the table below.

	PCOSS14 116/08 ($ Million)
Gross Export Revenue	340
Less:	
Uniform Rates	23
Affordable Energy Fund	13
DSM	40
Trading Desk	13
MISO/NEB	5
Purchased Power	171
Thermal Costs	33
Allocated Generation	147
Allocated Transmission	42
Net Export Revenue	(146)

The primary tables presented below are based on PCOSS14-116/08 methodology.

1. Revenue Cost Coverage Table (Schedule B1-116/08) - This ratio compares revenues of each class to its allocated costs. The RCC ratio provides the relative performance of each rate class over a base of 100%.

2. Customer, Demand and Energy Costs (Schedule B2-116/08) - In this table the components are converted to unit costs using billing determinants, i.e., number of customers, billable demand and kWh sales. The information in Schedule B2 is intended to provide a comparison of allocated unit costs with the corresponding price in the appropriate rate schedule.

3. Functional Breakdown (Schedule B3-116/08) - This table identifies the cost of providing each level of service to each customer class.

4. Classified Costs by Allocation (Schedule E1-116/08) - This table summarizes the classified costs by allocation table.

SCHEDULE B1-116/08
Revenue Cost Coverage Analysis

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014 - 116/08
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	551,118	588,630	(64,735)	523,895	95.1%
General Service - Small Non Demand	114,376	135,035	(13,435)	121,600	106.3%
General Service - Small Demand	115,633	136,080	(13,582)	122,498	105.9%
General Service - Medium	166,776	186,797	(19,590)	167,207	100.3%
General Service - Large 0 - 30kV	82,922	84,956	(9,740)	75,216	90.7%
General Service - Large 30-100kV*	46,513	57,808	(5,463)	52,344	112.5%
General Service - Large >100kV*	150,925	189,258	(17,728)	171,530	113.7%
*Includes Curtailment Customers					
SEP	967	826	-	826	85.5%
Area & Roadway Lighting	22,229	21,630	(827)	20,802	93.6%
Total General Consumers	1,251,459	1,401,019	(145,101)	1,255,918	100.4%
Diesel	9,908	6,612	(1,164)	5,448	55.0%
Export	486,718	340,454	146,264	486,718	100.0%
Total System	1,748,084	1,748,084	-	1,748,084	100.0%

SCHEDULE B2-116/08
Customer, Demand, Energy Cost Analysis

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014 - 116/08
Customer, Demand, Energy Cost Analysis

SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy mWh	ENERGY Unit Cost ¢/kWh
Residential	142,825	486,987	24.44	224,802	0%	n/a	n/a	248,227	7,404,453	6.39 **
GS Small - Non Demand	28,515	53,778	44.19	44,610	0%	n/a	n/a	54,686	1,605,511	6.18 **
GS Small - Demand	9,684	12,492	64.60	51,528	38%	2,390	8.17	68,003	2,047,715	4.88
General Service - Medium	8,498	1,974	358.73	73,880	87%	7,302	8.84	103,988	3,174,662	3.57
General Service - Large <30kV	4,288	288	n/a	34,258	100%	4,042	9.54 *	54,117	1,702,481	3.18
General Service - Large 30-100kV	2,957	40	n/a	11,644	100%	2,894	5.04 *	37,375	1,327,210	2.82
General Service - Large >100kV	2,732	16	n/a	27,352	100%	8,409	3.58 *	138,569	4,903,742	2.83
SEP	325	29	933.74	133	0%	n/a	n/a	509	26,500	2.42 **
Area & Roadway Lighting	16,657	155,024	8.95	3,100	0%	n/a	n/a	3,299	100,487	6.37 **
Total General Consumers	216,481	710,628		471,305		25,038		708,773	22,292,761	
Diesel	261	755	28.84	392	0%	n/a	n/a	10,418	13,754	78.59 **
Export	n/a	n/a	n/a	45,704	0%	n/a	n/a	441,014	9,013,000	5.40 ***
Total System	216,742	711,383		517,402		25,038		1,160,205	31,319,515	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

SCHEDULE B3-116/08
Functional Breakdown

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014 - 116/08
Functional Breakdown

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	615,853	248,227	40.3%	67,417	10.9%	40,075	6.5%	79,351	12.9%	180,784	29.4%
General Service - Small Non Demand	127,811	54,686	42.8%	15,110	11.8%	7,512	5.9%	20,166	15.8%	30,338	23.7%
General Service - Small Demand	129,215	68,003	52.6%	17,702	13.7%	8,613	6.7%	4,819	3.7%	30,078	23.3%
General Service - Medium	186,365	103,988	55.8%	26,902	14.4%	11,962	6.4%	7,334	3.9%	36,179	19.4%
General Service - Large <30kV	92,662	54,117	58.4%	13,564	14.6%	5,930	6.4%	4,023	4.3%	15,029	16.2%
General Service - Large 30-100kV	51,976	37,375	71.9%	7,450	14.3%	4,194	8.1%	2,878	5.5%	79	0.2%
General Service - Large >100kV	168,653	138,569	82.2%	27,352	16.2%	0	0.0%	2,700	1.6%	33	0.0%
SEP	967	509	52.7%	133	13.7%	0	0.0%	308	31.9%	17	1.7%
Area & Roadway Lighting	23,056	3,062	13.3%	523	2.3%	599	2.6%	566	2.5%	18,305	79.4%
Total General Consumers	1,396,559	708,536	50.7%	176,152	12.6%	78,885	5.6%	122,146	8.7%	310,841	22.3%
Diesel	11,071	10,418	94.1%	0	0.0%	0	0.0%	0	0.0%	653	5.9%
Export	486,718	441,014	90.6%	45,704	9.4%	0	0.0%	0	0.0%	0	0.0%
Total System	1,894,349	1,159,968	61.2%	221,856	11.7%	78,885	4.2%	122,146	6.4%	311,494	16.4%

SCHEDULE E1-116/08
Classified Costs by Allocation Table
PAGE 1 OF 2

Prospective Cost Of Service Study
March 31, 2014 - 116/08
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Domestic & Dependable Export		297,621	177,238	306,061	-	780,920
E13	Generation - Domestic & Export		-	-	-	-	-
E14	TBD						-
			297,621	177,238	306,061	-	780,920
E15	Transmission - Weighted Energy		-	-	-	-	-
D13	Transmission - 2CP Domestic			-			-
D14	Transmission - 2CP Domestic & Export		66,426	63,449	69,311	-	199,186
			66,426	63,449	69,311	-	199,186
D21	Subtrans		5,183	21,833	25,025		52,042
D22	Subtrans	Stations	9,441	-			9,441
D23	Subtrans	Line	9,152	-			9,152
			23,776	21,833	25,025	-	70,634
D32	Dist. Plant Stn		20,949	26,313	36,101		83,362
D36	Dist. Plant	Lines	34,376	25,885	22,897		83,158
D40	Dist. Plant	S/E	10,840	11,974	4,125		26,938
			66,165	64,171	63,123	-	193,458
C23	Dist. Plant	Lines	22,918	17,256	15,265		55,438
C27	Dist. Plant	Services	3,032	2,283	2,019		7,334
C40	Dist. Plant	Meter Investment	1,635	4,197			5,833
C41	Dist. Plant	Meter Mtce.			2,188		2,188
			27,585	23,736	19,472	-	70,792
C10	Dist Serv	Cust Service - General	2,238	5,570	38,661	-	46,469
C11	Dist Serv	Cust Acct - Billings	1,398	2,607	24,147		28,153
C12	Dist Serv	Cust Acct - Collections	919	1,413	15,873		18,205
C13	Dist Serv	Marketing - R & D	40	53	690		783
C14	Dist Serv	Inspection	179	546	3,092		3,817
C15	Dist Serv	Meter Read	606	879	10,467		11,951
			5,381	11,068	92,929	-	109,378
	Total Allocated Costs		486,953	361,496	575,921	-	1,424,369

SCHEDULE E1-116/08
Classified Costs by Allocation Table
PAGE 2 OF 2

DIRECTS

C02	Generation	Diesel	952	1,566	6,804		9,323
E01	Generation	Export	36,538	53,726	203,645		293,909
			36,538	53,726	203,645	-	293,909
E01	Generation	SEP - GSM	179	118	174		470
E01	Generation	SEP - GSL 0-30kV	15	10	15		39
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential					-
E01	Generation	GSS ND					-
E01	Generation	GSS Demand					-
E01	Generation	GSM					-
E01	Generation	GSL 0-30kV					-
E01	Generation	GSL 30-100kV excl Curt.					-
E01	Generation	GSL >100kV excl Curt.					-
E01	Generation	Street Lights					-
E01	Generation	Curtailment (GSL 30-100)					-
E01	Generation	Curtailment (GSL > 100)					-
			194	128	188	-	509
D04	Transmission	Export	-	-	4,071		4,071
D04	Transmission	SEP - GSM	41	39	42		122
D04	Transmission	SEP - GSL 0-30kV	3	3	4		10
			45	42	46	-	133
C01	Distribution	Lighting	3,409	3,926	7,850		15,185
C01	Distribution	Diesel	56	85	444		585
			3,465	4,011	8,294	-	15,770
	Total Directs		41,194	59,472	223,048	-	323,715
	Total		528,147	420,968	798,969	-	1,748,084
	Generation		335,305	232,658	516,699	-	1,084,661
	Transmission		66,470	63,491	73,428	-	203,390
	Subtransmission		23,776	21,833	25,025	-	70,634
	Distribution Plant		97,215	91,918	90,888	-	280,021
	Distribution Services		5,381	11,068	92,929	-	109,378
			528,147	420,968	798,969	-	1,748,084
	Energy		334,353	231,091	509,894	-	1,075,338
	Demand		156,411	149,495	161,576	-	467,483
	Customer		37,383	40,381	127,499	-	205,263
			528,147.04	420,968.00	798,969.40	-	1,748,084

Section:	MIPUG MFR 5 PUB MFR 13	Page No.:	
Topic:	Cost of Service Study		
Subtopic:	PCOSS14-Amended		
Issue:	Impact of Compliance with Board Directives		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The tables provided in MIPUG MFR 5 do not include the impact of either: i) the proposed change in functionalization and classification/allocation of Dorsey (Generation as opposed to Transmission), ii) the proposed change in the classification/allocation of Interconnections (Weighted Energy as opposed to 2CP Demand) or iii) the explicit inclusion of capacity costs in the weighted energy allocator. Please revise MIPUG MFR 5 to include these three items.

RATIONALE FOR QUESTION:

To understand the impact of the proposed changes to the COSS methodology.

RESPONSE:

Please see the table below.

Impact of Methodology Change on Class RCC

Customer Class	PCOSS14 Amended	Weighted Energy Allocator	Inter-connections	Dorsey 100% Transmission	Secondary to GSL 0-30	Radial Trans as Subtrans	Purchased Power to Export	Trading desk and MISO to Export	Coal Gen to Export	NG Gen to Export	Wind to Export	DSM to Export	One Export Class	Actual Exports / Imports	Total Impact on RCC	PCOSS14 116/08
Residential	99.8%	-0.1%	0.0%	-0.3%	0.2%	-0.1%	-0.8%	-0.2%	-0.2%	-0.2%	-0.9%	-1.2%	-0.8%	-0.1%	-4.7%	95.1%
General Service - Small Non Demand	108.0%	0.3%	0.0%	-0.3%	0.2%	-0.1%	-0.3%	-0.1%	0.0%	-0.1%	-0.4%	-0.6%	-0.3%	0.0%	-1.7%	106.3%
General Service - Small Demand	104.5%	0.2%	0.0%	-0.1%	0.2%	-0.1%	0.3%	0.1%	0.1%	0.1%	0.3%	-0.2%	0.4%	0.1%	1.4%	105.9%
General Service - Medium	99.4%	0.3%	0.0%	-0.1%	0.2%	0.0%	0.3%	0.1%	0.1%	0.1%	0.4%	-1.0%	0.4%	0.1%	0.9%	100.3%
General Service - Large 0 - 30kV	91.3%	0.4%	0.0%	0.0%	-1.6%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.3%	0.2%	-0.1%	-0.6%	90.7%
General Service - Large 30-100kV	100.0%	-0.4%	0.1%	0.6%	0.0%	-0.1%	1.4%	0.3%	0.4%	0.4%	1.7%	6.3%	1.6%	0.2%	12.5%	112.5%
General Service - Large >100kV	98.6%	-0.4%	0.1%	0.8%	0.0%	0.6%	2.0%	0.4%	0.6%	0.6%	2.4%	5.3%	2.3%	0.4%	15.1%	113.7%
Area & Roadway Lighting	100.2%	-0.6%	0.0%	0.3%	0.1%	-0.2%	-0.2%	-0.1%	-0.1%	0.0%	-0.3%	-5.7%	-0.4%	0.6%	-6.6%	93.6%

Impact of Methodology Change on Variance from Unity (Total Cost - Total Revenue) ($ thousands)

Customer Class	PCOSS14 Amended	Weighted Energy Allocator	Inter-connections	Dorsey 100% Transmission	Secondary to GSL 0-30	Radial Trans as Subtrans	Purchased Power to Export	Trading desk and MISO to Export	Coal Gen to Export	NG Gen to Export	Wind to Export	DSM to Export	One Export Class	Actual Exports / Imports	Total Impact on RCC	PCOSS14 116/08
Residential	(1,404)	(487)	(119)	(1,541)	1,047	(844)	(4,890)	(965)	(1,193)	(1,248)	(4,805)	(6,731)	(3,683)	(359)	(25,819)	(27,224)
General Service - Small Non Demand	10,587	358	(23)	(304)	188	(70)	(758)	(145)	(185)	(193)	(744)	(840)	(517)	(130)	(3,363)	7,223
General Service - Small Demand	6,228	269	(9)	(116)	216	(76)	158	41	39	40	155	(361)	233	48	638	6,865
General Service - Medium	(1,155)	643	(14)	(184)	299	(14)	664	156	162	170	654	(1,756)	715	93	1,587	432
General Service - Large 0 - 30kV	(8,692)	451	(2)	(32)	(1,764)	8	507	112	124	129	498	445	470	41	986	(7,706)
General Service - Large 30-100kV	2	(241)	30	390	(0)	(67)	828	155	202	211	814	2,953	520	32	5,829	5,831
General Service - Large >100kV	(2,766)	(860)	133	1,718	(0)	1,085	3,953	751	964	1,009	3,883	7,786	2,705	244	23,370	20,604
Area & Roadway Lighting	53	(138)	5	61	14	(28)	(57)	(16)	(14)	(15)	(56)	(1,299)	(75)	139	(1,479)	(1,427)

Section:	Submission Appendix 3.1	**Page No.:**	Page 11 Pages 48 & 68-69
Topic:	Allocation		
Subtopic:	Transmission		
Issue:	Use of 2CP Allocator		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Based on the 2011/12 Load Research data please provide the monthly 1-hour coincident peak values, showing the contribution of both domestic load and exports to the overall CP value in each month.

RATIONALE FOR QUESTION:

To understand the basis for using the 2CP allocator for Transmission.

RESPONSE:

Please see the attachment to this response which lists the monthly 1-hour coincident peak kW demands for domestic load and exports corresponding to 2011/2012 Load Research at generation.

Load Research Results 2011/2012
12 Monthly Generation CP (kW)
During Peak Hours (06:00 to 22:00)

	2011-04-13 9:00	2011-05-13 11:00	2011-06-29 19:00	2011-07-21 15:00	2011-08-16 14:00	2011-09-01 15:00
Generation	4,657,196	4,706,150	4,885,921	4,962,924	4,791,723	4,527,144
Exports	1,447,000	1,670,000	1,778,000	1,940,000	1,868,000	1,697,000
GS Large 30 - 100 kV	95,514	101,487	107,637	110,120	114,768	117,353
GS Large 30 - 100 kV Curtailable	25,615	25,649	25,350	25,234	25,541	25,031
GS Large > 100 kV	231,530	329,015	282,321	267,694	187,036	238,780
GS Large > 100 kV Curtailable	221,591	211,527	204,804	207,704	219,300	210,108
GS Large 750 V - 30 kV	216,200	214,629	220,442	235,116	237,549	238,744
GS Large 750 V - 30 kV SEP	258	188	380	713	782	777
GS Medium	408,373	389,134	403,420	443,952	439,592	439,796
GS Medium SEP	4,701	2,953	467	537	271	410
GS Small Demand	263,205	242,450	224,390	254,405	258,738	254,932
GS Small Non Demand	223,858	216,493	182,339	233,131	212,167	212,359
Residential	1,003,191	758,826	917,802	703,458	614,647	575,662

	2011-10-27 19:00	2011-11-30 20:00	2011-12-08 18:00	2012-01-11 14:00	2012-02-09 18:00	2012-03-19 20:00
Generation	4,500,450	4,842,683	4,838,358	4,937,215	4,886,393	4,894,981
Exports	1,418,000	1,186,000	707,000	1,082,000	887,000	2,006,000
GS Large 30 - 100 kV	110,629	136,305	109,317	130,648	142,282	108,369
GS Large 30 - 100 kV Curtailable	24,884	24,537	21,658	24,483	24,672	25,027
GS Large > 100 kV	343,449	370,631	366,389	336,413	336,504	293,373
GS Large > 100 kV Curtailable	206,281	217,917	197,967	204,689	192,872	213,059
GS Large 750 V - 30 kV	205,492	211,869	229,362	240,318	223,731	212,022
GS Large 750 V - 30 kV SEP	118	224	163	90	78	42
GS Medium	376,632	412,384	461,976	472,982	451,939	370,649
GS Medium SEP	2,145	4,483	5,581	5,077	5,683	3,060
GS Small Demand	227,552	268,759	311,006	330,964	302,351	219,717
GS Small Non Demand	174,389	225,119	260,314	286,118	266,108	147,693
Residential	910,057	1,230,319	1,435,596	1,134,643	1,422,083	805,304

Section:	Submission Appendix 3.1	**Page No.:**	Page 11 Pages 48 & 68-69
Topic:	Allocation		
Subtopic:	Transmission		
Issue:	Use of 2CP Allocator		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) What would be the allocation factor for each customer class based a 12CP allocator?

RATIONALE FOR QUESTION:

To understand the basis for using the 2CP allocator for Transmission.

RESPONSE:

The 12CP allocators, based on the 2011/12 Load Research data in COALITION/MH I-87a, are provided in the tables below. Given that the Area and Roadway Lighting class was not included in 2011/12 Load Research, their 12CP is estimated based on whether the streetlights would have been on at the monthly peak. The analysis indicated the streetlights would be expected to be on at the time of October, November, December, February and March peaks.

Prospective Cost Of Service Study
12CP Forecast Demand (Domestic, Dependable)

		Curtailable Class	Class	Total
Residential	Standard & All Electric		1,212.4	1,212.4
	Seasonal		7.2	7.2
	Water Heating		1.5	1.5
Total Residential		0.0	1,221.0	1,221.0
General Service Small:	Non-Demand		267.9	267.9
	Demand		325.0	325.0
	Seasonal		0.4	0.4
	Water Heating		0.6	0.6
Total General Service Small		0.0	594.0	594.0
SEP	GSM			0.0
	GSL			0.0
Total SEP		0.0	0.0	0.0
General Service Medium			508.5	508.5
General Service Large	0-30KV		270.4	270.4
	30-100KV	29.1	149.5	178.6
	>100KV	261.9	359.3	621.2
Total General Service Large		291.0	779.1	1,070.1
Area & Roadway Lighting			12.3	12.3
Total General Consumers		291.0	3,114.9	3,405.9
Diesel				0.0
Export			667.1	667.1
Total System		291.0	3,782.0	4,073.0

Prospective Cost Of Service Study
12CP Forecast Demand (Domestic, Dependable)

		Curtailable Class	Class	Total
Residential	Standard & All Electric		29.8%	29.8%
	Seasonal		0.2%	0.2%
	Water Heating		0.0%	0.0%
Total Residential			30.0%	30.0%
General Service Small:	Non-Demand		6.6%	6.6%
	Demand		8.0%	8.0%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small			14.6%	14.6%
SEP	GSM		0.0%	0.0%
	GSL		0.0%	0.0%
Total SEP			0.0%	0.0%
General Service Medium			12.5%	12.5%
General Service Large	0-30KV		6.6%	6.6%
	30-100KV	0.7%	3.7%	4.4%
	>100KV	6.4%	8.8%	15.3%
Total General Service Large		7.1%	19.1%	26.3%
Area & Roadway Lighting			0.3%	0.3%
Total General Consumers		7.1%	76.5%	83.6%
Diesel			0.0%	0.0%
Export			16.4%	16.4%
Total System		7.1%	92.9%	100.0%

Section:	Appendix 3 2005 COSS Methodology Review RCM/TREE/MH I-17	**Page No.:**	Schedule E1-Amended
Topic:	Reconciliation of Financial Forecast		
Subtopic:	O&A Costs		
Issue:	DSM		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The response to the referenced RCM/TREE interrogatory indicated that DSM costs are all capital related. However, Appendix 3, Schedule E1-Amended indicates there are Operating costs associated with DSM. Please reconcile and explain what the DSM operating costs in PCOSS14-Amended are for.

RATIONALE FOR QUESTION:

To understand the costs directly assigned as DSM.

RESPONSE:

The response to RCM/TREE/MH I-17 would not have included operating costs related to DSM programs as prior to Manitoba Hydro's 2009/10 fiscal year, Manitoba Hydro recognized <u>all</u> electric DSM program expenditures as deferred costs that were amortized over a period of 15 years. In fiscal year 2009/10, Manitoba Hydro implemented changes to its accounting treatment of DSM costs such that DSM program costs for research, general promotion, and promotional activities to introduce new programs are now expensed as incurred. These annual DSM expenditures represent the operating charges in the PCOSS14-Amended.

Section:	Appendix 1 2005 COSS Methodology Review PUB/ MH I-14 a)	**Page No.:**	Page 3
Topic:	Export Class		
Subtopic:	Dependable versus Opportunity Exports		
Issue:	Basis for Dependable/Export Split		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Has the basis for splitting Export kWh between Dependable and Opportunity exports changed from that used in the 2005 COSS proposal?

b) If yes, please explain what the change is and why it was made.

RATIONALE FOR QUESTION:

To understand the proposed split between dependable and opportunity exports.

RESPONSE:

Please see the response to COALITION/MH I-21e.

Section:	Submission Appendix 3	Page No.:	Page 17 Pages 5-7
Topic:	Cost of Service Study		
Subtopic:	PCOSS14-Amended		
Issue:	Comparative Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that, based on PCOSS14-Amended, compares all the costs assigned to GS>100 non-curtailable, GS>100 curtailable, dependable exports, opportunity exports, and SEP GSL 0-30 broken down by function (Generation, Transmission, Subtransmission, Distribution Plant, Distribution Service and Total) expressed in both total dollars and cents/kWh. Note: Please provide the results both before and after the allocation of Net Export revenues.

RATIONALE FOR QUESTION:

To compare the overall COSS results for different classes of customers.

RESPONSE:

PCOSS14-Amended Costs Before Net Export Revenue

Class	Total ($000)	Generation ($000)	Transmission ($000)	Distribution Cust Service ($000)	Distribution Plant ($000)
GSL>100kV Curtailable	86,661	77,035	8,964	659	4
GSL>100kV Non Curtailable	117,877	103,233	12,856	1,762	26
SEP GSL 0-30 kV	107	39	10	53	4
Dependable Export	187,107	165,660	21,447	n/a	n/a
Opportunity Export	30,651	30,175	476	n/a	n/a

(AEF and URA are excluded. AEF and URA are treated as a reduction of NER, not a cost of exports)

PCOSS14-Amended Costs After Net Export Revenue

Class	Total ($000)	Generation ($000)	Transmission ($000)	Distribution Cust Service ($000)	Distribution Plant ($000)
GSL>100kV Curtailable	81,450	72,430	8,400	617	3
GSL>100kV Non Curtailable	110,573	96,851	12,047	1,651	24
SEP GSL 0-30 kV	107	39	10	53	4
Dependable Export	187,107	165,660	21,447	n/a	n/a
Opportunity Export	30,651	30,175	476	n/a	n/a

(AEF and URA are excluded. AEF and URA are treated as a reduction of NER, not a cost of exports)

PCOSS14-Amended Unit Costs Before Net Export Revenue

Class	Metered Energy MWh	Total (¢/kWh)	Generation (¢/kWh)	Transmission (¢/kWh)	Distribution Cust Service (¢/kWh)	Distribution Plant (¢/kWh)
GSL>100kV Curtailable	2,062,959	4.20	3.73	0.43	0.03	0.00
GSL>100kV Non Curtailable	2,840,783	4.15	3.63	0.45	0.06	0.00
SEP GSL 0-30 kV	2,000	5.35	1.96	0.51	2.67	0.21
Dependable Export	4,592,000	4.08	3.61	0.47	n/a	n/a
Opportunity Export	4,421,000	0.69	0.68	0.01	n/a	n/a

(AEF and URA are excluded. AEF and URA are treated as a reduction of NER, not a cost of exports)

PCOSS14-Amended Unit Costs After Net Export Revenue

Class	Metered Energy MWh	Total (¢/kWh)	Generation (¢/kWh)	Transmission (¢/kWh)	Distribution Cust Service (¢/kWh)	Distribution Plant (¢/kWh)
GSL>100kV Curtailable	2,062,959	3.95	3.51	0.41	0.03	0.00
GSL>100kV Non Curtailable	2,840,783	3.89	3.41	0.42	0.06	0.00
SEP GSL 0-30 kV	2,000	5.35	1.96	0.51	2.67	0.21
Dependable Export	4,592,000	4.08	3.61	0.47	n/a	n/a
Opportunity Export	4,421,000	0.69	0.68	0.01	n/a	n/a

(AEF and URA are excluded. AEF and URA are treated as a reduction of NER, not a cost of exports)

Section:	Submission Appendix 3.1 Appendix 3	**Page No.:**	Pages 14-17 Page 11 Page 2
Topic:	Functionalization		
Subtopic:	Export Costs		
Issue:	Treatment of Transmission Service Costs		

PREAMBLE TO IR (IF ANY):

It is understood that Manitoba Hydro uses Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) when exporting from the province of Manitoba and Transmission Service from the MISO and other Transmission Providers' applicable OATTs is utilized from the Manitoba border to the applicable delivery point (per 2005 COSS Review, CAC/MSOS/MH I-16 d).

QUESTION:

a) What costs for such Transmission Services are included in IFF12 for 2013/`14 and where are such Transmission costs included in the PCOSS14-Amended (e.g., are these charges included in the Transmission function costs or are they netted out of the Export Revenues reported)?

b) Has this treatment changed from that in PCOSS14? If so, how?

c) If the costs include Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) where are the revenues back to Manitoba Hydro reflected in the COSS and are these revenues equivalent to the charges paid under Manitoba Hydro's OATT?

RATIONALE FOR QUESTION:

To understand the transmission service and treatment of transmission service costs associated with Exports.

RESPONSE:

In PCOSS14-Amended the costs of Transmission Service are included as part of Purchased Power costs, and are allocated to domestic and all export load via the Generation pool. In PCOSS14 the cost of Purchased Power, including the Transmission Service fee, was directly assigned to Exports.

Export revenue in PCOSS14 includes the gross amount of Tariff Revenues received by Manitoba Hydro including those paid by external parties for use of Manitoba Hydro transmission.

Section:	Submission Appendix 3.1 Appendix 3	**Page No.:**	Pages 14-17 Page 11 Page 2
Topic:	Functionalization		
Subtopic:	Export Costs		
Issue:	Treatment of Transmission Service Costs		

PREAMBLE TO IR (IF ANY):

It is understood that Manitoba Hydro uses Transmission Service under Manitoba Hydro's Open Access Transmission Tariff (OATT) when exporting from the province of Manitoba and Transmission Service from the MISO and other Transmission Providers' applicable OATTs is utilized from the Manitoba border to the applicable delivery point (per 2005 COSS Review, CAC/MSOS/MH I-16 d).

QUESTION:

d) At the time of IFF12, had either Manitoba Hydro or any other party applied for/contracted for long-term (>1 year) firm use of Manitoba Hydro's Transmission facilities for power to be exported from Manitoba in 2013/14 under Manitoba Hydro's OATT? If yes, please indicate the nature of the contracts applied for/in place (in terms of the type of contract and the MWs and months of the year involved).

e) Currently, has either Manitoba Hydro or any other party applied for/contracted for long term (>1 year) firm use of Manitoba Hydro's Transmission facilities for power to be exported from Manitoba under Manitoba Hydro's OATT? If yes, please indicate the nature of the contracts applied for/in place (in terms of the type of contract and the MWs and months of the year involved).

RATIONALE FOR QUESTION:

To understand the transmission service and treatment of transmission service costs associated with Exports.

RESPONSE:

d) Manitoba Hydro's Transmission Business Unit confirms that, pursuant to Manitoba Hydro's current business practices, only Manitoba Hydro Marketing is permitted to contract for long-term firm use of Manitoba Hydro's transmission facilities for power to be exported from Manitoba.

Manitoba Hydro Marketing confirms that it contracted for certain Long Term Firm Point to Point transmission service reservations (TSRs) under the Manitoba Hydro OATT for power to be exported in 2013/14 as indicated in the attached table, which is organized according to delivery point.

Manitoba Hydro Marketing confirms that it had not applied for any additional long-term (>1 year) firm service of Manitoba Hydro's transmission facilities for power to be exported in 2013/14 under the Manitoba Hydro OATT.

Delivery Point: MISO		
TSR	**Existing 2013/14 MW**	**Months of year**
1	529	All
2	213	All
3	200	May 1-October 31
4	150	May 1-October 31
5	150	May 1-October 31
6	100	All
7	100	All
8	100	All
9	64	All
10	55	All
11	50	All
12	50	All
13	50	All
14	30	All
15	7	All
Total MW	**1848**	
Delivery Point: Saskatchewan		
TSR	**Existing 2013/14 MW**	**Months of year**
1	45	All
Total MW	**45**	
Delivery Point: Ontario		
TSR	**Existing 2013/14 MW**	**Months of year**
1	100	All
2	100	All
Total MW	**200**	

e) Yes, Manitoba Hydro Marketing can confirm that it has applied and contracted for certain Long Term Firm Point to Point transmission service reservations (TSRs) under the Manitoba Hydro OATT for power to be exported as indicated in the attached table, which is organized according to delivery point.

Delivery Point: MISO					
TSR	**Existing 2016/17 MW**	**Future Contract MW**	**Future Applied MW**	**Start Date**	**Months of year**
1	529				All
2	213				All
3	200				All starting May 1, 2016
4	150				All
5	150				All
6	100				All
7	100				All
8	100				All
9	64				All
10	55				All
11	50				All
12	50				All
13	50				All
14	30				All
15	7				All
16		500		June 1, 2020*	All
17		250		June 1, 2020*	All
18		133		June 1, 2020*	All
Total MW	**1848**	**883**	**0**		
Delivery Point: Saskatchewan					
TSR	**Existing 2016/17 MW**	**Future Contract MW**	**Future Applied MW**	**Start Date**	**Months of year**
1	45				All
2	25				All
3		45		June 1, 2020	All
4			100	June 1, 2020**	All
5			20	June 1, 2020**	All
6			20	June 1, 2020**	All
Total MW	**70**	**45**	**140**		
Delivery Point: Ontario					
TSR	**Existing 2016/17 MW**	**Future Contract MW**	**Future Applied MW**	**Start Date**	**Months of year**
1	100				All
Total MW	**100**	**0**	**0**		

*TSRs will commence on the Manitoba Minnesota Transmission Project in service date.

**Applications are related to a specific executed sale; TSRs are currently being studied.

Section:	Submission PCOSS14- Amended Model	**Page No.:**	Page 21 Allocated Costs Tab
Topic:	Classification/Allocation		
Subtopic:	Transmission		
Issue:	Interconnections - Cost		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Do the costs of the US Interface attributed to Interconnections in the PCOSS14-Amended model (Allocated Costs Tab) include just the operating and depreciation cost directly associated with facilities and use just the directly associated asset costs for purposes of allocating interest, or do they also include a share of operating costs, depreciation costs and assets that are considered to be common transmission costs?

RATIONALE FOR QUESTION:

To understand the costs attributed to Interconnections.

RESPONSE:

The cost of the US Interface as provided does not include a share of common transmission costs.

Section:	2005 COSS Review, CAC/ MSOS/MH II-23 a) PCOSS14-Amended Model C Tables & D Tables Tabs	Page No.:	
Topic:	Allocation		
Subtopic:	GSS Classes		
Issue:	Customer Counts Used		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether, for PCOSS14-Amended, (non-ARL) non-metered accounts are included in GSS Non-Demand. If not, where are they reflected in the COSS?

b) Please confirm whether Customer Counts (Allocation Table C90) and the Demand allocators for this class include the number and load for these non- metered accounts.

c) There does not appear to be any adjustment to the GSS-ND customer counts used for the allocation of Meter Reading costs, Meter Maintenance cost or Meter Assets to account for the un-metered accounts. Please explain why.

d) The calculation of the Weighted Customer Count values for GSS-ND and GSS- Demand used for Meter Reading (Allocation Table C15) does not appear to include any three-phase customers. Please explain.

RATIONALE FOR QUESTION:

To understand the determination of the customer weighted allocation factors for the GSS sub-classes.

RESPONSE:

a) Confirmed.

b) Confirmed.

c) The GSS Non-Demand customer count used in the allocation of Meter related costs is overstated by 1.2% due to the 649 non-metered accounts that have been included. However, given the dollars involved, there is no impact on RCCs by incorporating the revised customer count in PCOSS14-Amended.

d) The GSS Non-Demand and GSS Demand customer count for Meter Reading inadvertently excluded three-phase customers. The RCC for GSS Non-Demand decreases 0.2% and GSS Demand decreases 0.3% with the inclusion of three-phase customers.

Section:	2002 Status Update, CAC/ MSOS/MH I-9.1 d) and CAC/MSOS/MH II-43	Page No.:	
Topic:	Functionalization		
Subtopic:	Ancillary Services		
Issue:	Generation and Transmission Assets Included		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether the above referenced responses provided during the 2002 Status Update are still correct. If not, please provide revised responses.

RATIONALE FOR QUESTION:

To understand the costs included in Ancillary Services.

RESPONSE:

Confirmed. Please find attached the responses to CAC/MSOS/MH I-9.1d) and CAC/MSOS/MH II-43 filed during the 2001 Status Update.

CAC/MSOS/MH I-9.1

Subject: **Cost of Service Revisions - Functionalization**
Reference: **Section J, p. 127 and Appendix 12, p. 27 and Schedule D5**

QUESTION:

d) **Please breakdown the Ancillary Services function's costs according the the six services listed on p. 42 and, for each service, indicate whether the costs were originally bundled with Generation or Transmission costs and how they were unbundled?**

ANSWER:

Ancillary service rates are derived by calculating a "revenue requirement" for each service and dividing it by the appropriate billing determinant or load share to come up with the rate. Assets are identified that would be used in the provision of the particular ancillary service and their associated costs are used in the calculation of the revenue requirement. There is no "unbundling" per se, but in the case of Schedule 1, Scheduling, System Control and Dispatch Service, some of the identified costs are bundled in the Transmission and Communication costs. These costs are identified and unbundled from Transmission so that they are recovered through the ancillary service charge and not through the Transmission Tariff.

Schedule 1: Scheduling, System Control and Dispatch Service

The following assets have their transmission system component identified in the revenue requirement calculation for this ancillary service; communications, instrumentation, monitoring and control and SCADA. The identified costs were originally bundled with Transmission and Communication.

Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service

The components of the Generating Facilities assets that are needed to produce (or absorb) reactive power component are identified in the revenue requirement calculation for this ancillary service. The identified costs were originally bundled with Generation.

Note: The revenue requirement for the control of reactive power generation (or absorption) from transmission equipment (for example capacitors and reactors) is included in the charges for basic point-to-point and network transmission services.

Schedule 3: Regulation and Frequency Response Service

Manitoba Hydro currently operates with Grand Rapids Generating Station and the HVDC system on AGC control and these two resources provide the Regulation and Frequency Response Ancillary Service. A percentage of both Grand Rapids Generating Station assets and the HVDC system assets are identified in the revenue requirement calculation for this ancillary service. The identified costs were originally bundled with Generation.

Schedule 4: Energy Imbalance Service

Energy Imbalance Service is based on an energy charge and there are no assets per se associated with this ancillary service.

Schedule 5: Operating Reserve - Spinning Reserve Service

Manitoba Hydro currently operates with Grand Rapids Generating Station and the HVDC system on AGC control and these two resources provide the Spinning Reserve Ancillary Service. A percentage of both Grand Rapids Generating Station assets and the HVDC system assets are identified in the revenue requirement calculation for this ancillary service. The identified costs were originally bundled with Generation.

Schedule 6: Operating Reserve - Supplemental Reserve Service

A percentage of all Manitoba Hydro hydraulic generation assets are identified in the revenue requirement calculation for the Supplemental Reserve Ancillary Service with the exception of the following:

- Kelsey - Normally operated at full gate due to inflows usually exceeding plant capacity.
- Laurie River - Unstaffed with no RTU and has no way of deploying "reserves".
- Jenpeg - Generation changes are scheduled in accordance with agreements with the residents.

The identified costs were originally bundled with Generation.

CAC/MSOS/MH II-43

Reference: CAC/MSOS/MH I-9.1 d) and Volume 3, Appendix 12, Scheduled B16

QUESTION:

Please describe how the operating costs associated with each of the six ancillary services were determined.

ANSWER:

In determining the operating costs associated with each ancillary service, the following criteria were followed;

Schedule 1: Scheduling, System Control and Dispatch Service.

Assets that should have the Transmission System component of their revenue requirement recovered through this ancillary service are communications, instrumentation, monitoring and control and SCADA. The appropriate operating costs were allocated to these assets for this ancillary service.

Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service.

The charge for this service is calculated by associating a revenue requirement with the components of the Generating Facilities that are needed to produce (or absorb) reactive power. The appropriate operating costs were allocated to these assets for this ancillary service.

Schedule 3: Regulation and Frequency Response Service.

Manitoba Hydro currently operates with Grand Rapids Generating Station and the HVDC system on automatic generation control (AGC), providing regulation and frequency control. The revenue requirement calculation for this service is based on it being shared equally between these two resources. A percentage of the appropriate operating costs were allocated to these assets for this ancillary service.

Schedule 4: Energy Imbalance Service.

Energy Imbalance Service is based on an energy charge and there are no assets or associated operating costs associated with this ancillary service.

Schedule 5: Operating Reserve - Spinning Reserve Service.

Manitoba Hydro currently operates with Grand Rapids Generating Station and the HVDC system on AGC control and these two resources provide the Spinning Reserve Ancillary Service. The revenue requirement calculation for this service is based on it being shared equally between these two resources. A percentage of the appropriate operating costs were allocated to these assets for this ancillary service.

Schedule 6: Operating Reserve - Supplemental Reserve Service.

It is assumed that all Manitoba Hydro hydraulic generation is shared equally to provide this service with the exception of the following:

Kelsey -	Normally operated at full gate due to inflows usually exceeding plant capacity.
Laurie River -	Unstaffed with no remote terminal unit (RTU) and has no way of deploying reserves≅.
Jenpeg -	Generation changes are scheduled in accordance with agreements with the residents.

The revenue requirement calculation for this service is based on it shared equally between the identified generation resources. A percentage of the appropriate operating costs were allocated to these assets for this ancillary service.

Section:	Appendix 1 Submission	**Page No.:**	Page 6 Page 7
Topic:	Cost of Service Study		
Subtopic:	Goals		
Issue:	Approach to Cost Causation		

PREAMBLE TO IR (IF ANY):

In the main Submission (page 7) Manitoba Hydro states that "cost causation is complex and debate focuses on whether considerations of use or intent of investment better reflects cost causation than a methodology which considers only design parameters and associated costs".

In Appendix 1 (page 6) Manitoba Hydro states that "a cost allocation approach that considers the primary role of the investment is the superior cost causal approach".

QUESTION:

a) With respect to the referenced statement from the main Submission, please explain how considerations of the use/intent of an investment could produce a different view of "cost causation" than a methodology that considers only design parameters and associated costs.

b) In Manitoba Hydro's view would considerations regarding the "use" of an investment necessarily yield the same conclusions with respect to cost causation as considerations regarding the "intent" of an investment?

c) Which of these approaches to cost causation (i.e., use, intent or design) has Manitoba Hydro adopted as the appropriate "focus" for determining cost causation? In responding please indicate how this choice relates to what Manitoba Hydro means by the "primary role of the investment" when it states that "a cost allocation approach that considers the primary role of the investment is the superior cost causal approach".

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's approach to cost causation.

RESPONSE:

Response to parts a), b) and c):

The appropriate approach to cost causation is to examine the overall role the investment plays in meeting the needs of customers. Normally the intent, design and use will produce the same result, properly construed. As an example, HVDC transmission is designed to have capacity to carry northern generation, and as such has a design capacity. The actual cost incurred is a function of the physical size of the conductor. However, it cannot be construed as having a capacity role only, because it is also necessary to facilitate the connection of generation producing low cost energy year round to the rest of the Manitoba Hydro system. Its primary role is to integrate remote generation providing both capacity and energy with the main transmission network, in other words these transmission lines have an energy-related intent.

The referenced statement was intended to mean that design parameters should not be narrowly construed and need to be viewed within the context of the overall role of an asset in serving customers. As an example, the fact that a generating station has a design capacity should not necessarily be taken to mean that the only role of the station is to provide capacity over the peak period.

Section:	Appendix 1 Submission	Page No.:	Pages 4 & 6 Pages 7 & 17
Topic:	Cost of Service Study		
Subtopic:	Goals		
Issue:	Approach to Cost Causation		

PREAMBLE TO IR (IF ANY):

In Appendix 1 (page 6) Manitoba Hydro states that "a cost allocation approach that considers the primary role of the investment is the superior cost causal approach" and uses this as justification for functionalizing Dorsey as 100% Generation. In contrast, in the main Submission, Manitoba Hydro uses the argument that the trading desk, MISO fees and power purchases support all load under some conditions (page 17) to justify allocating the associated costs to all domestic load and all exports. Similarly, in Appendix 1 (page 4) Manitoba Hydro uses the argument that natural gas and wind purchases serve all loads under some conditions to allocate the associated costs to domestic load and dependable exports.

QUESTION:

a) If not addressed in the response to the preceding question, please explain more fully what Manitoba Hydro means by "the primary role of an investment" and why considering the primary role of an investment (or activity) is the superior cost causal approach.

b) Please indicate how Manitoba Hydro's consideration of all the roles played by natural gas-generation, wind, power purchases, the trading desk and MISO fees under the range of potential system conditions is consistent with Manitoba Hydro's assertion that "a cost allocation approach that considers the primary role of the investment is the superior cost causal approach".

c) Please comment on what the COSS treatment (classification and allocation) would be if the "primary role of investment" approach to cost causation was applied to each of the following and (if different from the proposed approach) what the rationale was for not using the treatment indicated by the (superior) primary role approach to cost causation:

i. Trading Desk
ii. MISO fees
iii. Power Purchases
iv. Wind Generation
v. Natural Gas-Fired Generation
vi. Coal-Fired Generation
vii. Cross Border Interconnections
viii. The US Great Northern Transmission Line (proposed future treatment)

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's approach to cost causation.

RESPONSE:

a) Please see the response to COALITION/MH I-95a-c.

b) The question is attempting to use the term "primary role", intended by Manitoba Hydro to refer to the functionalization and classification stages of cost of service by applying it to the separate stage of assignment or allocation to different classes of customer. This latter interpretation was not intended by Manitoba Hydro's statement in its Submission. From a functionalization perspective, the primary purpose of the assets listed in the question above is to provide power supply, i.e. Generation. These assets have been functionalized on this basis. Within that meaning, these generation functions provide capacity and energy, and they are classified as such also. Hence, there is no inconsistency.

From a customer class perspective, the primary purpose of all the assets listed is to reliably serve Manitoba Hydro domestic load at lowest long term cost. However, on the basis that these assets are also available to serve export loads when not required by domestic customers, within cost of service, Manitoba Hydro assigns or allocates an appropriate share of the costs to Dependable and Opportunity Export sales.

c) As noted in the response to part b) of above, the "primary purpose of investment" was not intended to apply to the allocation stage of cost of service. From a functionalization and classification perspective, the primary purpose of each of the assets listed in the question is to provide power supply, both capacity and energy, and are functionalized and classified on this basis in the Study.

Section:	Appendix 3 Appendix 3.1	**Page No.:**	Page 4 Schedule B2-Amended Schedule C14
Topic:	Cost of Service Study		
Subtopic:	Use of Results		
Issue:	Comparison of Unit Costs and Rates		

PREAMBLE TO IR (IF ANY):

Appendix 3 states "The information in Schedule B2 is intended to provide a comparison of allocated unit costs with the corresponding price in the appropriate rate schedule".

QUESTION:

a) With respect to the results from PCOSS14-Amended, what is the appropriate Board approved rate schedule that should be used for comparative purposes?

b) Given that the revenue used in PCOSS14-Amended was adjusted to remove the 1.5% accruing to the deferral account (per Order 43/13), do the Board approved rates used for comparison purposes need to be adjusted? If yes, how? If no, why not?

RATIONALE FOR QUESTION:

To clarify the rates that should be used in for comparison purposes with the results of PCOSS14-Amended.

RESPONSE:

a) Please see Manitoba Hydro's response to COALITION/MH I-1a-d.

b) Theoretically, if one wanted to make such a comparison, the unit costs shown in Schedule B2 of PCOSS14-Amended would need to be increased by 1.5%.

Section:	Appendix 3 PCOSS14 Amended Model - Cost Details Transmission and Substations	**Page No.:**	Schedule C8-Amended Schedule C9-Amended Schedule C11-Amended
Topic:	Cost of Service Study		
Subtopic:	Transmission and Substations		
Issue:	Reconciliation of Data		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Schedule C8-Amended reports a total Rate Base Investment for Substations of $1,108,110,322. The data file provided on March 16th to support the PCOSS14-Amended model reports a total 2013-14 Rate Base Investment for Substations of $1,049,631,161. Please explain why the two values are different and reconcile.

b) Similarly the Capital Tax and Interest reported for Substations in Schedules C11-Amended and C9-Amended differ from those in the data file. Again, please explain why the values differ.

c) Schedule C8-Amended reports a total Rate Base Investment for HVDC Substations of $551,053,860. The data file provided on March 16th to support the PCOSS14-Amended model reports a total 2013-14 Rate Base Investment for HVDC Substations of $624,739,595 (sum of Rows 6 to 13). Please explain why the two values are different and reconcile.

d) Similarly the Capital Tax and Interest reported for HVDC Substations in Schedules C11-Amended and C9-Amended differ from those in the data file. Again, please explain why the values differ.

e) Schedule C8-Amended reports a total Rate Base Investment for Transmission of $534,921,489. The data file provided on March 16th to support the PCOSS14- Amended model reports a total 2013-14 Rate Base Investment for Transmission of $591,964,422. Please explain why the two values are different and reconcile.

f) Similarly the Capital Tax and Interest reported for Transmission in Schedules C11-Amended and C9-Amended differ from those in the data file. Again, please explain why the values differ.

g) Schedule C8-Amended reports a total Rate Base Investment for HVDC Transmission of $111,471,563. The data file provided on March 16th to support the PCOSS14-Amended model reports a total 2013-14 Rate Base Investment for HVDC Transmission (i.e. Bipole I & II) of $102,351,409. Please explain why the two values are different and reconcile.

h) Similarly the Capital Tax and Interest reported for HVDC Transmission in Schedules C11-Amended and C9-Amended differ from those in the data file. Again, please explain why the values differ.

RATIONALE FOR QUESTION:

To reconcile the data provided with the PCOSS14-Amended model and that in Appendix 3.

RESPONSE:

a) As per the note included in the Excel data file Cost Details Transmission and Substations provided on March 16, 2016, individual substation cost details do not include easements, land for future stations, and transformers in stock which are not tracked by station, nor forecast contributions and salvage which are not planned at station level of detail. Schedule C8 includes all of these additional items.

b) Capital Tax and Interest in Schedules C9 and C11 are based on the full Rate Base shown in Schedule C8, which includes additional assets as described in part a).

c) The Dorsey 230 and 500 kV Switchyards are not considered HVDC in the PCOSS, so the $532.556 million total (sum of Rows 6-10) would be the appropriate comparison. The Schedule C8-Amended rate base includes additional assets as described in part a).

d) Please see response to part b).

e) As per the note included in the Excel data file Cost Details Transmission and Substations provided on March 16, 2016, transmission rate base does not include easements, right of ways, or transmission development funds not tracked by line, nor forecast contributions and salvage which are not planned at transmission line level of detail.

f) Please see response to part b).

g) The two figures differ because the Northern Collector A/C transmission lines are included in the Transmission - HVDC row in Schedules C1-C12.

h) Please see response to part b).