Manitoba Industrial Power Users Group Book of Documents – Volume III
Manitoba Hydro 2017/18 and 2018/19 GRA
Exhibit MIPUG-23-3

Tab #	Description	Reference
1	Rate Increase Impacts	1. Calculated Table of Industrial Rate Increase 2. PUB-MFR-72, page 210 of 615
2	C10 'Customer Service General' (with highlighting added)	1. Tab 8 – page 13 2. Appendix 8.1 –pages 3, 17-19 (Note: added percentage weightings for number of customers) 3. PUB Order 164/16 –pages 79-81 4. 2015 Cost of Service Methodology Review - PUB/MH-I-57a-b 5. 2015 Cost of Service Methodology Review - MIPUG/MH-I-4a-c 6. MIPUG/MH II-8a-c 7. MIPUG/MH I-11a-f 8. Transcript from the current proceeding, December 19, 2017 (cross-exam between Ms. Dayna Steinfeld and Mr. Greg Barnlund), pages: 2555-2557
3	Revenue to Cost Comparison (RCC) ratios	1. Tab 8, Cost of Service and Load Research, page 2
4	Extracts from: Look North Report and Action Plan for Manitoba's Northern Economy (with highlighting added)	1. Pages 17-18, 23-24. Available online: https://www.gov.mb.ca/asset_library/en/looknorth/look-north-report.pdf
5	DSM	1. Appendix 7.2: 201617 Power Smart Plan, pages 2, Appendix A.1 – A.5 2. PUB Report on Needs For and Alternatives To (NFAT) Review, June 20, 2014 Pages 81, 92 & 251 3. MH Exhibit 45 in 2015/16 GRA – Letter from Minister re: PUB NFAT Report 4. Transcript from current proceeding, December 12, 2017 (cross-exam between Mr. Antoine Hacault and Mr. Terry Miles), page 1631.
6	Previous Board Order Extracts (with highlighting added)	1. Order 7/03 page 102 – 104, 110 2. Order 101/04 page 32 3. Order 116/08 page 315-316 4. Order 5/12 page 213 & 217 5. Order 116/12, page 23-24 6. Order 73/15, page 3-5 7. Order 59/16, page 3-5 8. Order 164/16 pages 23-24
7	Rate Schedule	1. Appendix 9.4 Updated, page 11 2. Appendix 9.4, page 11 (Original)

TAB 1

$ Billions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Yr. Total
MH16 Update with Interim - Appendix 3.8	1,744	1,866	1,995	2,163	2,331	2,515	2,647	2,725	2,807	2,893	23,686
MH16 Update with Interim (MH15 rates) - PUB/MH I-34 Attch 2	1,681	1,732	1,784	1,863	1,934	2,011	2,105	2,208	2,318	2,434	20,070
Difference	**63**	**134**	**211**	**300**	**397**	**504**	**542**	**517**	**489**	**459**	**3,616**

Hydro's 9 Largest Customers
PUB-MFR-72 pg. 210

12% of Revenue = **$434 million**

10 Yr Total Additional Revenue: $48 million Average per Largest Customer

4 Domestic rev.

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Manitoba Hydro's 9 largest customers comprise 12% of revenue and are concentrated in mining and energy sectors

1b

Large industrial

[redacted]

Source: Manitoba Hydro, BCG Analysis

TAB 2

- Inspections
- Meter Reading

Schedules 4.3 to 4.7 provide the detail of the cost makeup for each sub-function, which has in some cases been further categorized, the allocator, as well as the results.

Customer Service and Industrial & Commercial Solutions

General Customer Service activities previously aggregated and allocated through what has been referred to as the "C10" allocator have been disaggregated. The activities now reflected in this General category are those activities that Manitoba Hydro views as public safety-related, the costs of which are allocable to all customers. This includes the costs associated with outage calls, line locates, marketing research and development, safety watches, building moves, and rates and regulatory. These general customer service activities have been allocated to all customer classes proportionately by revenue by class.

A number of other general customer service activities aimed at smaller customers including disconnects/reconnects associated with customer maintenance, general inquiries, power quality issues, as well as service extension activities have been pooled and allocated to classes excluding GSL.

The costs of the Industrial and Commercial Solutions departments have been allocated only to GSL classes on the basis of each GSL class's revenue, as the activities and services of these departments are dedicated to these classes.

Manitoba Hydro is generally unsupportive of a straight un-weighted customer count allocation and has limited its use. The overwhelming dominance of the number of residential customers would result in no cost distinction between customer classes. A revenue allocator, specifically applied as discussed above, recognizes intuitively that the cost of providing these services increases as the size of the customer increases and results in the same allocated cost by class as a percentage of their total bill.

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2018
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
71.0171%	Residential	77,814	508,242	12.76	387,886	0%	n/a	n/a	183,304	7,586,096	7.53 **
	GS Small - Non Demand	13,971	42,707	27.26	67,584	0%	n/a	n/a	38,946	1,622,627	6.57 **
	GS Small - Demand	12,317	4,197	244.57	81,580	37%	2,623	11.45	51,203	2,146,454	4.79
	General Service - Medium	9,511	2,125	372.96	110,286	92%	7,722	13.14	76,197	3,204,436	2.65
.0449% -	General Service - Large <30kV	3,531	321	n/a	46,114	100%	4,302	11.54 *	41,147	1,745,362	2.36
.0056% -	General Service - Large 30-100kV	2,462	40	n/a	23,211	100%	3,358	7.65 *	36,248	1,578,519	2.30
.0022% -	General Service - Large >100kV	5,826	16	n/a	52,900	100%	7,815	7.51 *	101,920	4,504,939	2.26
	SEP	67	31	181.17	90	0%	n/a	n/a	580	25,500	2.63 **
	Area & Roadway Lighting	16,230	157,982	8.56	3,283	0%	n/a	n/a	1,991	82,415	6.40 **
	Total General Consumers	141,729	715,661		772,934		25,818		531,537	22,496,347	
	Diesel	396	785	42.06	-	0%	n/a	n/a	8,599	14,546	59.12 **
	Export	n/a	n/a	n/a	-	0%	n/a	n/a	38,159	8,557,000	0.45 ***
	Total System	142,125	716,446		772,934		25,818		578,296	31,067,893	

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

Section 4
Schedule 4.2
Allocation Tables

Table	Type	Costs Allocated	Method
E12	Unweighted Energy	Energy related costs within the Generation function.	Annual kWh sales as measured at generation. Distribution and transmission losses are assigned to each rate class based upon the voltage level in which they receive service.
E13	Unweighted Energy	Energy related costs within the Transmission function.	
D13	Winter Coincident Peak Demand	Demand related costs within the Transmission function.	Coincident peak demand of each class including losses during the top 50 winter coincident peak hours. Utilizes load research data for past eight years.
D14	Winter Coincident Peak Demand	Demand related costs within the Generation function	
D21	Winter Coincident Peak Demand	Costs within Subtransmission function.	Coincident peak demand of each class including losses during the top 50 winter coincident peak hours. Utilizes load research data for past eight years. Customers served at >100kV are excluded
D32	Class Non-Coincident Peak Demand	Cost of Distribution stations and station transformers within the Distribution Plant Function.	Non-Coincident peak demand of each class including losses. Utilizes load research data for past eight years. Customers served at >30kV are excluded.
D36	Class Non-Coincident Peak Demand	Cost of Distribution lines and infrastructure within the Distribution Plant Function.	Non-Coincident peak demand of each class including losses. Utilizes load research data for past eight years. The demand of GSL 0-30kV customers that do not use Secondary Distribution is reduced 30%. Customers served at >30kV are excluded.
D40	Class Non-Coincident Peak Demand	Cost of Distribution transformation within the Distribution Plant function.	Non-Coincident peak demand of each class including losses. Utilizes load research data for past eight years. GSL customers with customer owned transformation are excluded.
C27	Weighted Customer Count – Services	Cost of service drops within the Distribution Plant function	Customer count weighted by 5 for GSS:Three Phase, GSM and GSL classes. Customer count for Residential, GSS and GSM adjusted to recognize that there are multiple customers served by a single service. Classes served at > 30 kV, Flat Rate Water Heating, Area & Roadway Lighting excluded.
C40	Weighted Customer Count – Meters	Costs of meters and metering transformers within the Distribution Plant function	Customer count weighted by the relative cost of metering equipment as shown in Schedule 4.7 Flat Rate Water Heating, A&RL excluded

Section 4
Schedule 4.3
Customer Service Allocation Table

Table	Classes[1]	Customer Service Activity	Description	Operating ($ million)	Allocator	Rationale for Allocator
C10 General Customer Service	All	Education & Safety	Public Affairs, District office costs-public safety and education	1.2	Revenue	Line Locates/Moves/Safety Watches are for public safety and the protection of MH infrastructure Revenue allocator recognizes that costs could alternately be treated as A&G, which would result in a directionally similar allocation of costs to classes.
		Call Center Outage calls		1.2		
		Rates & Regulatory	Public Hearings, Cost of Service, Rate Design, and Load Research costs	3.0		
		Marketing R&D	Costs related to marketing plans, customer surveys, and enhancing business development in the province	1.3		
		Line Locates	Cost of locates for customers, MH work, public streets and roadways.	4.1		
		Building Moves & Safety Watches	Costs related to building and equipment moves, and oversight of work conducted near electric plant	3.1		
C10 Total				13.9		
C23 I&CS	GSL	Industrial & Commercial Solutions	Activities of departments focused on GSL incl. consultation, service extension, billing-related inquiries, power quality, general inquiries	4.3	Revenue	Service provided to GSL customers A revenue allocator recognizes that the cost to provide these services to customers generally increases as the size of the customer increases
C13 Customer Service – Smaller Customers	Excludes GSL	Customer & Community Service Work	Disconnects/reconnects for customer driven work, opening Customer Service Termination Enclosures, pulling meter, other work requested by the customer	4.3	Revenue	Services provided to smaller customers; GSL are provided similar services by I&CS and are excluded A revenue allocator recognizes that the cost to provide these services to customers generally increases as the size of the customer increases
		General Inquiries	District offices responding to general inquiries	2.0		
		Power Quality	District offices responding to power quality issues	1.0		
		Service Extensions	Pricing of service work, administration of customer service policy	13.9		
C13 Total ($ million)				21.2		

[1] Customer services costs are forecast separately for the Diesel class. Diesel is therefore excluded from all allocators.

Section 4
Schedule 4.3
Customer Service Allocation Table

C11 Billings		Adjustments & Complex Billing	Activities associated with billing large and/or complex customers, master bills, applicable taxes, any detailed analysis associated with billing	2.2	Weighted Customer Count	All--allocation based on estimate of time spent serving each class
		Customer Accounts	Administration of loans, customer moves, equal payment plan.	0.7		Allocation based on number of customer accounts excl. GSL (provided through I&CS), A&RL (provided in Complex Billing)
		Field Billing	District Office costs for payment receipt, cash balancing, moves, new customer accounts	7.2		Allocation based on number of customer accounts excluding GSL (billing inquiries handled by I&CS)
		CIS Admin	Support for staff using Banner, iNovah and MyBill.	1.2		All- allocation based on the number of customers (customer accounts for A&RL)
		Administrative	Postage, bill printing, Contact Centre billing related calls, and Banner maintenance	10.4		
C11 Total				21.7		
C12 Collections	Excl GSL, ARL	Collections	Cost of customer collection activities and bad debt expense	11.7	Weighted Customer Count	Historical data of collection activity and bad debt categorizes between res and commercial. Commercial portion prorated between classes on customer count A&RL excluded-- historically no collection issues. Infrequent GSL collection activities through I&CS.
C14 Inspections	Excludes A&RL	Inspections	Inspection of customer-owned plant	3.5	Weighted Customer Count	Historical data categorizes between residential and commercial. Costs then prorated based on customer count. A&RL facilities not customer-owned and thus excluded
C15 Meter Reading	Excludes A&RL	Meter Reading	Cost of meter reading activities	10.4	Weighted Customer Count	Weights reflect the relative frequency of meter reads. Excludes unmetered A&RL
Total Customer Service				86.7		

11.0 Customer Services Function

Manitoba Hydro's Customer Services function costs relate to serving and communicating with customers after delivery of energy. These costs include meter reading, billing, collections, information and customer assistance, advertising, sales, inspections, research and development, rates and cost of service, load research, as well as other departmental costs such as Power Smart Energy Services.

Customer Services Functionalization and Classification

Manitoba Hydro's Position

Based on Manitoba Hydro's functionalization, Customer Services account for 6% ($110 million) of the PCOSS14 Amended revenue requirement.

Manitoba Hydro proposes classifying Customer Services costs as Customer. These costs vary with the number of customers.

Intervener Positions

This issue was not contentious in this proceeding and the interveners did not put forward a position.

Board Findings

The Board finds that these services vary with the number of customers and should be classified as Customer Services.

Allocation of Customer Services General Costs

Manitoba Hydro's Position

Manitoba Hydro has several allocators for Customer Services costs. One of these allocators, which Manitoba Hydro calls C10, allocates costs related to customer service departments such as Consumer Consultation and Information, Municipal and

Community Relations, Service Extensions, Load Research, and other departments. Manitoba Hydro's C10 allocator is based on estimates of the time and efforts various departments devote to each customer class, which are then weighted by the budget for each area. The costs within Consumer Consultation and Information include costs related to Key Accounts and Major Accounts, which apply to larger customers such as GSL customers, as well as a generic Customer Service category.

Manitoba Hydro has agreed to review the C10 allocator but is of the view that GSL customers should not be excluded from the Customer Service costs category in advance of this review.

Intervener Positions

MIPUG's expert witness identifies $1.2 million of Customer Service costs in PCOSS14 that, in his view, are incorrectly attributed to the GSL 30-100kV and GSL >100kV classes. MIPUG does not agree that the costs within the generic Customer Service sub-category of Consumer Consultation and Information, such as line locates, safety watches, consumer consultations, building moves, and education and safety, apply to GSL customers. MIPUG argues that, since the $1.2 million in Customer Service costs do not apply to GSL customers, these costs should not be allocated to them.

Board Findings

The Board finds that costs in the Customer Service sub-category within the Customer Consultation and Information category should not be allocated to GSL 30-100kV or GSL>100kV customers unless and until Manitoba Hydro can provide a fulsome description of these costs. In this description, Manitoba Hydro shall:

- explain why these costs apply to the GSL classes,
- confirm that these costs are not already subsumed within the costs categorized as Key Accounts and Major Accounts, and

- justify why the customer weightings for the allocator, which provide greater weighting to GSL customers, are appropriate for these costs.

Allocation of Other Customer Services Costs

Manitoba Hydro's Position

Manitoba Hydro has agreed to update the customer weighting factors within its Customer Service allocators as time and resources allow.

Intervener Positions

The Coalition, GAC, and MIPUG each recommend that Manitoba Hydro update or provide additional support for various customer weightings. The allocation approach for these costs was not contentious in this proceeding and no intervener proposed alternative allocation methodologies.

Board Findings

The Board finds that, with the exception of the costs in the Customer Service sub-category of Customer Consultation and Information allocated to GSL >30kV classes, Manitoba Hydro's Customer Services allocators are appropriate for the allocation of Customer Services costs. The weightings used to allocate the Customer Services costs, such as for meter reading, billing, and collections, shall be updated.

Section:	Appendix 3.1	Page No.:	Schedules E10-E12, E14, E18-E19
Topic:	Customer Allocators		
Subtopic:	Weighting Factors		
Issue:	Vintage of Analysis		

PREAMBLE TO IR (IF ANY):

Several customer allocators weight the number of customers in each class based on MH analyses.

QUESTION:

For each of the schedules referenced in the table above:

a) Please provide the time period the analysis used to estimate the weighting factors was performed.

b) Is there a need to update any of these analyses? If so, when will they be updated? If not, why not?

RATIONALE FOR QUESTION:

Wish to confirm whether the analysis used to estimate the customer weights is reasonable.

RESPONSE:

The weights for the C10 Customer Service General allocator were last updated for PCOSS11, and C14 Electrical Inspections allocators were updated for PCOSS14.

Weights used for C11 Billing, C12 Collections, C40 Meter Investment and C41 Meter Maintenance are based on analysis conducted in 1991. Manitoba Hydro does not expect revised weights will have a material impact on COSS results, but acknowledges that due to the age of the study it is appropriate to update weights and will do so as resources are available.

Section:	PCOSS – Amended Allocation Program	Page No.:	6
Topic:	Allocator C10 –Customer Service General		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the justification for the C10 weighted ratio allocator and the background data or studies used to calculate the allocator.

b) Please list all costs assigned to the Distribution Service, Customer Service – General Cost category (C10) totalling $46.561 million for the 2013/14 forecast year.

c) Please provide the rationale behind Hydro's assignment between Distribution Service cost categories C10 (Customer Service – General), C11 (Customer Account – Billings) and C12 (Customer Account – Collections).

RATIONALE FOR QUESTION:

Reviewing methodology for customer service charges.

RESPONSE:

a) The C10 weighted allocator was introduced in 2001 to recognize the different levels of customer service provided, and therefore cost distinction, to each customer class. Prior to that time Manitoba Hydro allocated customer service costs on an un-weighted customer count basis that did not account for the different cost levels related to customer service.

The allocation is based on an analysis undertaken to estimate the efforts various departments devote to each customer class, which is then weighted by the budget for each department. For example, the Key Accounts Department spends their time providing service to General Service Large customers and no time on Residential customer service and is weighted accordingly. The resulting estimates of effort at the class level are broken down to a sub-class level based on relative customer count within each class.

The calculation of the C10 allocation shares can be found below.

Estimate of Class Share of Individual SCC's

	Consumer Consultation & Information	Municipal & Community Relations	Public Accountability	Power Quality	Service Extensions	Customer Policy	Rates & Cost of Service	Load Research
Res	45.6%	80.0%	33.8%	40.8%	17.2%	29.8%	13.7%	12.9%
GSS	26.8%	5.0%	18.7%	12.3%	25.9%	22.9%	12.9%	13.9%
GSM	10.3%	10.0%	14.5%	11.8%	41.4%	22.9%	10.0%	18.6%
GSL 0 - 30 kV	7.0%	2.0%	5.3%	11.1%	10.5%	5.8%	8.5%	38.3%
GSL 30-100KV	4.1%	0.7%	3.5%	10.4%	3.4%	4.3%	9.5%	4.6%
GSL 30-100KV Curtailable	1.4%	0.3%	1.4%	3.5%	1.1%	1.5%	3.2%	1.6%
GSL >100KV	3.8%	1.0%	6.7%	6.6%	0.3%	5.8%	11.8%	4.0%
GSL >100KV Curtailable	0.9%	1.0%	5.0%	3.5%	0.2%	4.1%	8.2%	0.5%
SEP	0.0%	0.0%	5.0%	0.0%	0.0%	0.0%	12.9%	3.7%
Lighting	0.0%	0.0%	6.1%	0.0%	0.0%	2.8%	9.1%	1.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Planned Orders by SCC

	Consumer Consultation & Information	Municipal & Community Relations	Public Accountability	Power Quality	Service Extensions	Customer Policy	Rates & Cost of Service	Load Research	Total
Planned Orders	19,420,477	2,824,767	1,631,670	1,329,450	2,093,862	277,657	624,779	643,296	28,845,958
Percent of Total Planned	67.3%	9.8%	5.7%	4.6%	7.3%	1.0%	2.2%	2.2%	100.0%

Class Share Weighted by Planned Orders

	Consumer Consultation & Information	Municipal & Community Relations	Public Accountability	Power Quality	Service Extensions	Customer Policy	Rates & Cost of Service	Load Research	Total
Res	30.7%	7.8%	1.9%	1.9%	1.3%	0.3%	0.3%	0.3%	44.5%
GSS	18.0%	0.5%	1.1%	0.6%	1.9%	0.2%	0.3%	0.3%	22.8%
GSM	7.0%	1.0%	0.8%	0.5%	3.0%	0.2%	0.2%	0.4%	13.2%
GSL 0 - 30 kV	4.7%	0.2%	0.3%	0.5%	0.8%	0.1%	0.2%	0.9%	7.6%
GSL 30-100KV	2.8%	0.1%	0.2%	0.5%	0.2%	0.0%	0.2%	0.1%	4.1%
GSL 30-100KV Curtailable	0.9%	0.0%	0.1%	0.2%	0.1%	0.0%	0.1%	0.0%	1.4%
GSL >100KV	2.6%	0.1%	0.4%	0.3%	0.0%	0.1%	0.3%	0.1%	3.8%
GSL >100KV Curtailable	0.6%	0.1%	0.3%	0.2%	0.0%	0.0%	0.2%	0.0%	1.4%
SEP	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.3%	0.1%	0.6%
Lighting	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.2%	0.0%	0.6%
Total	60.4%	9.5%	4.1%	3.5%	6.9%	0.8%	2.2%	2.2%	100.0%

Allocation Table — Retail Prospective Cost Of Service Study
Number Of Customers - Adj. For Water Htg. excluding Street Lighting

		Curtailable Class	Class	Total
Residential	Standard & All Electric		462,217.0	462,217.0
	Seasonal		20,888.0	20,888.0
	Water Heating		388.2	388.2
Total Residential		-	483,493.2	483,493.2
General Service Small	Non-Demand		52,539.0	52,539.0
	Demand		12,492.0	12,492.0
	Seasonal		859.0	859.0
	Water Heating		38.0	38.0
Total General Service Small		-	65,928.0	65,928.0
SEP	GSM		24.0	24.0
	GSL		5.0	5.0
Total SEP		-	29.0	29.0
General Service Medium			1,974.0	1,974.0
General Service Large	0-30KV	-	288.0	288.0
	30-100KV	1.0	19.0	40.0
	>100KV	2.0	14.0	16.0
Total General Service Large		3.0	341.0	344.0
Area & Roadway Lighting			-	-
Total General Consumers		3.0	551,765.2	551,768.2
Diesel			-	-
Total System		3.0	551,765.2	551,768.2

Allocation Table — Retail Prospective Cost Of Service Study
C10 Weighted Ratio - Customer Service

		Curtailable Class	Class	Total
Residential	Standard & All Electric		42.51%	42.51%
	Seasonal		1.92%	1.92%
	Water Heating		0.04%	0.04%
Total Residential			44.47%	44.47%
General Service Small	Non-Demand		18.18%	18.18%
	Demand		4.32%	4.32%
	Seasonal		0.30%	0.30%
	Water Heating		0.01%	0.01%
Total General Service Small			22.82%	22.82%
SEP	GSM		0.54%	0.54%
	GSL		0.11%	0.11%
Total SEP			0.65%	0.65%
General Service Medium			13.16%	13.16%
General Service Large	0-30KV		7.59%	7.59%
	30-100KV	1.40%	4.12%	5.52%
	>100KV	1.41%	3.78%	5.19%
Total General Service Large		2.81%	15.49%	18.30%
Area & Roadway Lighting			0.61%	0.61%
Total General Consumers		2.81%	97.19%	100.00%
Diesel				0.00%
Total System		2.81%	97.19%	100.00%

Allocation Table — Retail Prospective Cost Of Service Study
C10 Weighted Ratio - Customer Service Total

		Curtailable Class	Class	Total
Residential	Standard & All Electric		234,550.8	234,550.8
	Seasonal		10,599.6	10,599.6
	Water Heating		197.0	197.0
Total Residential			245,347.3	245,347.3
General Service Small	Non-Demand		100,321.5	100,321.5
	Demand		23,853.1	23,853.1
	Seasonal		1,640.2	1,640.2
	Water Heating		72.6	72.6
Total General Service Small			125,887.3	125,887.3
SEP	GSM		2,962.1	2,962.1
	GSL		617.1	617.1
Total SEP			3,579.3	3,579.3
General Service Medium			72,602.7	72,602.7
General Service Large	0-30KV		41,874.1	41,874.1
	30-100KV	7,724.7	22,738.9	30,463.6
	>100KV	7,798.2	20,839.8	28,638.0
Total General Service Large		15,522.9	85,452.8	100,975.7
Area & Roadway Lighting			3,376.0	3,376.0
Total General Consumers		15,522.9	536,245.4	551,768.3
Diesel				-
Total System		15,522.9	536,245.4	551,768.3

b)

	Costs ($000)
R&D-Customer Service	317
Consumer Consultation & Information	28,747
Power Quality Invest.	1,944
Service Extensions	3,112
Customer Policy Admin.	413
Municipal & Community Relations	4,105
Public Accountability	3,761
Rates & Cost of Service	928
Load Research	903
Total Operating & Depreciation	44,231
Interest on Buildings	768
Interest on General Equipment	1,562
Total C10 Costs	**$ 46,561**

c) The cost of these activities relate to distinct departments at Manitoba Hydro and as a result can be tracked and allocated separately from Customer Service General costs.

REFERENCE:

PUB/MH I-145

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a breakdown of the allocation (including directly matched revenues) of non-energy revenue ($30,183,945) to each Cost of Service function cost category.

b) Please provide a breakdown by customer class share for each non-energy revenue 'item' listed in the table provided in Hydro's response to PUB/MH I-145.

c) The response to MIPUG/MH I-11d indicates that "Building Moves" are mostly fully recovered from the party requesting the service, and that these collections are tracked as "other revenue" functionalized using the SAP Labour Allocator. Please provide a table showing the allocation of the building moves expenses to each class, and the corresponding revenue to each class associated with this cost recovery (i.e., does the COS match the revenue with the expense it is intended to cover).

RATIONALE FOR QUESTION:

RESPONSE:

a) The table below provides the breakdown of PCOSS18 Non-Energy Revenue into the cost categories used in the COS.

	Cost Category ($ million)
Offset to Operating Expense	19.5
Offset to Depreciation Expense	10.7
Total	30.2

b) The table below provides the breakdown of PCOSS18 Non-Energy Revenue by revenue source and the allocation of the revenue to customer classes in the COS.

	Amortization of Customer Contributions ($ 000)	Joint Use ($000)	Permit Inspection Fees ($000)	Operating Expense Recoveries ($000)	Goods & Services Sold to Outside Parties ($000)	Other ($000)
Residential	4,071	2,727	748	2,795	1,304	1,863
GSS Non Demand	712	478	976	530	247	353
GSS Demand	830	560	230	570	266	380
GSM	1,127	753	38	768	358	512
GSL 0-30 kV	448	256	6	350	164	234
GSL 30-100 kV	110	0	1	238	111	159
GSL >100 kV	234	0	0	620	289	413
SEP	0	0	1	0	0	0
A&RL	1,835	27	0	99	46	66
Diesel	1,333	0	0	30	14	20
Total	10,700	4,800	2,000	6,000	2,800	4,000

c) The table below provides the breakdown of the allocation of Building Move related expenses and revenues in PCOSS18, as well as the percentages allocated to each class.

	Building Moves Expense ($ 000)	Building Moves Expense (%)	Building Moves Revenue ($ 000)	Building Moves Revenue (%)
Residential	769	42	140	47
GSS Non Demand	177	10	26	9
GSS Demand	186	10	29	10
GSM	243	13	38	13
GSL 0-30 kV	114	6	18	6
GSL 30-100 kV	89	5	12	4
GSL >100 kV	229	12	31	10
SEP	0	0	0	0
Area & Roadway Lighting	27	1	5	2
Diesel	0	0	1	0
Total	1,834	100	300	100

REFERENCE:

Tab 8, Pages 13 and 18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With reference to PCOSS18, pages 18-19, for each row on the 2 pages please provide a break down by class of the noted costs.

b) With respect to the C10 Customer Service table at page 18 of PCOSS18, please provide a discussion on each row (totalling $13.9 million) as to why the costs are not predominately if not entirely related to distribution service.

c) Does Manitoba Hydro "Line Locates" service play a role in locating transmission lines, or primarily distribution lines? Please provide a breakdown of locates by transmission versus distribution.

d) Please provide a breakdown of the $3.1 million in costs that Hydro incurs for building moves and overseeing work near electric plant (PCOSS18, page 18). What costs does this represent? Are these activities performed on a cost-recovery basis?

e) Does Manitoba Hydro incur costs for "building moves and oversight of work conducted near electric plan" related to transmission plant, or does this only (or at least predominately) apply to activities that are in the vicinity of distribution lines?

f) Please provide a description of the $1.2 million in "Call Center Outage Calls" (PCOSS18, page 18) indicating the type of costs and what activities are performed by the call center. Is the call center not primarily oriented to serving distribution level customers, with transmission connected customers receiving their customer service contacts through the Industrial and Commercial Solutions group?

RATIONALE FOR QUESTION:

RESPONSE:

a) The following table provides details on the allocation of Customer Service costs broken down by class.

Customer Service Activity		Class Share of Operating ($ million)								
		Res	GSS ND	GSS D	GSM	GSL 0-30kV	GSL 30-100 kV	GSL >100kV	A&RL	Total
C10	Education & Safety	0.52	0.12	0.13	0.16	0.08	0.06	0.15	0.02	1.2
C10	Contact Center - Outages	0.51	0.12	0.12	0.16	0.08	0.06	0.15	0.02	1.2
C10	Rates & Regulatory	1.25	0.29	0.30	0.40	0.19	0.14	0.37	0.04	3.0
C10	Marketing R&D	0.56	0.13	0.13	0.18	0.08	0.06	0.17	0.02	1.3
C10	Line Locates	1.70	0.39	0.41	0.54	0.25	0.20	0.51	0.06	4.1
C10	Building Moves & Safety Watches	1.28	0.29	0.31	0.41	0.19	0.15	0.38	0.05	3.1
C23	Industrial & Commercial Solutions	-	-	-	-	1.14	0.89	2.29	-	4.3
C13	Customer & Community Service Work	2.33	0.54	0.57	0.74	-	-	-	0.08	4.3
C13	General Inquiries	1.11	0.25	0.27	0.35	-	-	-	0.04	2.0
C13	Power Quality	0.57	0.13	0.14	0.18	-	-	-	0.02	1.0
C13	Service Extensions	7.62	1.75	1.84	2.41	-	-	-	0.27	13.9
C11	Adjustments & Complex Billing	1.91	0.21	0.05	0.04	0.01	0.00	0.00	0.01	2.2
C11	Customer Accounts	0.59	0.06	0.01	0.01	0.00	0.00	0.00	0.00	0.7
C11	Field Billing	6.21	0.67	0.16	0.14	0.03	0.00	0.00	0.02	7.2
C11	CIS Admin	0.99	0.11	0.03	0.02	0.00	0.00	0.00	0.00	1.2
C11	Administrative	8.94	0.97	0.23	0.21	0.04	0.01	0.00	0.03	10.4
C12	Collections	10.68	0.83	0.19	0.03	-	-	-	-	11.7
C14	Inspections	1.29	1.69	0.40	0.07	0.01	0.00	0.00	-	3.5
C15	Meter Reading	8.62	1.12	0.54	0.09	0.01	0.00	0.00	-	10.4
Total		56.7	9.7	5.8	6.1	2.1	1.6	4.0	0.7	86.7

b) The activities listed on page 18 as C10 Customer Service General costs continue to be functionalized as Distribution Service in PCOSS18. Manitoba Hydro assumes the question was intended to seek clarification why the costs are not predominately if not entirely related to customers served at the distribution level.

The services included in this subfunction are not provided for the specific benefit of individual customers or class of customers, rather they are for the public good and applicable to all customer classes.

C10 Customer Service Activity	Rationale
Education & Safety	Programs include safety around dams, waterways, substations, and overhead powerlines. The programs are not specifically related to distribution plant, or customers served at the distribution level.
Contact Center - Outages	The contact center is the initial point of contact for all customers, and not specifically for customers served at the distribution level.
Rates & Regulatory	All customer classes participate in and benefit from the regulatory process.
Marketing R&D	Activities include creating marketing plans, customer surveys, maintaining customer coding databases, and enhancing business development in the province. These activities are not specifically related to customers served at the distribution level.
Line Locates	Service primarily relates to distribution facilities, but would also include transmission and subtransmission voltage facilities.
Building Moves & Safety Watches	Service primarily relates to distribution facilities, but would also include transmission and subtransmission voltage facilities.

c) Manitoba Hydro does not track the service by type of electric plant and is therefore unable to provide a breakdown of how much time or cost is specifically related to locating transmission versus distribution lines. Based on the installed length of underground transmission lines compared to underground distribution, it is reasonable to assume the service is primarily related to distribution facilities. However, Manitoba Hydro can confirm that the Line Locates category would include some activities related to locating transmission lines.

d) In PCOSS18 approximately 60% of the $3.1 million cost is related to building moves, and the remaining 40% is related to safety watch activities. Manitoba Hydro's cost recovery policies for the activities are summarized below. The cost recovery revenues are included as part of Other Revenue, and are functionalized broadly using the SAP Labour Allocator in the PCOSS.

Building moves - For building or structure moves originating in the province, Manitoba Hydro incurs costs for work provided during normal working hours to inspect the route, as specified by the mover prior to the move. During normal work hours, Manitoba Hydro cost shares on a 50/50 shared basis, one qualified Corporation representative who will accompany the movers and perform switching required due to the building or structure move. Manitoba Hydro recovers costs for work performed such as raising and lowering lines, rerouting lines, etc, and any time outside of normal working hours at the appropriate overtime rate. For buildings or structures originating outside of the province and being moved into or through the province Manitoba Hydro recovers full cost.

Overseeing Work Near Electric Plant - To ensure the safety of customers and their contractors when working in close proximity to facilities, Manitoba Hydro incurs a cost to provide residential homeowners and their contractor's safety watching services during normal working hours. For contractors, Manitoba Hydro incurs a cost to provide one (1) man hour at no cost, for switching or on-site safety watching per project, each day. The remainder of safety watching time is on a 50/50 shared basis with the contractor during normal work hours. All time associated with safety watching outside of regular business hours is charged to the contractor at the appropriate overtime rate.

e) Manitoba Hydro does not track these services by type of electric plant and is therefore unable to provide a breakdown of how much time or cost is specifically related to transmission versus distribution lines. Given the nature of the work, it is reasonable to assume the service is primarily related to distribution facilities. However, Manitoba Hydro can confirm that the Building Moves & Safety Watch category would include some costs related to work in the vicinity of transmission lines.

f) The customer contact centre activities are tracked by line of business (gas vs electric) as well as nature of the call (billings, collections, outages, call before you dig). The $1.2 million represents the costs for call center staff fielding outage related calls. The contact center provides the initial point of contact for customers in all customer classes, which in the case of General Service Large customers the process will include notifying the client representatives from the Industrial and Commercial Solutions Division of the outage.

embedded cost of service study because it's based on forecast financial costs for a single test year period in the integrated financial forecast?

MR. GREG BARNLUND: That's correct.

MS. DAYNA STEINFELD: And, Mr. Barnlund, I think I referenced this earlier that I understand that Ms. Doerksen testified before the Board in the cost of service study review but it is appropriate to put these questions to you on cost of service study matters?

MR. GREG BARNLUND: Yes, it is.

MS. DAYNA STEINFELD: I will do so then. I'd to spend some time talking about the customer services function. And perhaps you can confirm for me that the -- the costs in this function relate to serving and communicating with customers after the delivery of energy. So, so it would include things like metre reading or billings or collections; is that right?

MR. GREG BARNLUND: Yes, there's -- there's a number of different activities that would be captured in that category, yes.

MS. DAYNA STEINFELD: And in Order 164 of '16 the Board agreed with Manitoba Hydro that services costs should be classified in the customer classification as the costs vary with the number of customers; is that right?

MR. GREG BARNLUND: That's correct.

MS. DAYNA STEINFELD: And at the time of that review Manitoba Hydro allocated costs related to customer service departments; is that right?

MR. GREG BARNLUND: Yes.

MS. DAYNA STEINFELD: And -- and one (1) of those departments was a consumer consultation and information department?

MR. GREG BARNLUND: That would be an activity, but yes, that -- they were on a department base so we've now -- we've now disaggregated those into -- into activities themselves.

MS. DAYNA STEINFELD: And we'll -- we'll go there and look at the disaggregation in a moment but the -- the allocator used was called the C-10 (phonetic) allocator?

MR. GREG BARNLUND: That's correct.

MS. DAYNA STEINFELD: Is there a brief explanation that you can provide for what the C-10 allocator is?

(BRIEF PAUSE)

MR. GREG BARNLUND: So C-10 is basically the collection of -- of general customer service costs. So it's not meter reading, it's not billing, it's not collections. There's a number of other activities that are involved and that's captured in the C-10 category.

MS. DAYNA STEINFELD: And previously, there was an allocation that was weighted by the budget for each of the areas, is that right?

MR. GREG BARNLUND: Yes, that's correct.

MS. DAYNA STEINFELD: And now Manitoba Hydro is allocating to the customer classes proportionately by revenue for the class?

MR. GREG BARNLUND: That's correct.

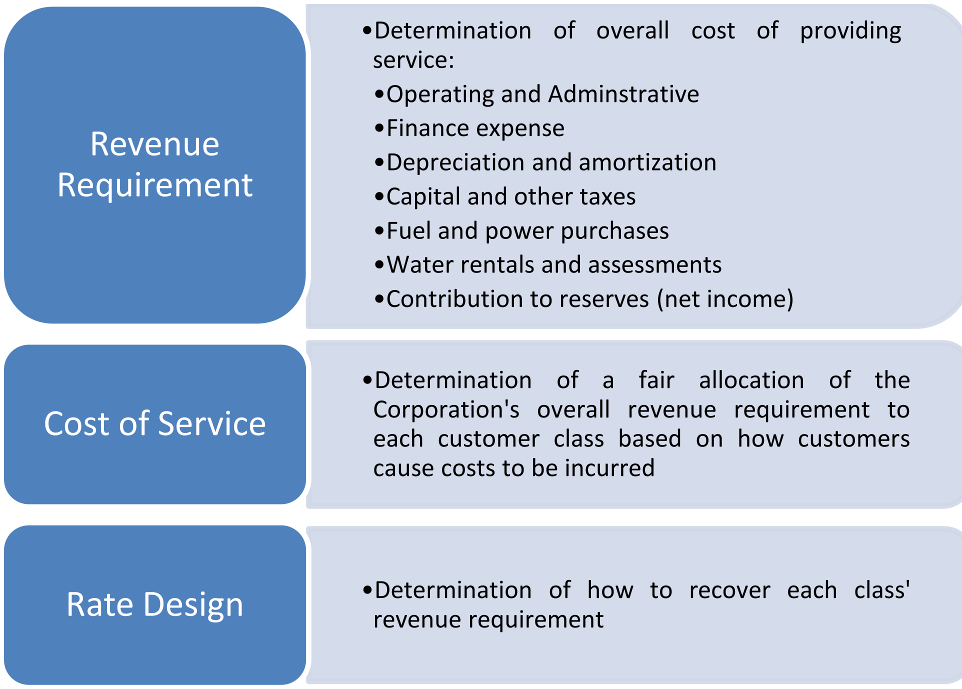
MS. DAYNA STEINFELD: So let's turn to what you were just referencing, Mr. Burnlund, which I believe is at book of documents, volume 5, tab 106, page 8.

And so this is where we see what -- what you just mentioned, this segregation of the customer service activity in -- in -- into different activities?

MR. GREG BARNLUND: Yes, that's correct.

TAB 3

Figure 8.1 Sequential Steps for the Development of Utility Rates



Manitoba Hydro's COS Study is an embedded cost study in that it is based on forecast financial costs for a single test year period from the Integrated Financial Forecast ("IFF"). Manitoba Hydro utilizes net plant investment for the purpose of allocating revenue requirement items such as finance expense, capital taxes, and the required contributions to financial reserves. O&A and depreciation is forecast by facility or service so it can then be allocated amongst the customer classes.

The results of the study indicate the degree to which each rate class's allocated costs are being recovered through revenues collected from the class. The ratio of class revenues and costs is referred to as Revenue Cost Coverage ("RCC"). Although the study has the appearance of exactness, it provides a reasonable estimate of the costs to serve each class. To recognize this Manitoba Hydro, similar to other utilities in Canada, uses a Zone of Reasonableness in rate setting. In Manitoba, to the extent that a customer class's RCC falls in a range of 95% to 105%, it is accepted that its revenues are recovering the allocated cost. The matter of appropriate reliance on Cost of Service, including the target Zone of Reasonableness range is discussed further in this Tab, Section 8.5.

TAB 4

LOOK NORTH | Report and Action Plan

For Manitoba's Northern Economy

Things That Matter Most

This document presents a distilled and synthesized version of findings from hundreds of inputs across communities, industries and individuals.

However, there are some things that rise above the rest, things that are front of mind for many and talked about a lot, things warranting focus and concerted effort, things that have the potential to create the biggest quantum shifts, or act as catalysts for wider change.

These are the things we heard often, that matter most to many.

ITEM 1

NORTHERN MINERAL AND OTHER RESOURCE POTENTIAL

Despite current industry decline and massive job loss in the northern mining industry, the latent mineral potential of the north is perhaps still the single most likely source of long-term northern prosperity.

It has sustained the north for close to 80 years, and with the right support and investment could sustain the north for another 80 years. The problems are known and visible, as are many of the solutions. The greatest barriers to growth are regulatory, procedural and relational.

Other important resource sectors such as forestry, fishing, hydro, agriculture, energy and tourism also provide opportunities for new partnerships and growth.

There needs to be a strong and unified partnership between public and private sectors to knuckle down and get on with the jobs to be done.

ITEM 2

INDIGENOUS ENGAGEMENT AND PARTNERSHIPS

Indigenous peoples and communities are ready for models, protocols and supports to enable the development of partnerships. This warrants a joint effort between Indigenous communities and industry, and supported by government, to identify partnership opportunities for increased economic development that will contribute to local economies and the broader Manitoba economy.

ITEM 3

STRATEGIC INFRASTRUCTURE INVESTMENT

'All weather roads', 'rail', 'air' and 'broadband' were among the most common topics to arise in conversation in the north, however, they are topics that still give rise to more questions than answers. It is time for answers and they will only come from continued engagement plus a concerted effort to conduct sufficient analysis to mount any case for investment.

The current suspension of the Gillam to Churchill rail service highlights the importance of infrastructure to northern prosperity.

ITEM 4

HOUSING CHALLENGES AND OPPORTUNITIES

The poor state of housing, over-crowding and low levels of home ownership in northern Manitoba, has significant impacts on the economy. These challenges will require all parties to bring together the skills and knowledge that exists in northern communities to identify new models that better meet the needs in northern Manitoba.

However, many of the proposed solutions would require policy changes to support local solutions and new models.

ITEM 5

ENTERPRISE ECO-SYSTEM OF SUPPORT

An enterprise eco-system needs to be built, providing a clear pathway for enterprise growth and connection to the right support at the right time. This will require a lead entity to coordinate.

It starts with developing enterprise culture in schools, and then needs to inspire and stimulate enterprise from start-up all the way through to growth and expansion.

ITEM 6

EDUCATION, TRAINING AND WORKFORCE DEVELOPMENT

Improved alignment between identified local industry and community needs with education and training opportunities is necessary to build new 'industry-fit' education pathways.

General Observations

A GAP BETWEEN RESOURCE POTENTIAL AND REALITY

There are evident gaps between natural resource potential and current reality. For example, in 2015 the Manitoba mining industry was worth $1.3B (below $1B today), compared to Saskatchewan and Ontario that were worth $8.5B and $10.7B respectively. Similarly, current annual cut allowances in timber are not being fully optimized.

Both of these scenarios paint a picture of industries that actually have significant head-room for growth – if the barriers to growth can be addressed and timely support provided.

LONG-TERM RELIANCE ON KEY COMPANIES HAS LIMITED INNOVATION AND ENTREPRENEURSHIP

Long-term stability and reliance on key companies has not prepared people for innovation and enterprise. There is a general absence of an enterprise mindset in the region.

LONG-TERM GOVERNMENT DEPENDENCE

In many communities there has been long-term dependence on government funding which generates a default expectation that government will always provide.

DISCONNECTS

There are disconnects across and within the region between:

- Support provided and support needed.
- Education provided, and local industry and community needs.
- Communities and leadership.
- Winnipeg and the south, and the north.
- Sectors, and within sectors.
- Indigenous communities and their adjacent communities.
- Municipal, provincial and federal government.

In many cases it is simply the absence of a relationship that is hindering progress and limiting the identification of opportunity.

NEED FOR YOUTH ENGAGEMENT AND FOCUS

Everywhere we went, and nearly every meeting and workshop held, the need to invest in youth engagement and development was identified. While youth are the fastest growing portion of the population and future of the economy, in many cases, youth cannot see opportunity or future in the north and question the relevance of their education.

NEED FOR STRONG LEADERSHIP AND ADVOCACY

There are many leaders **in** the north, but a general lack of coordinated leadership **for** the north.

Industry Needs and Opportunities

MINING

Despite the evident current trend of industry decline, mining has been, and still shows potential to be, the greatest source of economic growth in the north.

If you are looking for a 'magic bullet', then mining could still very well be it, albeit one that is slow to deliver. When you get it right the benefit and value endures for decades, just as the mines opened up in the 1950s and 1960s continue to deliver benefit today.

The evident geological potential is well beyond current value, and despite decline, adjacent provinces have shown growth and were cited by many as having more advanced regulatory support, better investment attraction policies, better First Nations partnerships and stronger investment.

What we are experiencing now is the downstream effect of under-investment in grass-roots exploration and survey, coupled with downturn in global commodity prices, increased environmental pressure, more complicated consultation processes, some long-serving mines reaching the end of their life-cycle, while others sit inactive and 'locked up' by permits.

Investment in growing the 'grass-roots' of the industry in survey, exploration, prospecting and First Nations engagement, is needed to expand the base and future potential of the Industry. This justifies a long-term plan and investment, to deliver long-term benefit.

It will take government and industry partnership and targeted investment to turn a trend of decline into a trend of growth, if the regions mineral potential is to be realized.

The upside of this long-term investment could then be measured in billions in terms of value and decades in terms of enduring impact and legacy, just as the 'roads to resources' program and policies of 1957-63 opened up access to develop the industries we have reaped the benefit of to this very day.

Companies like Vale and Hudbay have arguably done more for the north recently than other private or public organizations, despite their trend of decline.

Their investment in workforce and community development, and initiatives like TEDWG (Thompson Economic Development Working Group) and partnership with education providers like UCN, is significant. They have been more proactive in their relationships with First Nations than is evident in most other sectors.

The mining industry continues to suffer from a prevailing public perception that it is a 'dirty' industry, despite raised environmental standards and increased effort in minimizing impact and investment in environmental restoration. It is a bit like the person who has given up smoking still being labelled as a smoker.

This strategy does not go into deep detail as to what has to be done, as what is also evident is that the industry and industry bodies are very clear on the issues and barriers they face, and in their identification of solutions. What we have discovered through Look North simply aligns with, and serves to reinforce, their point of view.

The Mining Association of Manitoba and the Manitoba Prospectors and Developers Association have both engaged with Look North proactively and are very supportive of the agenda.

What really needs to happen is a closer and more direct partnership between government, industry, First Nations and other stakeholders to address barriers to growth and redirect the industry from its current path of decline to one of long-term growth. This needs to be viewed in terms of inter-generational return on investment, rather than cost, as the short term costs to turn the industry around have the potential to deliver inter-generational outcomes for the future of the north.

The Task Force proposes establishment of a Joint Action Group for this purpose.

Industry Needs and Opportunities

INDUSTRY NEEDS AND OPPORTUNITIES

TOURISM

A 'Northern Manitoba Tourism Strategy: 2017-2022' has been drafted through a partnership between Tourism North and Travel Manitoba and will be a companion strategy to this.

The Tourism sector in Manitoba represents close to 3% of GDP.

It is relatively immature as a sector when viewed from a global perspective, particularly in terms of international tourism.

The majority of tourism revenue is domestic at 87% with 9% from other provinces, 3% from USA (which could be considered semi-domestic given proximity to market), and 1% from overseas.

Overseas visitors are by far the biggest spenders in the north spending an average $2,229.00 per person compared to $184.00 per person per visit from Manitobans.

While there are many businesses working with Travel Manitoba to promote the region, the prevailing strategy is a push, not pull, one i.e. based on product development and marketing what the region has to offer, rather than responding to deep market insights.

There are obvious key barriers to international visitor attraction in terms of distance and cost, when a flight from Winnipeg to Churchill for instance can cost more than the flight from country of origin.

The tourism sector is the second largest employer in the region behind health services, but given the largely domestic market of the cluster, this is not a significant contributor to attracting export revenue.

Tourism does however provide opportunity for small local operators to gain a livelihood so the economic value of the domestic market is not to be under-estimated and provides scope for local growth.

Areas of strength and potential growth are identified in the report down to individual community level.

FORESTRY

The forestry industry still has room for growth, both in terms of optimizing sustainable annual cut allowances, but also in industry innovation, diversification and value add.

While there are significant barriers and complexity to optimizing annual cut allowances, including the necessary capital required, there is evident opportunity to explore the wider forest and timber eco-system to identify new opportunities.

FISHERIES

Regulatory liberation of the fishing industry from a single channel operation, to an open market one, opens up new opportunities for collaboration and a more targeted higher value market approach.

The industry then is in its infancy in terms of an open market model and will need to go through some maturing to reach its potential.

The open market model will create opportunities for value growth in quota species, and will likely lead to more open competition. This may see operators quick to collaborate and thrive, while others may struggle to adjust.

Non-quota species could also provide new and less limited market opportunities for those who seek to commercialize them, and this will need to be closely monitored to assure sustainability.

The commercial value of one fish sold is still less than the economic value of one fish caught, if the angler has invested in lodging, food, travel and gear, within the local economy.

TAB 5

The following table outlines the forecasted achievements over the next 15 years:

Programs	Capacity Savings (MW)	Energy Savings (GW.h)	Natural Gas Savings (million m^3)	Utility Investment (millions $)
New Homes Program	8.3	18.3	7.8	$3.2
Home Insulation Program	14.6	29.3	6.4	$27.1
Water and Energy Saver Program	2.4	13.2	1.6	$5.8
Affordable Energy Program	9.7	25.2	6.9	$93.7
Refrigerator Retirement Program	0.9	8.7	-	$8.4
Drain Water Heat Recovery Initiative	0.0	0.2	-	$0.1
Residential LED Lighting Program	4.9	15.4	-	$7.4
Community Geothermal Program	25.0	50.0	-	$22.5
Appliances	0.1	0.4	0.0	$0.4
HRV Controls	1.8	4.5	0.7	$2.8
Power Bars	0.0	0.0	-	$0.0
Smart Thermostats	0.1	0.2	0.1	$0.3
Plug-in Timers	0.0	0.1	-	$0.0
Community Energy Plan	-	-	-	$1.7
Power Smart Residential Loan	2.7	5.3	5.7	$0.0
Power Smart PAYS Financing	1.7	3.4		$0.0
Residential Earth Power Loan	6.6	20.1	0.3	$0.0
Residential Programs	**78.9**	**194.5**	**29.3**	**$173.6**
Commercial Lighting Program	152.5	623.2	-	$123.3
LED Roadway Lighting Conversion Program	7.2	48.5	-	$44.4
Commercial Building Envelope - Windows Program	8.2	25.2	4.5	$23.7
Commercial Building Envelope - Insulation Program	14.9	33.8	12.6	$40.0
Commercial Geothermal Program	18.7	37.4	-	$16.7
Commercial HVAC Program - Boilers	-	-	3.1	$1.9
Commercial HVAC Program - Chillers (Water-Cooled)	-	0.9	-	$0.2
Commercial HVAC Program - CO2 Sensors	2.7	4.4	1.0	$4.0
Commercial HVAC Program - HRVs	19.7	40.3	6.4	$35.4
Commercial HVAC Program - Air Cooled Chillers	-	24.5	-	$11.9
Commercial HVAC Program - Water Heaters	-	-	2.1	$2.4
Commercial Custom Measures Program	8.0	35.1	2.2	$12.4
Commercial Building Optimization Program	3.2	15.8	3.7	$9.3
New Buildings Program	41.3	139.0	3.8	$13.2
Commercial Refrigeration Program	8.7	71.2	-	$13.5
Commercial Kitchen Appliance Program	0.2	1.3	0.3	$0.3
Network Energy Management Program	0.0	0.3	-	$0.1
Internal Retrofit Program	3.4	17.5	0.1	$10.6
Power Smart Energy Manager	3.5	15.5	1.3	$3.7
Power Smart Shops	3.8	12.5	0.1	$3.6
Race to Reduce	-	-	-	$0.8
Parking Lot Controller	-	2.6	-	$0.5
Power Smart for Business PAYS Financing	-	-	0.3	$0.0
Commercial Programs	**296.4**	**1,148.9**	**41.4**	**$371.8**
Performance Optimization Program	50.0	397.0	-	$122.2
Natural Gas Optimization Program	-	-	14.0	$7.8
Industrial Programs	**50.0**	**397.0**	**14.0**	**$130.0**
Energy Efficiency Subtotal	**425.2**	**1,740.3**	**84.7**	**$675.3**
Curtailable Rate Program	159.5	-	-	$106.6
Load Management	**159.5**	**-**	**-**	**$106.6**
Bioenergy Optimization Program	51.1	106.4	-	$37.5
Customer Sited Load Displacement	66.0	504.1	-	$81.8
Load Displacement & Alternative Energy	**117.1**	**610.6**	**-**	**$119.4**
Conservation Rates - Residential	19.6	163.5	-	$13.2
Conservation Rates - Commercial	30.9	257.1	-	$17.3
Conservation Rates	**50.6**	**420.6**	**-**	**$30.5**
Fuel Choice	145.6	291.3	-27.7	$53.8
Fuel Choice	**145.6**	**291.3**	**-27.7**	**$53.8**
Residential Air Source Heat Pumps Program	-	7.4	-	$2.5
Residential Future Opportunities	19.0	91.7	-	$50.6
Residential Solar Photovoltaics Program (PV)	3.2	35.3	-	$35.9
Residential Solar Thermal Program - Water Heating	0.0	0.2	-	$0.3
Residential Solar Thermal Program - Pool Heating	-	2.6	0.5	$1.3
Commercial Future Opportunities	19.0	91.7	-	$54.6
Commercial Solar Photovoltaics Program (PV)	14.7	138.7	-	$87.6
Commercial Variable Speed and Frequency Drives	0.1	4.7	-	$2.7
Industrial Future Opportunities	19.0	91.7	-	$59.9
Other Emerging Technologies	**75.2**	**464.1**	**0.5**	**$295.3**
Impacts	**973.2**	**3,526.8**	**57.5**	**$1,280.8**
Codes, Standards & Regulations (at generation)	259.1	979.2	72.9	-
Interactive Effects	-	-	-15.8	-
Program Support	-	-	-	$86.4
Demand Side Management Plan - 2016/17 - 2030/31	**1,232**	**4,506**	**115**	**$1,367**

2016 Demand Side Management Plan
Winter Capacity Savings (MW)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	MW at Generation 2030/31	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	0.1	0.3	0.7	1.0	1.4	2.2	2.9	3.5	4.2	4.7	5.3	5.8	6.4	6.9	7.3	8	
Home Insulation Program	1.8	3.3	4.7	6.0	7.2	8.3	9.4	10.3	11.3	12.1	12.8	12.8	12.8	12.8	12.8	15	
Affordable Energy Program	1.2	2.2	3.2	4.1	4.7	5.2	5.8	6.2	6.7	7.1	7.4	7.7	8.0	8.2	8.5	10	
Water and Energy Saver Program	0.7	1.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2	
Refrigerator Retirement Program	1.1	2.1	2.9	3.6	4.2	4.7	4.7	4.7	4.7	4.7	3.7	2.9	2.2	1.5	0.8	1	
Drain Water Heat Recovery Initiative	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Residential LED Lighting Program	5.7	7.7	8.9	8.3	7.9	7.3	6.8	6.2	5.7	5.2	5.0	4.8	4.6	4.4	4.3	5	
Community Geothermal Program	1.2	2.8	4.4	6.2	8.0	9.8	12.2	14.1	15.7	17.4	19.5	21.0	21.7	22.0	22.0	25	
Appliances	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	
HRV Controls	0.5	1.1	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	2	
Power Bars	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Smart Thermostats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	
Plug-in Timers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Community Energy Plan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	12.6	21.2	28.7	33.1	37.3	41.5	45.6	49.0	52.1	55.1	57.7	58.9	59.6	59.7	59.5	68	7%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.2	0.3	0.5	0.7	0.8	1.0	1.2	1.3	1.5	1.6	1.8	1.9	2.1	2.2	2.4	3	
Power Smart PAYS Financing	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	2	
Residential Earth Power Loan	0.2	0.3	0.5	0.6	0.7	0.8	1.0	1.3	1.8	2.3	2.9	3.5	4.2	5.0	5.8	7	
Subtotal	0.4	0.9	1.3	1.7	2.0	2.5	2.9	3.5	4.2	4.9	5.8	6.7	7.6	8.6	9.7	11	1%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	11.1	22.5	34.4	44.4	53.5	62.3	71.1	79.6	87.3	94.8	102.0	109.8	117.9	126.3	133.8	153	
LED Roadway Lighting Conversion Program	1.4	2.8	4.4	6.1	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	7	
Commercial Building Envelope - Windows Program	0.4	0.7	1.0	1.4	1.8	2.3	2.7	3.2	3.6	4.2	4.8	5.4	6.0	6.6	7.2	8	
Commercial Building Envelope - Insulation Program	1.2	2.3	3.1	3.9	4.7	5.6	6.4	7.2	8.1	8.9	9.7	10.6	11.4	12.3	13.1	15	
Commercial Geothermal Program	0.3	0.8	1.4	2.2	3.2	4.3	5.5	6.7	7.9	9.2	10.6	12.0	13.5	14.9	16.4	19	
Commercial HVAC Program - Chillers (Water-Cooled)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Commercial HVAC Program - CO2 Sensors	0.3	0.7	1.1	1.5	1.9	2.4	2.8	3.3	3.3	3.3	3.2	3.0	2.8	2.6	2.4	3	
Commercial HVAC Program - HRVs	0.1	0.4	0.8	1.4	2.1	2.9	3.9	5.0	6.4	7.8	9.4	11.2	13.1	15.1	17.3	20	
Commercial HVAC Program - Air Cooled Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Commercial Custom Measures Program	0.3	0.7	1.1	1.5	1.9	2.3	2.7	3.2	3.6	4.1	4.6	5.2	5.8	6.4	7.1	8	
Commercial Building Optimization Program	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.8	2.0	2.2	2.4	2.6	2.8	3	
New Buildings Program	0.7	2.6	3.3	4.3	5.5	7.0	10.2	13.5	16.7	20.0	23.2	26.5	29.8	33.0	36.3	41	
Commercial Refrigeration Program	0.7	1.4	2.1	2.8	3.2	3.5	3.9	4.3	4.7	5.1	5.6	6.1	6.6	7.2	7.7	9	
Commercial Kitchen Appliance Program	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0	
Network Energy Management Program	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Internal Retrofit Program	0.3	0.5	0.7	0.9	1.5	2.0	2.4	2.5	2.6	2.7	2.7	2.8	2.9	3.0	3.0	3	
Power Smart Shops	0.7	1.3	2.0	2.5	3.1	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	4	
Power Smart Energy Manager	-	-	0.1	0.3	0.6	0.9	1.2	1.6	1.9	2.2	2.5	2.8	3.0	3.1	3.1	4	
Race to Reduce	0.4	0.7	0.9	1.0	0.7	-	-	-	-	-	-	-	-	-	-	-	
Parking Lot Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	18.1	37.8	57.0	75.0	91.2	106.2	124.0	141.2	157.5	174.0	190.3	207.4	225.1	242.9	260.0	296	30%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	1.9	4.2	6.8	9.7	13.0	16.2	19.5	22.7	26.0	29.2	32.5	35.7	38.9	42.2	45.4	50	
Subtotal	1.9	4.2	6.8	9.7	13.0	16.2	19.5	22.7	26.0	29.2	32.5	35.7	38.9	42.2	45.4	50	5%
ENERGY EFFICIENCY SUBTOTAL	33.0	64.1	93.8	119.5	143.5	166.4	192.0	216.4	239.8	263.2	286.2	308.7	331.2	353.5	374.6	425	44%
LOAD MANAGEMENT																	
Curtailable Rate Program	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	160	
LOAD MANAGEMENT SUBTOTAL	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	160	16%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	11.1	12.6	15.1	19.1	29.1	39.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	51	
Customer Sited Load Displacement	11.3	17.6	33.3	53.0	56.5	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	66	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	22.4	30.2	48.4	72.1	85.6	99.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5	117	12%
CONSERVATION RATES																	
Conservation Rates - Residential	-	-	3.1	10.8	11.9	13.1	14.4	15.9	16.1	16.2	16.4	16.6	16.8	17.0	17.2	20	
Conservation Rates - Commercial	-	-	-	5.2	11.3	15.3	16.5	17.7	19.0	20.3	21.6	22.9	24.3	25.7	27.1	31	
CONSERVATION RATES SUBTOTAL	-	-	3.1	16.0	23.2	28.4	30.9	33.6	35.1	36.5	38.0	39.6	41.1	42.7	44.3	51	5%
FUEL CHOICE																	
Fuel Choice	-	25.5	51.1	76.6	102.2	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	146	
FUEL CHOICE SUBTOTAL	-	25.5	51.1	76.6	102.2	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	146	15%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Residential Future Opportunities	-	-	-	-	1.5	3.0	4.6	6.1	7.6	9.1	10.6	12.1	13.7	15.2	16.7	19	
Residential Solar Photovoltaics Program (PV)	-	-	-	-	0.0	0.0	0.1	0.1	0.2	0.4	0.7	1.1	1.6	2.2	2.8	3	
Residential Solar Thermal Program - Water Heating	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Residential Solar Thermal Program - Pool Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Commercial Future Opportunities	-	-	-	-	1.5	3.0	4.6	6.1	7.6	9.1	10.6	12.1	13.7	15.2	16.7	19	
Commercial Solar Photovoltaics Program (PV)	-	-	-	-	0.1	0.2	0.5	1.0	1.8	3.0	4.4	6.2	8.3	10.6	12.9	15	
Commercial Variable Speed and Frequency Drives	-	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	
Industrial Future Opportunities	-	-	-	-	1.6	3.1	4.7	6.3	7.9	9.4	11.0	12.6	14.2	15.7	17.3	19	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	-	0.0	0.0	0.0	4.7	9.5	14.4	19.7	25.2	31.1	37.5	44.3	51.5	59.0	66.5	75	8%
Impacts (at meter)	200	265	341	429	504	577	617	649	679	710	741	772	803	834	865		
Impacts (at generation)	222	295	381	480	565	647	692	729	763	798	833	868	903	939	973	973	100%
Codes, Standards & Regulations (at meter)	16	37	53	73	87	97	108	118	127	145	162	186	202	215	227		
Codes, Standards & Regulations (at generation)	18	42	60	83	99	111	123	134	145	165	184	212	231	245	259	259	
POWER SMART 2016 to 2030 Impacts (at meter)	216	302	394	503	591	674	724	767	807	855	903	958	1,005	1,050	1,092		
POWER SMART 2016 to 2030 Impacts (at generation)	240	337	442	564	664	758	815	863	908	963	1,017	1,080	1,134	1,184	1,232	1,232	
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	313	313	313	313	313	313	312	311	309	307	307	307	307	307	307		
Incentive Based Program Impacts (at generation)	353	353	353	353	353	353	352	350	348	346	346	346	346	346	346	346	
Customer Service Initiatives Program Impacts (at meter)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
Customer Service Initiatives Program Impacts (at generation)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	
Discontinued Programs (at meter)	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60		
Discontinued Programs (at generation)	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	
Impacts of Codes & Standards (at meter)	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178		
Impacts of Codes & Standards (at generation)	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	
TOTAL MW (at meter)	**777**	**862**	**955**	**1,063**	**1,151**	**1,234**	**1,284**	**1,325**	**1,363**	**1,410**	**1,458**	**1,513**	**1,560**	**1,604**	**1,647**		
TOTAL MW (at generation)	**874**	**971**	**1,076**	**1,198**	**1,298**	**1,392**	**1,448**	**1,495**	**1,538**	**1,591**	**1,645**	**1,708**	**1,762**	**1,812**	**1,860**	1,860	

Note: May not add up due to rounding.

2016 Demand Side Management Plan
Annual Energy Savings (GW.h)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	GW.h at Generation 2030/31	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	0.3	0.9	1.8	2.7	3.7	5.4	6.8	8.2	9.5	10.7	11.8	13.0	14.0	15.1	16.0	18	
Home Insulation Program	3.5	6.6	9.4	12.0	14.4	16.7	18.8	20.7	22.5	24.2	25.7	25.7	25.7	25.7	25.7	29	
Affordable Energy Program	2.8	5.2	7.7	10.1	11.7	13.2	14.6	16.0	17.4	18.6	19.4	20.1	20.8	21.5	22.1	25	
Water and Energy Saver Program	4.1	8.1	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	13	
Refrigerator Retirement Program	11.0	20.6	28.5	34.7	40.9	45.6	45.6	45.6	45.6	45.6	36.2	28.2	21.5	14.5	7.6	9	
Drain Water Heat Recovery Initiative	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	
Residential LED Lighting Program	17.9	24.4	28.1	26.2	25.0	23.3	21.5	19.8	18.1	16.3	15.8	15.2	14.7	14.1	13.5	15	
Community Geothermal Program	2.4	5.5	8.9	12.4	15.9	19.5	24.4	28.1	31.4	34.7	39.1	42.0	43.4	43.9	43.9	50	
Appliances	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0	
HRV Controls	1.4	2.8	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	5	
Power Bars	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Smart Thermostats	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0	
Plug-in Timers	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	
Community Energy Plan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	44.4	75.0	100.8	114.6	128.0	140.0	148.2	154.9	161.0	166.6	164.4	160.6	156.6	151.2	145.3	166	5%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.3	0.7	1.0	1.3	1.6	2.0	2.3	2.6	2.9	3.2	3.5	3.8	4.1	4.4	4.7	5	
Power Smart PAYS Financing	0.2	0.4	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.6	2.8	3.0	3	
Residential Earth Power Loan	0.4	0.7	1.0	1.3	1.6	2.2	3.0	4.1	5.4	7.1	8.8	10.6	12.7	15.1	17.7	20	
Subtotal	0.9	1.8	2.7	3.5	4.3	5.4	6.8	8.4	10.2	12.3	14.5	16.9	19.5	22.3	25.3	29	1%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	44.4	90.4	137.1	177.7	215.4	251.2	287.6	322.2	353.9	385.2	414.9	447.1	480.9	515.4	546.7	623	
LED Roadway Lighting Conversion Program	9.4	18.9	29.8	40.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	49	
Commercial Building Envelope - Windows Program	1.4	2.3	3.4	4.6	5.9	7.3	8.8	10.2	11.7	13.3	15.0	16.8	18.6	20.3	22.1	25	
Commercial Building Envelope - Insulation Program	2.6	5.2	6.9	8.8	10.7	12.5	14.4	16.3	18.2	20.1	22.0	24.0	25.9	27.8	29.7	34	
Commercial Geothermal Program	0.7	1.6	2.8	4.4	6.5	8.6	11.0	13.3	15.8	18.4	21.2	24.0	26.9	29.9	32.8	37	
Commercial HVAC Program - Chillers (Water-Cooled)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1	
Commercial HVAC Program - CO2 Sensors	0.4	1.1	1.8	2.5	3.2	3.9	4.7	5.5	5.5	5.5	5.3	5.0	4.6	4.2	3.9	4	
Commercial HVAC Program - HRVs	0.2	0.7	1.6	2.8	4.3	6.0	8.0	10.3	13.0	16.0	19.3	22.9	26.7	30.9	35.3	40	
Commercial HVAC Program - Air Cooled Chillers	-	0.8	2.0	3.3	4.8	6.2	7.8	9.5	11.2	13.0	14.7	16.4	18.1	19.8	21.5	24	
Commercial Custom Measures Program	1.5	3.2	4.9	6.6	8.3	10.0	11.8	13.7	15.8	17.8	20.0	22.6	25.3	28.1	30.8	35	
Commercial Building Optimization Program	0.1	0.7	1.5	2.4	3.4	4.3	5.4	6.5	7.6	8.8	10.0	10.9	11.9	12.9	13.8	16	
New Buildings Program	2.5	8.7	11.2	14.4	18.5	23.5	34.4	45.3	56.3	67.2	78.2	89.1	100.1	111.0	121.9	139	
Commercial Refrigeration Program	6.4	13.3	20.8	27.3	29.9	32.5	35.1	37.9	41.2	44.3	47.6	51.2	55.0	58.9	62.4	71	
Commercial Kitchen Appliance Program	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1	
Network Energy Management Program	0.1	0.3	0.6	0.6	0.6	0.6	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0	
Internal Retrofit Program	1.7	3.0	4.5	5.8	8.0	9.5	11.1	11.6	12.2	12.8	13.3	13.8	14.3	14.8	15.3	17	
Power Smart Shops	2.5	5.0	7.5	9.0	10.6	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.0	12	
Power Smart Energy Manager	-	-	0.5	1.4	2.7	4.1	5.4	6.8	8.1	9.5	10.9	12.2	13.1	13.6	13.6	15	
Race to Reduce	3.8	6.1	7.6	8.8	6.2	-	-	-	-	-	-	-	-	-	-	-	
Parking Lot Controller	1.6	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	3	
Subtotal	81.0	165.5	248.4	325.2	385.6	438.1	503.6	567.3	628.7	690.0	750.5	814.1	879.6	945.6	1,007.8	1,149	33%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	15.5	33.5	54.1	77.3	103.1	128.9	154.7	180.4	206.2	232.0	257.8	283.5	309.3	335.1	360.9	397	
Subtotal	15.5	33.5	54.1	77.3	103.1	128.9	154.7	180.4	206.2	232.0	257.8	283.5	309.3	335.1	360.9	397	11%
ENERGY EFFICIENCY SUBTOTAL	141.7	275.8	406.0	520.6	621.1	712.4	813.3	911.1	1,006.0	1,100.9	1,187.2	1,275.1	1,365.0	1,454.2	1,539.3	1,740	49%
LOAD MANAGEMENT																	
Curtailable Rate Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
LOAD MANAGEMENT SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	29.5	34.8	41.8	48.8	66.3	84.5	96.7	96.7	96.7	96.7	96.7	96.7	96.7	96.7	96.7	106	
Customer Sited Load Displacement	83.5	122.5	254.7	403.1	430.7	458.3	458.3	458.3	458.3	458.3	458.3	458.3	458.3	458.3	458.3	504	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	113.1	157.3	296.5	451.9	497.0	542.8	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	611	17%
CONSERVATION RATES																	
Conservation Rates - Residential	-	-	25.8	90.2	99.2	109.1	120.0	132.0	133.6	135.2	136.8	138.4	140.1	141.7	143.4	163	
Conservation Rates - Commercial	-	-	-	43.2	94.2	127.5	137.5	147.7	158.1	168.7	179.6	190.7	202.1	213.7	225.5	257	
CONSERVATION RATES SUBTOTAL	-	-	25.8	133.4	193.4	236.6	257.5	279.7	291.7	303.9	316.4	329.1	342.1	355.4	368.9	421	12%
FUEL CHOICE																	
Fuel Choice	-	51.1	102.2	153.3	204.4	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	291	
FUEL CHOICE SUBTOTAL	-	51.1	102.2	153.3	204.4	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	255.5	291	8%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	-	0.2	0.5	1.0	1.5	2.1	2.8	3.6	4.5	5.5	6.5	7	
Residential Future Opportunities	-	-	-	-	7.3	14.6	21.9	29.2	36.5	43.9	51.2	58.5	65.8	73.1	80.4	92	
Residential Solar Photovoltaics Program (PV)	-	-	-	-	0.1	0.2	0.6	1.2	2.5	4.8	8.1	12.5	18.0	24.3	30.9	35	
Residential Solar Thermal Program - Water Heating	-	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0	
Residential Solar Thermal Program - Pool Heating	-	0.0	0.1	0.2	0.2	0.3	0.4	0.6	0.7	0.9	1.1	1.3	1.6	1.9	2.3	3	
Commercial Future Opportunities	-	-	-	-	7.3	14.6	21.9	29.2	36.5	43.9	51.2	58.5	65.8	73.1	80.4	92	
Commercial Solar Photovoltaics Program (PV)	-	-	-	-	0.7	2.0	4.8	9.8	17.3	27.9	41.6	58.7	78.4	100.0	121.7	139	
Commercial Variable Speed and Frequency Drives	-	0.1	0.6	1.1	1.5	1.9	2.2	2.6	2.9	3.2	3.4	3.6	3.8	4.0	4.2	5	
Industrial Future Opportunities	-	-	-	-	7.6	15.2	22.7	30.3	37.9	45.5	53.0	60.6	68.2	75.8	83.3	92	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	-	0.2	0.7	1.3	24.8	49.3	75.4	104.2	136.2	172.2	212.6	257.6	306.3	358.0	410.0	464	13%
Impacts (at meter)	255	484	831	1,261	1,541	1,797	1,957	2,105	2,244	2,388	2,527	2,672	2,824	2,978	3,129		
Impacts (at generation)	285	544	934	1,416	1,732	2,021	2,201	2,370	2,527	2,689	2,846	3,010	3,182	3,356	3,527	3,527	100%
Codes, Standards & Regulations (at meter)	64	142	204	282	338	386	430	473	514	581	638	715	771	816	859		
Codes, Standards & Regulations (at generation)	74	161	232	322	385	440	491	539	585	662	728	815	879	930	979	979	
POWER SMART 2016 to 2030 Impacts (at meter)	319	626	1,035	1,543	1,879	2,182	2,387	2,578	2,758	2,968	3,165	3,387	3,595	3,794	3,988		
POWER SMART 2016 to 2030 Impacts (at generation)	359	706	1,166	1,738	2,118	2,460	2,692	2,909	3,112	3,351	3,573	3,825	4,061	4,287	4,506	4,506	
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	1,448	1,448	1,448	1,448	1,447	1,447	1,436	1,426	1,416	1,394	1,394	1,394	1,394	1,394	1,394		
Incentive Based Program Impacts (at generation)	1,628	1,628	1,628	1,628	1,627	1,627	1,615	1,603	1,591	1,566	1,566	1,566	1,566	1,566	1,566	1,566	
Customer Service Initiatives Program Impacts (at meter)	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29		
Customer Service Initiatives Program Impacts (at generation)	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	
Discontinued Programs (at meter)	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368		
Discontinued Programs (at generation)	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	
Impacts of Codes & Standards (at meter)	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731		
Impacts of Codes & Standards (at generation)	833	833	833	833	833	833	833	833	833	833	833	833	833	833	833	833	
TOTAL GW.h (at meter)	**2,895**	**3,202**	**3,611**	**4,119**	**4,454**	**4,757**	**4,951**	**5,132**	**5,302**	**5,490**	**5,686**	**5,908**	**6,116**	**6,315**	**6,509**		
TOTAL GW.h (at generation)	**3,270**	**3,617**	**4,077**	**4,649**	**5,027**	**5,370**	**5,589**	**5,794**	**5,986**	**6,199**	**6,422**	**6,674**	**6,909**	**7,135**	**7,355**	**7,355**	

Note: May not add up due to rounding.

2016 Demand Side Management Plan
Annual Utility Costs (000's $)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	$292	$459	$757	$901	$580	-	-	-	-	-	-	-	-	-	-	$2,989	
Home Insulation Program	$1,679	$1,493	$1,429	$1,355	$1,251	$1,168	$1,130	$1,012	$977	$956	$818	$174	-	-	-	$13,443	
Affordable Energy Program	$2,096	$2,033	$2,019	$2,020	$1,534	$1,527	$1,524	$1,525	$1,530	$1,515	$1,424	$1,435	$1,448	$1,462	$1,478	$24,570	
Water and Energy Saver Program	$1,199	$1,353	$1,242	-	-	-	-	-	-	-	-	-	-	-	-	$3,794	
Refrigerator Retirement Program	$1,911	$1,602	$1,469	$1,178	$1,228	$988	$47	-	-	-	-	-	-	-	-	$8,423	
Drain Water Heat Recovery Initiative	$91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$91	
Residential LED Lighting Program	$3,008	$2,561	$1,870	-	-	-	-	-	-	-	-	-	-	-	-	$7,438	
Community Geothermal Program	$1,105	$1,357	$1,563	$1,668	$1,679	$1,764	$2,280	$1,891	$1,719	$1,809	$2,257	$1,694	$1,084	$676	-	$22,546	
Appliances	$363	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$363	
HRV Controls	$419	$434	$372	-	-	-	-	-	-	-	-	-	-	-	-	$1,225	
Power Bars	$9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$9	
Smart Thermostats	$53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$53	
Plug-in Timers	$26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$26	
Community Energy Plan	$62	$118	$120	$123	$125	$81	$82	$84	$86	$88	$90	$92	$93	$95	$97	$1,437	
Subtotal	$12,312	$11,411	$10,842	$7,245	$6,397	$5,528	$5,064	$4,513	$4,312	$4,367	$4,589	$3,395	$2,625	$2,234	$1,576	$86,409	8%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Smart PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$8,257	$8,145	$8,209	$8,499	$8,227	$8,085	$8,291	$8,224	$7,851	$7,787	$7,842	$8,124	$8,568	$8,853	$8,304	$123,265	
LED Roadway Lighting Conversion Program	$10,993	$9,858	$10,957	$10,801	$1,778	-	-	-	-	-	-	-	-	-	-	$44,388	
Commercial Building Envelope - Windows Program	$501	$483	$512	$564	$603	$643	$657	$671	$685	$759	$811	$833	$850	$868	$887	$10,326	
Commercial Building Envelope - Insulation Program	$799	$722	$664	$709	$724	$738	$754	$775	$791	$808	$825	$848	$865	$884	$902	$11,808	
Commercial Geothermal Program	$461	$569	$622	$785	$983	$1,028	$1,099	$1,169	$1,212	$1,274	$1,384	$1,423	$1,518	$1,563	$1,617	$16,705	
Commercial HVAC Program - Chillers (Water-Cooled)	$192	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$192	
Commercial HVAC Program - CO2 Sensors	$181	$187	$200	$204	$213	$218	$225	$232	$2	$2	$2	$2	$2	$2	$2	$1,675	
Commercial HVAC Program - HRVs	$475	$768	$888	$957	$1,023	$1,093	$1,168	$1,340	$1,433	$1,533	$1,735	$1,840	$1,951	$2,201	$2,312	$20,716	
Commercial HVAC Program - Air Cooled Chillers	-	$463	$605	$655	$708	$763	$820	$879	$940	$960	$980	$1,001	$1,022	$1,043	$1,066	$11,903	
Commercial Custom Measures Program	$404	$459	$469	$479	$489	$499	$535	$573	$612	$625	$666	$795	$841	$858	$876	$9,180	
Commercial Building Optimization Program	$158	$174	$206	$217	$228	$233	$244	$250	$262	$268	$281	$287	$301	$329	$336	$3,772	
New Buildings Program	$1,049	$1,770	$1,267	$1,570	$1,884	$2,261	$549	$561	-	-	-	-	-	-	-	$10,911	
Commercial Refrigeration Program	$450	$720	$763	$742	$722	$851	$863	$924	$1,000	$909	$1,081	$1,097	$1,214	$1,163	$1,030	$13,530	
Commercial Kitchen Appliance Program	$78	$29	-	-	-	-	-	-	-	-	-	-	-	-	-	$107	
Network Energy Management Program	$27	$44	$55	-	-	-	-	-	-	-	-	-	-	-	-	$127	
Internal Retrofit Program	$935	$980	$977	$848	$1,270	$967	$988	$434	$443	$452	$419	$428	$437	$446	$456	$10,480	
Power Smart Shops	$674	$619	$632	$635	$649	$240	-	-	-	-	-	-	-	-	-	$3,449	
Power Smart Energy Manager	$78	$167	$289	$320	$249	$202	$206	$210	$214	$219	$101	$44				$2,204	
Race to Reduce	$128	$131	$134	$137	-	-	-	-	-	-	-	-	-	-	-	$530	
Parking Lot Controller	$358	$169	-	-	-	-	-	-	-	-	-	-	-	-	-	$527	
Subtotal	$26,200	$26,457	$27,449	$28,122	$19,748	$17,820	$16,399	$16,240	$15,445	$15,595	$16,126	$16,720	$17,553	$18,171	$17,748	$295,795	27%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	$3,310	$5,129	$6,592	$7,359	$8,154	$8,327	$8,502	$8,682	$8,865	$9,053	$9,244	$9,439	$9,639	$9,842	$10,050	$122,187	
Subtotal	$3,310	$5,129	$6,592	$7,359	$8,154	$8,327	$8,502	$8,682	$8,865	$9,053	$9,244	$9,439	$9,639	$9,842	$10,050	$122,187	11%
ENERGY EFFICIENCY SUBTOTAL	$41,822	$42,996	$44,883	$42,725	$34,300	$31,675	$29,965	$29,435	$28,622	$29,015	$29,960	$29,555	$29,817	$30,247	$29,374	$504,391	45%
LOAD MANAGEMENT																	
Curtailable Rate Program	$6,112	$6,241	$6,373	$6,508	$6,645	$6,786	$6,929	$7,075	$7,225	$7,378	$7,533	$7,693	$7,855	$8,021	$8,190	$106,566	
LOAD MANAGEMENT SUBTOTAL	$6,112	$6,241	$6,373	$6,508	$6,645	$6,786	$6,929	$7,075	$7,225	$7,378	$7,533	$7,693	$7,855	$8,021	$8,190	$106,566	10%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$848	$1,664	$2,702	$3,942	$10,120	$10,733	$7,475	$8	$9	$9	$9	$9	$9	$10	-	$37,547	
Customer Sited Load Displacement	$3,911	$12,235	$27,850	$22,404	$5,284	$6,207	$458	$420	$426	$433	$442	$452	$461	$451	$412	$81,846	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$4,758	$13,898	$30,552	$26,346	$15,404	$16,941	$7,932	$428	$435	$442	$451	$461	$471	$461	$412	$119,393	11%
CONSERVATION RATES																	
Conservation Rates - Residential	-	$2,042	$2,085	$2,129	$1,631	$1,110	$1,134	$579	$591	$603	$308	$315	$321	$328	-	$13,177	
Conservation Rates - Commercial	-	$1,532	$2,085	$2,662	$2,718	$1,110	$1,134	$1,158	$1,182	$1,207	$616	$629	$643	$656	-	$17,331	
CONSERVATION RATES SUBTOTAL	-	$3,574	$4,171	$4,791	$4,349	$2,220	$2,267	$1,736	$1,773	$1,810	$924	$944	$964	$984	-	$30,509	3%
FUEL CHOICE																	
Fuel Choice	-	$10,315	$10,524	$10,746	$10,973	$11,205	-	-	-	-	-	-	-	-	-	$53,765	
FUEL CHOICE SUBTOTAL	-	$10,315	$10,524	$10,746	$10,973	$11,205	-	-	-	-	-	-	-	-	-	$53,765	5%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	$40	$116	$158	$185	$206	$223	$252	$289	$314	$347	$354	$2,485	
Residential Future Opportunities	-	-	-	-	$4,131	$4,219	$4,308	$4,399	$4,492	$4,587	$4,683	$4,782	$4,883	$4,987	$5,092	$50,563	
Residential Solar Photovoltaics Program (PV)	-	-	-	$49	$162	$246	$414	$777	$1,441	$2,507	$3,774	$4,984	$6,284	$7,377	$7,854	$35,870	
Residential Solar Thermal Program - Water Heating	$5	$51	$50	$53	$57	$58	$24	-	-	-	-	-	-	-	-	$299	
Residential Solar Thermal Program - Pool Heating	$2	$19	$19	$20	$22	$22	$24	$26	$28	$30	$33	$35	$40	$43	$48	$410	
Commercial Future Opportunities	-	-	-	-	$4,458	$4,552	$4,648	$4,746	$4,846	$4,949	$5,053	$5,160	$5,269	$5,380	$5,494	$54,554	
Commercial Solar Photovoltaics Program (PV)	-	-	-	$160	$557	$1,011	$1,895	$3,360	$5,058	$7,297	$9,594	$12,167	$14,240	$15,966	$16,304	$87,609	
Commercial Variable Speed and Frequency Drives	$8	$142	$187	$191	$191	$193	$192	$196	$198	$200	$197	$201	$205	$209	$214	$2,723	
Industrial Future Opportunities	-	-	-	-	$4,892	$4,996	$5,101	$5,209	$5,319	$5,431	$5,546	$5,663	$5,783	$5,905	$6,030	$59,877	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	$15	$212	$257	$473	$14,510	$15,413	$16,765	$18,897	$21,589	$25,222	$29,133	$33,282	$37,018	$40,215	$41,390	$294,388	27%
Subtotal of Programs	$52,708	$77,237	$96,760	$91,590	$86,182	$84,240	$63,858	$57,573	$59,644	$63,867	$68,001	$71,934	$76,124	$79,928	$79,365	$1,109,011	100%
Program Support	$4,129	$4,033	$3,956	$4,039	$4,124	$4,212	$4,301	$4,391	$4,484	$4,579	$4,676	$4,774	$4,875	$4,978	$5,083	$66,635	
Total Utility Costs (2016 to 2030)	$56,837	$81,270	$100,716	$95,629	$90,307	$88,451	$68,159	$61,964	$64,129	$68,446	$72,677	$76,708	$80,999	$84,906	$84,449	$1,175,646	
Total Committed to Date																$509,592	
TOTAL UTILITY COSTS (1989 to 2030)	**$56,837**	**$81,270**	**$100,716**	**$95,629**	**$90,307**	**$88,451**	**$68,159**	**$61,964**	**$64,129**	**$68,446**	**$72,677**	**$76,708**	**$80,999**	**$84,906**	**$84,449**	**$1,685,237**	

Note: May not add up due to rounding.

2016 Demand Side Management Plan
Annual Administration Costs (000's $)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	$188	$229	$299	$375	$112	-	-	-	-	-	-	-	-	-	-	$1,204	
Home Insulation Program	$795	$748	$723	$686	$617	$566	$557	$468	$459	$462	$347	$174	-	-	-	$6,600	
Affordable Energy Program	$1,037	$1,002	$1,023	$1,044	$1,005	$1,026	$1,048	$1,070	$1,092	$1,104	$1,081	$1,104	$1,127	$1,151	$1,175	$16,091	
Water and Energy Saver Program	$891	$1,098	$1,016	-	-	-	-	-	-	-	-	-	-	-	-	$3,004	
Refrigerator Retirement Program	$1,461	$1,244	$1,164	$939	$983	$798	$47	-	-	-	-	-	-	-	-	$6,636	
Drain Water Heat Recovery Initiative	$21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$21	
Residential LED Lighting Program	$1,024	$949	$813	-	-	-	-	-	-	-	-	-	-	-	-	$2,785	
Community Geothermal Program	$368	$377	$376	$384	$392	$401	$412	$418	$426	$435	$447	$453	$458	$465	-	$5,812	
Appliances	$143	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$143	
HRV Controls	$66	$86	$88	-	-	-	-	-	-	-	-	-	-	-	-	$240	
Power Bars	$8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$8	
Smart Thermostats	$18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$18	
Plug-in Timers	$15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$15	
Community Energy Plan	$62	$118	$120	$123	$125	$81	$82	$84	$86	$88	$90	$92	$93	$95	$97	$1,437	
Subtotal	$6,095	$5,851	$5,623	$3,551	$3,235	$2,872	$2,147	$2,040	$2,062	$2,089	$1,964	$1,822	$1,679	$1,712	$1,273	$44,014	17%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Smart PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$2,398	$2,673	$2,729	$2,787	$2,846	$2,906	$2,967	$3,030	$3,094	$3,159	$3,226	$3,294	$3,364	$3,435	$3,508	$45,417	
LED Roadway Lighting Conversion Program	$433	$401	$399	$244	$249	-	-	-	-	-	-	-	-	-	-	$1,727	
Commercial Building Envelope - Windows Program	$272	$305	$312	$320	$327	$334	$341	$348	$355	$363	$372	$381	$389	$397	$405	$5,220	
Commercial Building Envelope - Insulation Program	$334	$310	$331	$352	$360	$367	$375	$383	$391	$400	$408	$417	$425	$434	$444	$5,732	
Commercial Geothermal Program	$234	$234	$254	$249	$270	$273	$271	$294	$288	$300	$328	$313	$320	$340	$334	$4,303	
Commercial HVAC Program - Chillers (Water-Cooled)	$125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$125	
Commercial HVAC Program - CO2 Sensors	$124	$112	$116	$117	$121	$122	$124	$127	$2	$2	$2	$2	$2	$2	$2	$977	
Commercial HVAC Program - HRVs	$93	$66	$64	$65	$66	$68	$69	$71	$72	$74	$75	$77	$79	$80	$82	$1,102	
Commercial HVAC Program - Air Cooled Chillers	-	$95	$79	$80	$82	$83	$85	$87	$89	$91	$93	$95	$97	$99	$101	$1,255	
Commercial Custom Measures Program	$109	$111	$113	$116	$118	$121	$123	$126	$129	$131	$134	$137	$140	$143	$146	$1,896	
Commercial Building Optimization Program	$149	$137	$139	$142	$145	$148	$152	$155	$158	$161	$165	$168	$172	$175	$179	$2,346	
New Buildings Program	$589	$449	$458	$468	$478	$538	$549	$561	-	-	-	-	-	-	-	$4,088	
Commercial Refrigeration Program	$118	$323	$330	$337	$344	$352	$359	$367	$374	$382	$390	$399	$407	$416	$424	$5,322	
Commercial Kitchen Appliance Program	$9	$9	-	-	-	-	-	-	-	-	-	-	-	-	-	$17	
Network Energy Management Program	$20	$22	$25	-	-	-	-	-	-	-	-	-	-	-	-	$67	
Internal Retrofit Program	$307	$282	$288	$294	$185	$189	$193	$197	$201	$205	$210	$214	$218	$223	$228	$3,433	
Power Smart Shops	$194	$178	$182	$185	$189	$97	-	-	-	-	-	-	-	-	-	$1,024	
Power Smart Energy Manager	$78	$119	$192	$196	$200	$204	$208	$213	$217	$222	$104	$106	$108	$110	-	$2,275	
Race to Reduce	$128	$131	$134	$137	-	-	-	-	-	-	-	-	-	-	-	$530	
Parking Lot Controller	$57	$32	-	-	-	-	-	-	-	-	-	-	-	-	-	$89	
Subtotal	$5,771	$5,990	$6,146	$6,089	$5,981	$5,801	$5,816	$5,957	$5,371	$5,490	$5,507	$5,602	$5,720	$5,854	$5,852	$86,946	33%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	$1,198	$1,645	$1,679	$1,715	$1,751	$1,788	$1,826	$1,864	$1,904	$1,944	$1,985	$2,027	$2,070	$2,114	$2,158	$27,668	
Subtotal	$1,198	$1,645	$1,679	$1,715	$1,751	$1,788	$1,826	$1,864	$1,904	$1,944	$1,985	$2,027	$2,070	$2,114	$2,158	$27,668	11%
ENERGY EFFICIENCY SUBTOTAL	$13,064	$13,485	$13,449	$11,355	$10,967	$10,460	$9,789	$9,861	$9,337	$9,523	$9,456	$9,451	$9,469	$9,679	$9,283	$158,628	61%
LOAD MANAGEMENT																	
Curtailable Rate Program	$4	$4	$4	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5	$70	
LOAD MANAGEMENT SUBTOTAL	$4	$4	$4	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5	$70	0%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$315	$209	$278	$109	$335	$342	$333	$8	$9	$9	$9	$9	$9	$10	-	$1,984	
Customer Sited Load Displacement	$661	$481	$584	$481	$458	$323	$117	$73	$72	$71	$72	$74	$76	$58	$10	$3,610	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$976	$689	$861	$590	$793	$665	$450	$81	$80	$80	$82	$83	$85	$67	$10	$5,594	2%
CONSERVATION RATES																	
Conservation Rates - Residential	-	$2,042	$2,085	$2,129	$1,631	$1,110	$1,134	$579	$591	$603	$308	$315	$321	$328	-	$13,177	
Conservation Rates - Commercial	-	$1,532	$2,085	$2,662	$2,718	$1,110	$1,134	$1,158	$1,182	$1,207	$616	$629	$643	$656	-	$17,331	
CONSERVATION RATES SUBTOTAL	-	$3,574	$4,171	$4,791	$4,349	$2,220	$2,267	$1,736	$1,773	$1,810	$924	$944	$964	$984	-	$30,509	12%
FUEL CHOICE																	
Fuel Choice	-	$684	$689	$704	$719	$734	-	-	-	-	-	-	-	-	-	$3,530	
FUEL CHOICE SUBTOTAL	-	$684	$689	$704	$719	$734	-	-	-	-	-	-	-	-	-	$3,530	1%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	$40	$83	$84	$86	$88	$90	$92	$94	$96	$98	$100	$951	
Residential Future Opportunities	-	-	-	-	$1,631	$1,665	$1,700	$1,736	$1,773	$1,810	$1,849	$1,888	$1,928	$1,968	$2,010	$19,959	
Residential Solar Photovoltaics Program (PV)	-	-	-	$49	$108	$118	$122	$182	$288	$443	$614	$788	$930	$1,089	$1,154	$5,883	
Residential Solar Thermal Program - Water Heating	$5	$43	$42	$43	$43	$44	$24	-	-	-	-	-	-	-	-	$244	
Residential Solar Thermal Program - Pool Heating	$2	$15	$15	$15	$16	$16	$16	$16	$17	$17	$17	$18	$19	$19	$19	$236	
Commercial Future Opportunities	-	-	-	-	$870	$888	$907	$926	$946	$966	$986	$1,007	$1,028	$1,050	$1,072	$10,645	
Commercial Solar Photovoltaics Program (PV)	-	-	-	$160	$163	$167	$170	$174	$177	$302	$308	$315	$321	$328	$335	$2,919	
Commercial Variable Speed and Frequency Drives	$8	$97	$99	$102	$104	$106	$108	$110	$113	$115	$118	$120	$123	$125	$128	$1,575	
Industrial Future Opportunities	-	-	-	-	$1,631	$1,665	$1,700	$1,736	$1,773	$1,810	$1,849	$1,888	$1,928	$1,968	$2,010	$19,959	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	$15	$155	$156	$368	$4,605	$4,751	$4,833	$4,967	$5,174	$5,553	$5,833	$6,116	$6,372	$6,645	$6,828	$62,371	24%
Subtotal of Programs	$14,058	$18,592	$19,330	$17,813	$21,437	$18,836	$17,344	$16,650	$16,370	$16,972	$16,300	$16,600	$16,894	$17,381	$16,126	$260,702	100%
Program Support	$4,129	$4,033	$3,956	$4,039	$4,124	$4,212	$4,301	$4,391	$4,484	$4,579	$4,676	$4,774	$4,875	$4,978	$5,083	$66,635	
Total Administration Costs (2016 to 2030)	$18,187	$22,625	$23,286	$21,852	$25,562	$23,047	$21,644	$21,042	$20,854	$21,550	$20,975	$21,374	$21,770	$22,359	$21,209	$327,337	
Total Committed to Date																$226,268	
TOTAL ADMINISTRATION COSTS (1989 to 2030)	**$18,187**	**$22,625**	**$23,286**	**$21,852**	**$25,562**	**$23,047**	**$21,644**	**$21,042**	**$20,854**	**$21,550**	**$20,975**	**$21,374**	**$21,770**	**$22,359**	**$21,209**	**$553,605**	

Note: May not add up due to rounding.

2016 Demand Side Management Plan
Annual Incentive Costs (000's $)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	$104	$230	$458	$525	$468	-	-	-	-	-	-	-	-	-	-	$1,785	
Home Insulation Program	$884	$745	$706	$669	$635	$603	$573	$545	$519	$494	$471	-	-	-	-	$6,843	
Affordable Energy Program	$1,059	$1,031	$996	$976	$528	$501	$477	$456	$438	$410	$343	$331	$320	$311	$303	$8,479	
Water and Energy Saver Program	$308	$255	$227	-	-	-	-	-	-	-	-	-	-	-	-	$790	
Refrigerator Retirement Program	$450	$358	$305	$240	$245	$190	-	-	-	-	-	-	-	-	-	$1,787	
Drain Water Heat Recovery Initiative	$70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$70	
Residential LED Lighting Program	$1,984	$1,612	$1,057	-	-	-	-	-	-	-	-	-	-	-	-	$4,653	
Community Geothermal Program	$737	$980	$1,187	$1,284	$1,286	$1,363	$1,868	$1,473	$1,293	$1,374	$1,811	$1,242	$625	$211	-	$16,734	
Appliances	$220	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$220	
HRV Controls	$354	$348	$284	-	-	-	-	-	-	-	-	-	-	-	-	$985	
Power Bars	$2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$2	
Smart Thermostats	$35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$35	
Plug-in Timers	$12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$12	
Community Energy Plan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	$6,217	$5,560	$5,219	$3,693	$3,162	$2,656	$2,917	$2,473	$2,249	$2,279	$2,625	$1,573	$946	$522	$303	$42,395	5%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Smart PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$5,859	$5,472	$5,480	$5,712	$5,381	$5,179	$5,323	$5,194	$4,757	$4,627	$4,616	$4,830	$5,204	$5,418	$4,796	$77,847	
LED Roadway Lighting Conversion Program	$10,560	$9,458	$10,558	$10,557	$1,528	-	-	-	-	-	-	-	-	-	-	$42,661	
Commercial Building Envelope - Windows Program	$228	$178	$199	$244	$276	$310	$316	$323	$330	$396	$439	$452	$462	$472	$481	$5,106	
Commercial Building Envelope - Insulation Program	$466	$412	$333	$356	$364	$371	$378	$391	$400	$408	$417	$431	$440	$449	$459	$6,076	
Commercial Geothermal Program	$227	$334	$368	$537	$712	$755	$828	$875	$923	$973	$1,056	$1,110	$1,198	$1,223	$1,283	$12,403	
Commercial HVAC Program - Chillers (Water-Cooled)	$68	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$68	
Commercial HVAC Program - CO2 Sensors	$57	$75	$84	$88	$92	$96	$101	$105	-	-	-	-	-	-	-	$697	
Commercial HVAC Program - HRVs	$382	$703	$824	$892	$956	$1,025	$1,099	$1,269	$1,361	$1,459	$1,660	$1,763	$1,872	$2,121	$2,230	$19,614	
Commercial HVAC Program - Air Cooled Chillers	-	$368	$526	$575	$626	$679	$735	$792	$851	$869	$887	$906	$925	$945	$965	$10,649	
Commercial Custom Measures Program	$295	$348	$355	$363	$371	$378	$412	$447	$483	$494	$532	$658	$701	$716	$731	$7,284	
Commercial Building Optimization Program	$10	$37	$66	$74	$83	$84	$93	$95	$104	$106	$116	$118	$129	$153	$157	$1,426	
New Buildings Program	$460	$1,321	$809	$1,102	$1,407	$1,724	-	-	-	-	-	-	-	-	-	$6,823	
Commercial Refrigeration Program	$332	$397	$433	$405	$378	$499	$504	$557	$626	$527	$691	$698	$807	$748	$606	$8,208	
Commercial Kitchen Appliance Program	$70	$20	-	-	-	-	-	-	-	-	-	-	-	-	-	$90	
Network Energy Management Program	$7	$22	$30	-	-	-	-	-	-	-	-	-	-	-	-	$59	
Internal Retrofit Program	$628	$698	$689	$554	$1,085	$779	$795	$237	$242	$247	$210	$214	$218	$223	$228	$7,047	
Power Smart Shops	$480	$441	$451	$450	$459	$143	-	-	-	-	-	-	-	-	-	$2,425	
Power Smart Energy Manager	-	$48	$97	$124	$49												
Race to Reduce	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Parking Lot Controller	$301	$137	-	-	-	-	-	-	-	-	-	-	-	-	-	$438	
Subtotal	$20,429	$20,467	$21,303	$22,033	$13,768	$12,020	$10,582	$10,283	$10,074	$10,104	$10,620	$11,119	$11,833	$12,317	$11,896	$208,849	25%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	$2,112	$3,484	$4,913	$5,644	$6,403	$6,538	$6,677	$6,818	$6,962	$7,109	$7,259	$7,412	$7,569	$7,729	$7,892	$94,519	
Subtotal	$2,112	$3,484	$4,913	$5,644	$6,403	$6,538	$6,677	$6,818	$6,962	$7,109	$7,259	$7,412	$7,569	$7,729	$7,892	$94,519	11%
ENERGY EFFICIENCY SUBTOTAL	$28,758	$29,511	$31,435	$31,370	$23,333	$21,215	$20,176	$19,574	$19,285	$19,492	$20,504	$20,104	$20,348	$20,568	$20,091	$345,763	41%
LOAD MANAGEMENT																	
Curtailable Rate Program	$6,108	$6,237	$6,369	$6,504	$6,641	$6,781	$6,925	$7,071	$7,220	$7,373	$7,528	$7,688	$7,850	$8,016	$8,185	$106,496	
LOAD MANAGEMENT SUBTOTAL	$6,108	$6,237	$6,369	$6,504	$6,641	$6,781	$6,925	$7,071	$7,220	$7,373	$7,528	$7,688	$7,850	$8,016	$8,185	$106,496	13%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$533	$1,455	$2,424	$3,833	$9,785	$10,391	$7,142	-	-	-	-	-	-	-	-	$35,563	
Customer Sited Load Displacement	$3,250	$11,754	$27,266	$21,923	$4,826	$5,884	$340	$347	$355	$362	$370	$378	$386	$394	$402	$78,236	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$3,783	$13,209	$29,691	$25,756	$14,611	$16,275	$7,482	$347	$355	$362	$370	$378	$386	$394	$402	$113,799	13%
CONSERVATION RATES																	
Conservation Rates - Residential	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Conservation Rates - Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CONSERVATION RATES SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
FUEL CHOICE																	
Fuel Choice	-	$9,631	$9,835	$10,043	$10,255	$10,471	-	-	-	-	-	-	-	-	-	$50,235	
FUEL CHOICE SUBTOTAL	-	$9,631	$9,835	$10,043	$10,255	$10,471	-	-	-	-	-	-	-	-	-	$50,235	6%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	-	$33	$74	$98	$118	$133	$160	$195	$218	$249	$255	$1,534	
Residential Future Opportunities	-	-	-	-	$2,501	$2,553	$2,607	$2,662	$2,719	$2,776	$2,835	$2,895	$2,956	$3,018	$3,082	$30,604	
Residential Solar Photovoltaics Program (PV)	-	-	-	-	$54	$129	$292	$595	$1,154	$2,064	$3,160	$4,196	$5,354	$6,288	$6,700	$29,986	
Residential Solar Thermal Program - Water Heating	-	$8	$9	$11	$14	$14	-	-	-	-	-	-	-	-	-	$55	
Residential Solar Thermal Program - Pool Heating	-	$4	$4	$5	$6	$7	$8	$9	$11	$13	$15	$18	$21	$24	$29	$174	
Commercial Future Opportunities	-	-	-	-	$3,588	$3,664	$3,741	$3,820	$3,901	$3,983	$4,067	$4,153	$4,241	$4,330	$4,422	$43,910	
Commercial Solar Photovoltaics Program (PV)	-	-	-	-	$394	$844	$1,725	$3,187	$4,881	$6,995	$9,286	$11,853	$13,918	$15,638	$15,969	$84,690	
Commercial Variable Speed and Frequency Drives	-	$45	$88	$90	$87	$87	$84	$86	$85	$85	$79	$81	$82	$84	$86	$1,148	
Industrial Future Opportunities	-	-	-	-	$3,262	$3,331	$3,401	$3,473	$3,546	$3,621	$3,697	$3,776	$3,855	$3,937	$4,020	$39,918	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	-	$56	$101	$105	$9,905	$10,661	$11,932	$13,930	$16,415	$19,669	$23,300	$27,165	$30,646	$33,570	$34,562	$232,017	27%
Subtotal of Programs	$38,649	$58,645	$77,430	$73,777	$64,745	$65,404	$46,515	$40,922	$43,275	$46,896	$51,702	$55,334	$59,229	$62,547	$63,239	$848,309	100%
Program Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Incentive Costs (2016 to 2030)	$38,649	$58,645	$77,430	$73,777	$64,745	$65,404	$46,515	$40,922	$43,275	$46,896	$51,702	$55,334	$59,229	$62,547	$63,239	$848,309	
Total Committed to Date																$282,990	
TOTAL INCENTIVE COSTS (1989 to 2030)	**$38,649**	**$58,645**	**$77,430**	**$73,777**	**$64,745**	**$65,404**	**$46,515**	**$40,922**	**$43,275**	**$46,896**	**$51,702**	**$55,334**	**$59,229**	**$62,547**	**$63,239**	**$1,131,299**	

Note: May not add up due to rounding.

The Public Utilities Board

Report on the

Needs **F**or and **A**lternatives **T**o **(NFAT)**

Review of Manitoba Hydro's Preferred Development Plan

June 2014

Project. To achieve these electricity savings, Manitoba Hydro budgets to spend $822 million, which is less than 8% of the $10.7 billion cost of building Conawapa.[81]

5.4.1. Role of DSM in Resource Planning

A number of witnesses discussed how DSM savings should be treated for resource planning purposes.

Manitoba Hydro provided evidence on how its DSM initiatives fit into its power resource planning process. Referring to the interface as a "combined DSM integrated resource planning process", it begins with resource planning staff indicating a value that represents the value of energy to Manitoba Hydro (currently approximately 7.5 ¢/kWh). This marginal value represents the value of energy that is saved and then exported combined with the avoided cost of new transmission and distribution infrastructure. This value is used to update Manitoba Hydro's Power Smart Plan in relation to economic DSM opportunities based on a total resource cost metric. The revised plan is then provided back to Manitoba Hydro's resource planners for input into the resource planning process.[82]

Elenchus and Mr. Dunsky emphasized that Manitoba Hydro should treat DSM as a resource option from the outset, assessing it in the same manner as investments in traditional resource options such as hydro dams or investments in transmission and distribution. Both suggested that Manitoba Hydro pursue an Integrated Resource Planning (IRP) approach to evaluate supply- and demand-side resources on an equal footing.[83]

Mr. Dunsky further stated that an integrated process helps to ensure that least cost options are fully considered. He maintained that by not treating DSM as a resource option through an IRP approach in its analysis of the possible resource options to meet domestic power needs, Manitoba Hydro has *"de facto excluded the single lowest-cost and lowest-risk resource option available"*[84] and "*risks locking itself into a path of new supply that, as a result, will lock out the much less expensive option of more efficient demand.*"[85]

Manitoba Hydro maintains that it is undertaking integrated resource planning that combines supply and demand options, and that its Power Smart Plan is an integral

[81] Exhibit MH-180, p. 31.
[82] Transcript, pp. 431-434.
[83] Exhibit ERA-2.2, p. 1; Exhibit CAC-19, p. 6.
[84] Exhibit CAC-19, p. 12.
[85] Exhibit CAC-19, p. 16.

both achievable and economic. The Panel agrees with the Consumers' Association of Canada (Manitoba) that Manitoba Hydro did not treat DSM as a stand-alone resource option competitive with other generation options in its resource planning and analyses.

In its resource planning, Manitoba Hydro added DSM to each alternative plan it examined. By doing this, Manitoba Hydro effectively screened out DSM as an independent resource to be evaluated against other generation resources.

Had Manitoba Hydro undertaken a best-practices integrated resource planning effort, DSM would have been incorporated in the NFAT analysis from the beginning.

Thus, to satisfy anticipated load growth to 2028/29, the Preferred Development Plan delivers 2,025 MW of additional capacity at an estimated cost of $18.7 billion. Had the Supplemental 2014 Power Smart Plan DSM measures been treated as a stand-alone and equally weighted resource, and added to the capacity from the Keeyask Project, the total capacity addition would be 1,766 MW at a projected cost, including transmission, of $8.3 billion. This is more than 85% of the net system capacity of the Preferred Development Plan, at a considerably lower cost.

It is clear: DSM must be evaluated as a stand-alone resource in an integrated resource planning process by Manitoba Hydro.

In a time of rapid technological innovation on both the demand and supply side, openness to alternative resources and new technologies will be required. This may involve new methods of saving electricity as well as new methods of generating it, such as wind and solar power. Integrated resource planning provides the analytical framework to evaluate all such energy resource options – hydropower, wind, solar, gas, DSM, or other technologies – on an equal footing. As such, it should be adopted by Manitoba Hydro before any further generating facilities beyond the Keeyask Project are constructed in the future.

DSM Targets

Annual average incremental energy savings in the order of 1.5% (including codes and standards) are achievable and economic. This target contrasts with Manitoba Hydro's 2014-17 Power Smart Plan which forecasts declining future DSM savings. In the Panel's view, it is prudent to assume that DSM savings will continue to be attained and technological advances will present new savings opportunities.

While reliance on on-going incremental DSM savings present a risk that the savings will not be realized, several other North American jurisdictions have successfully achieved

5. The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.

Demand Side Management Plans and Programs

During the NFAT Review hearings, the Panel heard that Demand Side Management initiatives were "game changers." The Panel learned that Demand Side Management can have a profound impact on the need for, and timing of, new energy resources. According to its 2014 Supplementary Power Smart Plan, Manitoba Hydro can achieve 1,136 MW and 3,978 GWh of electricity savings by 2028/29. This would amount to more than 80% of the net system capacity addition from the proposed Conawapa Project.

Successful Demand Side Management initiatives are based on ambitious and achievable targets. In recent years and on an annual basis as a percentage of total demand, Manitoba Hydro's DSM savings have declined to approximately 0.4%, well below the 1.5% to 2% levels seen in many other jurisdictions. Demand Side Management savings in the order of 1.5% (including codes and standards) are achievable and economic.

Manitoba Hydro was formerly recognized as a leader in DSM but has since been surpassed by a number of jurisdictions. The Panel is concerned that the full potential for Demand Side Management will not be realized if the responsibility for Demand Side Management remains within Manitoba Hydro. Commitment, independent action and external monitoring of performance are the demonstrated and proven ingredients of successful DSM programs. Interveners encouraged the Panel to take these steps.

6. The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.

7. The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.

8. The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.

9. The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.

ELECTRIC GENERAL RATE APPLICATION 2015

Manitoba Hydro Undertaking #4

Manitoba Hydro to request ministerial approval to file letter to Public Utilities Board regarding the NFAT Report recommendations.

Response:

The Corporation has received consent from the Minister responsible for Manitoba Hydro to file the letter of July 2, 2014, from the Province of Manitoba to the Manitoba Hydro-Electric Board and Manitoba Hydro with respect to the Public Utilities Board's recommendations on the Needs from and Alternatives To Review.

Please find a copy of this letter attached.

**MINISTER RESPONSIBLE
FOR MANITOBA HYDRO**

Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

JUL 0 2 2014

Mr. William Fraser
Chair
Manitoba Hydro-Electric Board
7 Kronstal Place
Winnipeg MB R2G 3J8

Mr. Scott Thomson
President and CEO
Manitoba Hydro
P.O. Box 815 Stn Main
Winnipeg MB R3C 2P4

Dear Mr. Fraser and Mr. Thomson:

The Public Utilities Board (PUB) Panel submitted its Report on the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Development Plan to Government on Friday, June 20, 2014. We appreciate the significant work and commitment of all Panel members in completing this important review process. The NFAT review was the most thorough financial and economic evaluation of a major industrial development in Manitoba history.

As noted by the PUB Panel, early decisions to develop our Province's rich hydro-electric resources have resulted in many decades of affordable, reliable and renewable electricity for Manitoba families and our growing economy. In more recent times, Manitoba Hydro has greatly enhanced its development model by forging meaningful Aboriginal partnerships over the course of many years, resulting in better environmental stewardship and important socio-economic opportunities and benefits for Aboriginal people. Moving forward, we remain committed to this approach of partnership and reconciliation with Aboriginal people through environmental and resource management, and community and economic development.

We are pleased that the NFAT review has recommended building the next generation of hydro-electric development. The PUB Panel has concluded that new hydro generation is needed in order to meet Manitoba's own power needs and to take advantage of profitable export opportunities. By helping to pay down the cost of new generation, new power export agreements help keep rates low for all Manitobans for the long-term.

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Specifically, the NFAT review has recommended proceeding with immediate construction of Keeyask to meet domestic and export requirements with an advanced in-service date of 2019. Keeyask will be built within the Split Lake Resource Management Area and developed as a ground-breaking partnership between Manitoba Hydro, Tataskweyak First Nation, York Factory First Nation, War Lake Cree Nation and Fox Lake Cree Nation, creating more than 8,000 person-years of employment.

We note that in reaching this favourable recommendation on Keeyask, the NFAT review has concluded that an all-gas alternative would not be acceptable, as it would be significantly less economic and produce greater greenhouse gas emissions than hydro-electric power. The PUB Panel also noted that natural gas would not support Manitoba Hydro's firm sales contract with Minnesota Power, putting those export revenues at risk, along with new transmission to the United States. Building early to take advantage of export opportunities – as was done successfully with Limestone – is a proven strategy for keeping rates low.

The NFAT review has also recommended constructing the new Manitoba - U.S. Transmission Interconnection for a 2020 in-service date. The PUB Panel concluded that this project will add value from an economic and financial perspective by enabling expanded power exports from Manitoba Hydro to U.S. customers. Additionally, the PUB Panel noted that the project will benefit Manitoba Hydro's customers within the Province by strengthening the reliability of our power system, adding greater export and import capability and protection during periods of drought or emergency.

We note that the Obama Administration has cited this international transmission project as an important part of "building a 21st century infrastructure" and that the U.S. Department of Energy has committed to work closely with the lead U.S. proponent, Minnesota Power, and state regulators to move the project through the regulatory approval process. These are positive developments that further underscore the immense opportunity that comes with expanding our access to export markets.

The NFAT review has also made important recommendations on the need to move forward with a new integrated resource planning process, with effective public input, to properly assess future resource options. The energy market is evolving rapidly, and we agree that so too must long-term energy forecasting and planning. Emerging sources of renewable energy are becoming more competitive, demand side management (DSM) programming is being tailored to consumer trends, technological innovation is continuing at a rapid pace, and new U.S. emissions standards are changing historic market dynamics. We accept the PUB Panel's recommendation on the need for a new integrated resource planning process, including proper consideration of DSM, and over the next few months we will work with Manitoba Hydro to prepare an implementation plan for this process. We also agree that this process should be undertaken prior to moving forward with other major capital projects beyond Keeyask and the new Manitoba - U.S. Transmission Interconnection.

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With respect to Conawapa and associated transmission upgrades, Manitoba Hydro has been clear that a decision to proceed is not required at this time. While Manitoba Hydro's contract for a 308 MW power sale to Wisconsin Public Services (WPS) is dependent on building Conawapa, more time is available and required to finalize additional power sale arrangements to strengthen the business case for more power resources.

We note also that following the conclusion of the NFAT hearings, the U.S. Environmental Protection Agency (EPA) released new greenhouse gas emissions standards for the power sector. These standards are widely expected to put greater pressure on utilities in Manitoba Hydro's customer jurisdictions to replace aging coal-fired generating stations with renewable sources of energy. This recent development, in combination with the new Manitoba - U.S. Interconnection, has great potential to open up even larger export market opportunities for clean energy resources, like Conawapa and DSM, as customers look to secure clean, reliable power to diversify their energy portfolios and manage their exposure to environmental issues.

Our Government continues to regard Conawapa, located within the Fox Lake Resource Management Area, as a vitally important component of Manitoba's energy future with the potential to create 10,000 person years of employment and produce far-reaching opportunities for Aboriginal engagement and northern development. However, following from the NFAT review, it is clear that more time is required to secure additional profitable export sales in order to build a stronger business case to justify moving forward with Conawapa and other energy resources beyond Keeyask. We therefore accept the need to freeze expenditures planned for pre-construction work on Conawapa at this time. As additional export sales are confirmed and a stronger business case is developed, a further independent review of Conawapa can be undertaken in the future.

You have advised that Manitoba Hydro remains confident in its ability to secure additional profitable export sales, to justify a stronger case for additional future resource development. We understand that further to recent Memorandums of Understanding (MOUs) negotiations are progressing with both SaskPower and Great River Energy and that new talks are scheduled to begin with long-time customer, Northern States Power, for additional power resources after 2020.

You have also advised us that there are certain activities that are currently underway which relate to Conawapa but which also have broader and enduring value to the corporation, to local communities and to the environment. These include technical environmental studies and analyses required to preserve knowledge gained through extensive fieldwork and Aboriginal traditional knowledge (ATK) studies that help to shape local community development and resource management plans. We agree with you that these limited in-progress activities should be continued, as they are consistent with the Clean Environment Commission's emphasis on the importance of attaining the highest standards of environmental stewardship and continuing to work toward reconciliation with Aboriginal peoples. Carrying on with this limited set of activities will allow Manitoba Hydro to capture the value of many years of work that would be lost if they are halted mid-stream and will protect the corporation from exposure to higher costs in the future if this work has to be re-started from scratch.

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We also urge Manitoba Hydro to continue to review Conawapa construction cost estimates, with the benefit of 'real-time' experience from Keeyask, and make every effort to identify efficiencies as part of ongoing work that will be required for integrated resource planning.

The NFAT review has made a number of significant conclusions respecting Manitoba Hydro's assessment and delivery of DSM programming. Manitoba Hydro has a history of strong leadership in this area and the corporation's new 15-year Power Smart Plan represents a substantially enhanced commitment to DSM programming. Nonetheless, the PUB Panel has expressed concern about current long-term DSM planning, and about the way in which DSM is compared to supply side resources, concluding that a new independent DSM entity should be established. We accept the recommendation that a new DSM entity be established arm's length from Manitoba Hydro, and over the next few months we will investigate different organizational models to strengthen DSM and provide expanded opportunities for all Manitobans to lower their hydro bills. Affordable electricity for Manitoba families and businesses must remain a central component of Manitoba's overall affordability advantage.

In the interim, we are requesting that the Manitoba Hydro-Electric Board oversee a special priority initiative to develop and implement without delay enhancements to DSM programming in areas identified as priorities in the NFAT review, including special outreach to low income families, Aboriginal and northern communities and customers presently excluded from eligibility due to overdrawn accounts. These enhancements should build on recent improvements to Manitoba Hydro's Affordable Energy Program which take a community-based approach to retrofitting homes in low-income communities and on the Aki Energy program, which is lowering bills on First Nations by switching homes from electric heat to geothermal. These models have the additional benefit of creating skills training and job opportunities for local residents – benefits which the NFAT review has suggested should be better accounted for. The Manitoba Government will also consider the Panel's specific recommendation respecting Government revenues from new hydro development, as well as potential alternatives to support vulnerable consumers to reduce their bills.

The NFAT review has also raised the unique needs of large industrial power users. In response we request that Manitoba Hydro advance measures such as curtailable rates and load displacement programs which meet the needs of large power users like manufacturers and resource industries that create jobs and grow our Province's economy.

Also consistent with the PUB Panel's advice we request that the Manitoba Hydro-Electric Board review its current 75/25 debt-to-equity ratio target with the aim of moderating rates for consumers while ensuring strong financial health for the corporation including maintaining sufficient retained earnings. We further urge the corporation to maintain tight cost controls overall to support strong financial performance and low rates for all Manitoba Hydro customers.

...5

Finally, we note that the PUB Panel has highlighted the significant load growth associated with expected crude oil pipeline expansion. Given the magnitude of these demands there may be merit in considering a special rate design for these customers. We would ask that Manitoba Hydro consider this issue and prepare recommendations if appropriate.

In conclusion, we are pleased to be proceeding immediately with construction of Keeyask and a new Manitoba - U.S. Transmission Interconnection grounded in firm power sales to the United States. This development model will support lower hydro rates for Manitoba families and businesses for years to come creating jobs, training, investment and growth opportunities throughout our Province and laying the foundation for a new generation of northern development. DSM will be strengthened to help Manitobans reduce their hydro bills and a new more comprehensive integrated resource planning process will be undertaken to chart Manitoba's energy future. Manitoba Hydro will prioritize the finalization of additional export contracts needed to strengthen the business case for further resource development beyond Keeyask so that Conawapa and other resources can be reviewed again in the future.

Sincerely,

Stan Struthers

Stan Struthers
Minister

TAB 6

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

2017/18 and 2018/19

GENERAL RATE APPLICATION

PUBLIC HEARING

Before Board Panel:

Robert Gabor - Board Chairperson

Marilyn Kapitany - Vice-Chairperson

Larry Ring, QC - Board Member

Shawn McCutcheon - Board Member

Sharon McKay - Board Member

Hugh Grant - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

December 12, 2017

Pages 1450 to 1636

planning -- it was a recommendation of the province of Manitoba as in -- has integrated resource planning been a cornerstone of their energy planning and policy in the province.

I'm not sure that was directed specifically at -- at Manitoba Hydro but I'd have to revisit specifically those recommendations.

MR. ANTOINE HACAULT: That's fine. I think the -- we've got that letter on the record, so we can refer to -- to that on the record.

But in integrated resource planning if we started with a clean slate, as you described initially, am I correct that you might approach DSM as a separate resource and decide whether or not and to what extent you use that as a resource as opposed to a new generating station?

MR. TERRY MILES: So I suppose that that was an option, on going forward, we could -- we could do that. Yes.

MR. ANTOINE HACAULT: Thank you. The next subject which I'd like to have some high-level discussions just to clean up some of the discussions which were occurring as depreciation.

Now depreciation -- and anybody can answer this -- this is a non-cash item. Correct?

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) Transmission costs, including Dorsey, are classified as 100% demand.

(d) Transmission and ancillary services costs are allocated on the basis of the 2 CP.

(e) Generation demand costs are allocated on the basis of the 2 CP.

(f) Energy related costs of generation are allocated on the basis of class annual energy (Non-Coincident Peak).

(g) HVDC costs (other than Dorsey) are functionalized as generation.

(h) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

(i) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(j) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

21.12 Rate Design

21.12.1 General

Although Hydro did not apply for any changes in rate design, the Board and the Intervenors considered the issues of rate design to be of considerable importance in this status update filing. As part of the Board's review as to whether the rates charged remain just and reasonable, the Board not only examined the overall revenue requirement, but also the cost of service methodology, and the rate structure itself.

The Board is disappointed with the inaction of Hydro to comply with the spirit of Order 51/96 with regard to undertaking a study and reporting to the Board by no later than the next GRA to develop a comprehensive rate design policy. More than six years have elapsed since that directive was issued, and Hydro stated at this hearing that it has no intention of preparing such a study in the near future. Such inaction is a disservice to the many Hydro customers, particularly those who might benefit from such a comprehensive rate design policy.

Having reviewed rate design issues as part of this status update, the Board believes that certain rates require adjustment.

21.12.2 Rates

After examining the overall revenue requirement of Hydro, the Board finds that there is no need for an overall rate adjustment for all customer classes. However, the Board is of the view that rates for certain customer classes should be adjusted.

Much time was spent at the hearing reviewing the Cost of Service Study. A revenue to cost ratio of 1.0 indicates that costs allocated to a customer class equal the revenues earned from that customer class. While unity may be the desired goal, Order 51/96 sets a zone of reasonableness target at 0.95 to 1.05 for revenue to cost coverage ratios. The Board is of the view that this zone of reasonableness of 0.95 to 1.05 continues to be an appropriate target for rate setting purposes.

As demonstrated in the table in Section 17.8.5, certain customer classes and subclasses have consistently remained outside of this zone of reasonableness for long periods of time, in some cases more than 10 years. Therefore, the Board is convinced that directional rate adjustments are appropriate now to address these inequities. Accordingly, the Board will order a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in subclasses greater than 30 kV. Such rate decreases are to be effective April 1, 2003. The Board will direct Hydro to file new rate schedules for Board approval reflecting these rate adjustments.

The Board will also eliminate the winter ratchet over the next two years, which will reduce revenues to Hydro by approximately $3 to 4 million. The Board understands that this change will likely bring the GSM class and GSL subclass less than 30 kV closer to unity. Therefore, no further rate adjustment will be ordered for the GSM or GSL less than 30 kV subclass at this time.

The Board is confident that these rate adjustments will not impact the overall financial strength of Hydro, or its ability to achieve its financial targets.

21.12.3 Inverted Rates and Rate Structure

The declining block structure is largely the result of the historical circumstances of electrification throughout the Province and the construction of major generating plants on the Northern rivers. While the Board is not prepared at this time to support an inverted rate structure, the Board accepts that certain concepts of an inverted rate structure for residential customers may have merit for consideration in the future. The Board compliments both Mr. Lazar and Hydro for preparing thoughtful evidence on this matter and raising interesting new approaches. The Board believes that more study is required before an inverted rate structure can be considered for any customer class. The Board will direct Hydro to prepare a study on the merits of an inverted rate structure across all rate classes including transition and implementation issues. As part of this study, Hydro should evaluate the impact of an inverted rate structure on electric heat customers and residential customers with higher than average loads. This study should be filed with the Board by no later than December 31, 2003.

While the issue of inverted rates was largely confined to residential rates, the Board investigated demand and energy charges levied on larger General Service customers as part of the overall rate design. In the Board's opinion, some of Hydro's demand charges are in the mid to high range as compared to other jurisdictions in Canada, while the energy charges are amongst the lowest in Canada.

The Board is of the belief a lower demand charge and higher energy charge may serve as an impetus to further conservation of electricity since the users may become more aware of their consumption and hence, may attempt to minimize usage. Accordingly, the Board will direct Hydro to prepare a study on the impact of decreasing the demand charge and increasing the tail

23.0 It Is Therefore Ordered That:

1. The interim ex parte Orders listed in Appendix E of this Order BE AND ARE HEREBY CONFIRMED AS FINAL.

2. The Curtailable Rates Program as applied for by Hydro BE AND IS HEREBY APPROVED.

3. Hydro file for Board approval a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect:
   (a) A 1% rate decrease for General Service Small customers;
   (b) A 2% rate decrease for General Service Large customers in subclasses greater than 30 kV; and
   (c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

4. Hydro eliminate the Limited Use Billing Demand Rate option on April 1, 2004 and inform all affected customers of the changes to the winter ratchet and the Limited Use Billing Demand Rate option.

5. Hydro file an application with the Board by no later than June 30, 2003, for approval of Hydro's Open Access Transmission Tariff.

6. Hydro file the following information with the Board by no later than December 31, 2003:
   (a) An updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
   (b) A detailed debt management strategy;
   (c) A study to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro;
   (d) A study on the merits of implementing an inverted rate structure for all customer classes;
   (e) A study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;

6.5 Cost of Service Study

As previously indicated, the Board heard persuasive evidence that the cost of service study (COSS) methodology presently employed by MH requires review and amendment, and now provides known distortions in cost allocation.

Therefore, the Board directs MH to file no later than January 30, 2005 three separate 2006 COSS, reflecting the following:

(a) MH's existing methodology;

(b) The implementation of the NERA recommendations;

(c) The allocation of less expensive generation costs all to domestic customers, with higher cost generation being allocated between domestic and export customers on an in-service date basis as suggested by TREE/RCM; and

(d) MH's preferred approach and methodology, including supporting rationale.

In preparing these studies, MH shall allocate a sufficient share of net export revenue to offset the cost of the implementation of residential uniform rates. Net export revenue shall be taken into account over a five year rolling average, given the wide fluctuations experienced to date.

6.6 Demand Side Management

The Board anticipates receiving MH's revised DSM plan by December 31, 2004, and that this plan will include a review of the option of integrating the approach to natural gas and other alternate fuels, and extending DSM to diesel communities.

15.2 Differential Rate Increases

MH did not propose any class differential rate changes in its application other than for ARL, as it was MH's position that the current COSS has not been sufficiently tested to justify relying solely on the RCC results indicated therein. Furthermore, MH noted that the Board had not given MH any indication as to how marginal cost and environmental considerations will be reflected in Rate Design.

15.3 Interveners' Positions

RCM/TREE suggested that only marginal costs be considered in Rate Design, while the Coalition took the position that while the COSS should be the primary basis for rate setting, marginal cost should also be considered.

MIPUG took the position that the COSS has been adequately vetted to allow it to be established as essentially the entire basis for rate setting. MIPUG strongly supports the concept of moving RCCs to unity over five years, and suggested that a five year migration based on a 2.9% annual rates increase would bring about annual rate increases of:

- Residential 3.78%
- GSS-ND 1.92%
- GSS-D 1.26%
- GSM 2.65%
- GSL <30 5.36%
- GSL 30/100 2.04%
- GSL >30 0.93%
- ARL 1.31%

15.4 Board Findings

The Board has accepted MH's proposal for across-the-Board increases for 2008/09 and 2009/10, in order to allow further consideration of marginal cost factors for subsequent GRA's, and, by Order 90/08, directed a 5% across-the-board increase for all customer classes except for Area and Roadway Lighting, which is to receive no increase.

Also, by Order 90/08, the Board has indicated, on a conditional basis, subject to a number of reports to be required of MH, a further 4% across-the-board increase as of April 1, 2009, except for Area and Roadway Lighting which is to receive no increase.

MH seems to be departing from true cost causation principles. The on-going functional usage of transmission by exports is not being considered.

19.8.0 INTERVENER POSITIONS

19.8.1 CAC/MSOS

To date CAC/MSOS has opposed the use of current COSS methodologies in rebalancing or setting differential rate increases for MH domestic customers. More robust marginal cost based analysis is suggested.

19.8.2 MIPUG

In MIPUG's view the current methodologies adequately calculate the class RCCs and should be used to assign lower differential rates to the GSL >100 class.

19.8.3 RCM/TREE

As in the past, RCM/TREE continues to support the use of an MC-based analysis in the cost allocation process and in rate-setting. With respect to low income and other social policy issues, it is RCM/TREE's position that the PUB unquestionably has jurisdiction to impose such an approach.

19.9.0 BOARD FINDINGS

MH has chosen not to seek differential class rate increases other than for Area and Roadway Lighting. MH's principles of rate design and cost allocation should be kept current. That said, the Board's position should not be interpreted to imply any support for the Cost of Service methodology changes employed by MH in PCOSS10 and PCOSS11.

In previous Board Orders, MH has been directed to treat all exports as a defined business venture obligated to share fully in the Utility's embedded costs. The Board

20.6.0 BASIC MONTHLY CHARGE

The Board has denied MH's recently proposed reduction in the Basic Monthly Charge (BMC), citing a lack of appropriate justification. This is a cost-causation issue, because the current BMC does not nearly meet allocated customer costs.

20.7.0 TIME-OF-USE BILLING

MH has not provided any update on the status of time-of-use (TOU) rates. The elimination of the Winter Ratchet may have accomplished some time-of-use objectives. The Board's request for a September 30, 2008 planned implementing strategy report has not been answered. The Board understands that MH has been consulting MIPUG members on this issue. The content and extent of these consultations should be provided to the Board.

MIPUG's industrial customers are the most likely initial targets for TOU given the presence of appropriate metering. However, in light of current export market prices, TOU may actually have negative revenue impacts for MH. This should be considered further.

20.8.0 AREA AND ROADWAY LIGHTING

As in the previous GRA, MH's rate application did not call for ARL rate increases. The Board concurred with this in its approval of the interim and finalized rate increases.

20.9.0 ENERGY INTENSIVE INDUSTRY RATE

MH initially filed and then withdrew a revised proposal for the Energy Intensive Industry Rate (EIIR) which was being considered by MH's Board of Directors in January 2011. Beyond an indication of further consultations with industry there has been no further update on MH's intended actions.

20.12.0 BOARD FINDINGS

The Board notes that MH's responses on the various special rate issues remain outstanding and should receive more timely attention. The Board invites MH to provide all stakeholders (including the Board) with an overall strategy to co-ordinate the changing of rate structures for MH's various customer classes.

The Board requires MH to file preliminary reports (and status updates on):

- Inverted Rates, with a view to creating a significantly higher-priced second energy block, but providing an accommodation to electric heat customers, some of which do not have access to natural gas for heating;
- GSS and GSM Class consolidation with a view to defining the end-product and the specific timeframe for completion;
- Demand/Energy Rate Rebalancing with a view to defining the optimum balance and timeframe to achieve that balance through the allocation of Class Rate increases to the energy component;
- Time-of-Use Rates with a view to applying these in the near future to Top Consumers and industrial customers that already have the necessary metering capability;
- Limited-Use Demand billing with an update of the continued need for this rate in light of the elimination of the Winter Ratchet;
- the Energy Intensive Industry Rate, with justification for either abandoning the rate proposal or providing an alternative on-peak rate scenario as directed in Board Order 112/09; and
- the Service Extension Policy, including a proposal for the Board's review and possible acceptance in accordance with Order 112/09.

this very early stage of the proceeding. As for the adjustment of all rates, and the issues raised by the Interveners respecting the creation of a larger base rate going into 2013/14 arising from a cumulative 4.5% series of increases on 2012/13, all of those matters are capable of variance in accordance with the Board's jurisdiction on final rate approval for MH.

The Board specifically notes that a decision to finalize the following interim rates should be taken after consideration in a full hearing when supporting evidence for the request can be fully tested by the parties:

- 2% interim rate increase granted effective April 1, 2012 in Board Order 32/12

- 1% interim rate increase initially granted in Board Order 18/10 that has been accumulating in a deferral account since the Board issued Order 5/12.

Cost of Service Studies, as an input in the rate structure for MH remains an ongoing matter affecting rate-setting and the Board is mindful of the concerns and issues raised by both MIPUG and GAC that impact rates for the various classes of consumers. Uniform rate increases across all classes could potentially disadvantage certain classes, depending on the other considerations which the Board may take into account in the existing circumstances of the rate request. As directed in Order 98/12, the Board plans to establish a process to consider MH's Cost of Service methodology. The Board is satisfied that there will be options to address costing principles and allocations for the purpose of fixing rates going forward, and does not find that the added complexity is a basis to reject the current interim rate increase across all rate classes.

The Board does not intend this Order to be a signal to MH or any party to the proceeding, or indeed to ratepayers, that it endorses a segmented interim rate process as the desirable method for rate setting for the Utility. Rather, and as submitted by MH, the Board must address an Application that is brought before it within the jurisdiction of the Board and must properly determine if the rate requested is just and reasonable on the information before it, in light of the timing of the larger ongoing GRA process and in addressing the balancing of the factors to meet the public interest for its rate setting mandate for MH.

The Board accepts the principles advanced by GAC, and as previously identified as an objective by MIPUG, that rate reviews and related processes should lead to predictable, stable rates including rate increases where they are found to be reasonable for the benefit of all electricity consumers and for the maintenance of the financial health of the Utility. The Board also recognizes one of the hallmarks of its ongoing responsibilities, as noted by CAC, that the processes employed and final outcomes be as transparent as possible so that consumers can follow the rationale and factors driving rate increases. At this time, the Board finds that the financial predicament of MH is the factor that weighs most heavily in favour of approval of this rate request.

PUB decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with section 36 of the PUB's Rules of Practice and Procedure (Rules). The PUB's Rules may be viewed on the PUB's website at www.pub.gov.mb.ca.

8.0.0 IT IS THEREFORE ORDERED THAT:

1. Manitoba Hydro's request for a 2.5% interim rate increase, effective September 1, 2012, BE AND IS HEREBY APPROVED, on an interim basis for all domestic customer classes;

2. Manitoba Hydro's request for a 6.5% interim rate increase effective September 1, 2012 on the full cost portion of the rate applicable to General Service and Government customers in four remote communities served by Diesel Generation BE AND IS HEREBY APPROVED, on an interim basis.

1.0 Executive Summary

By this Order, the Public Utilities Board of Manitoba (Board) approves rates for Manitoba Hydro for the April 1, 2014 to March 31, 2015 fiscal year and also for the April 1, 2015 to March 31, 2016 fiscal year.

The Board approves a total 3.95% increase in Manitoba Hydro consumers' billed rates effective August 1, 2015. This will increase the monthly bill of an average residential customer without electric space heat (using 1,000 kWh per month) by $3.20 and an average customer with electric space heat (using 2,000 kWh per month) by $6.11.

However, of the 2015/16 rate increase, only the revenues from a 1.8% rate increase will flow to Manitoba Hydro's general revenues to improve its financial position.

The revenues generated from a 2.15% rate increase are to be placed in the previously established deferral account to mitigate rate increases when the Bipole III Transmission Reliability Project (Bipole III), including the Riel Converter Station, comes into service in 2018/19. Because very significant rate increases will be needed at that time, the Board sees a compelling policy reason to gradually increase rates to avoid rate shock for consumers three years from now.

This Order also finalizes the previously approved interim 2.75% rate increase for Manitoba Hydro's 2014/15 fiscal year. Because this increase was previously granted and is already being collected, there will be no additional impact on ratepayers.

Reasons for the Rate Increases

Manitoba Hydro is making very large capital investments to meet its projected energy and capacity requirements and to replace its aging assets. These investments, which will double Manitoba Hydro's assets and associated costs, will be funded mostly by debt and the remaining balance funded by monies generated from its ongoing operations. Including the refinancing of old debt, Manitoba Hydro projects that it will borrow $2.4 billion in 2015/16 and approximately $3 billion annually between 2016/17 to 2018/19.

Manitoba Hydro has advised that its investments will place pressure on its financial strength and will require significantly higher electricity rates to support its increased costs.

The 1.8% portion of the total rate increase will generate additional revenues that will strengthen Manitoba Hydro's finances and support its borrowing plans. The increase is broadly aligned with the anticipated inflation rate.

The funds set aside in the Board-ordered deferral account, including the revenues from the 2.15% portion of the total rate increase, will be used to smooth the significant rate increases that may otherwise be required when the Bipole III Transmission Reliability Project (Bipole III) is completed, mitigating the resulting rate shock. The capital costs of Bipole III have increased by $1.4 billion (or 44%) in the past year, resulting in a total projected capital cost of $4.6 billion. The project is currently expected to increase Manitoba Hydro's annual costs by $384 million in 2020 and will not generate any related offsetting incremental revenues. A rate increase in excess of 20% would be needed to support this annual cost.

Furthermore, Manitoba Hydro has forecasted lower export revenues, largely because of continued lower export prices. Because export revenues are decreasing, domestic rates will need to increase.

Manitoba Hydro announced that successive increases of 3.95% are indicated until 2031. Despite those rate increases, the utility still projects losses from 2019 to 2025 (the total to exceed $980 million) and deterioration in its financial condition.

While the Conawapa Generating Station is no longer part of Manitoba Hydro's Capital Expenditure Forecast, the combination of higher capital expenditures than initially planned, increased investments in energy efficiency measures and declining export revenues means that significant rate increases will be needed for the next decade.

The Board is extremely concerned about the impact of successive and significant rate increases on ratepayers. However, in setting just and reasonable rates, the Board must balance the interests of ratepayers with the financial health of the utility.

Manitoba Hydro has advised that rate increases in excess of inflation are required into the future. The Board will scrutinize all future requested rate increases and approve rates that are justified by the evidence examined. Because financial projections are highly variable, regular applications and reporting by Manitoba Hydro will allow the Board to be better informed and responsive to changing conditions.

The Board previously advised Manitoba Hydro that it would not consider new rates for April 1, 2016 in the Hearing. Manitoba Hydro is studying the financial targets that are embedded in its integrated financial forecasts. The Board will consider various options regarding a process to review rates for April 1, 2016. The Board does not expect to award any further rate increases until a Cost of Service Study (COSS) Application has been filed and the Board has sufficient time to review the COSS Application.

Bill Affordability

The Board recognizes that higher electricity rates will have an impact on all Manitobans but especially lower income Manitobans. In this Order, Manitoba Hydro is directed to file Terms of Reference for a collaborative process led by Manitoba Hydro to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. The goal of the process should be to develop a program for implementation within one year from the Board's approval of the Terms of Reference.

The Board continues to support the implementation of Manitoba Hydro's Affordable Energy Program (AEP) which offers assistance to lower income homeowners who are in need of energy efficient upgrades such as insulation. The Board approves the proposed increased budget to the AEP for 2015 and directs Manitoba Hydro to consider additional measures to increase participation rates and to assist all-electric customers, particularly those living in communities without access to natural gas heating options,

1.0 Executive Summary

By this Order, the Manitoba Public Utilities Board (Board) approves a 3.36% interim increase in Manitoba Hydro consumers' billed rates effective August 1, 2016; Manitoba Hydro had requested an increase of 3.95% effective April 1, 2016.

The monthly bill of an average residential customer without electric space heat (using 1,000 kWh per month) will increase by $2.83 and an average consumer with electric space heat (using 2,000 kWh per month) by $5.41.

The Board will require that all additional revenue generated from this interim rate increase to flow into the previously established Bipole III Deferral Account. This account was established by the Board to mitigate significant rate increases that will be required when the Bipole III Transmission Project (Bipole III), including the Riel Converter Station, comes into service in 2018/19.

Reasons for the Rate Increase

Manitoba Hydro is making very large capital investments to meet growing energy requirements of Manitoba, to replace aging utility assets, and address increased capacity needs on the system. These investments, which will double Manitoba Hydro's assets and associated costs, will be funded mostly by debt and the remaining balance funded by monies generated from ongoing operations.

The Board last approved a rate increase for Manitoba Hydro effective August 1, 2015 following the Board's review of Manitoba Hydro's General Rate Application. Since then, Manitoba Hydro's long-term financial projections have improved significantly. In 2015, Manitoba Hydro was projecting annual rate increases of 3.95% would be required to return Manitoba Hydro to its target debt-to-equity ratio of 75:25 by 2033/34. The Board is satisfied that, based on Manitoba Hydro's latest financial projections, and the implementation of the accounting Directives set out in Board Order 73/15 (following the 2015/16 General Rate Application), Manitoba Hydro's projected annual rate increase of

3.95% can be reduced to 3.36%. Because this is an 'interim' rate increase, the final amount of this increase is subject to the Board's determinations following a General Rate Application that Manitoba Hydro is to file in the fall of 2016. Further, the Board has decided that the rate increase be implemented as of August 1, 2016 to minimize the impact on ratepayers; the earlier increase would result in two significant increases in less than a one year time period.

The Board has concluded that Manitoba Hydro's financial situation for the 2016/17 fiscal year has improved and Manitoba Hydro does not require additional revenues from a rate increase to obtain a positive net income for 2016/17. This is especially the case when Manitoba Hydro's own projections are adjusted to implement the accounting Directives set out in Order 73/15. As such, the Board considers the public interest to be best served if the entirety of the interim rate increase flows into the Bipole III Deferral Account and can serve to reduce the expected rate shock in 2018/19 and subsequent fiscal years when Bipole III and the Keeyask Generating Station come into service.

In light of the significant revenue requirements related to the construction of new generation and transmission assets, replacement of aging infrastructure, and uncertainties associated with export markets, interest rates, domestic loads and foreign exchange rates, the Board considers it important that General Rate Applications are heard on a regular basis, and no more than two fiscal years apart. By this Order, the Board accordingly directs Manitoba Hydro to file a General Rate Application for the 2016/17 and 2017/18 years by no later than December 1, 2016. A December 2016 filing would allow for the adjustment of consumer rates for August 1, 2017. Should Manitoba Hydro wish an earlier date for rate adjustments they would need to file their Application earlier and allow approximately six months for the Board's review of a General Rate Application. The Board is not prepared to consider interim rate applications unless warranted by unforeseen or emergency situations.

The Board shares the Interveners' concerns that interim rate applications ought not be the 'norm' for Manitoba Hydro. Interim rate applications do not offer the same level of public review as General Rate Applications. Manitoba Hydro's internal planning cycles will need to be adjusted, with prior Board and Intervener consultation, if the Utility requests rate adjustments to coincide with April 1 – the start of Manitoba Hydro's fiscal year.

As there are different Intervener representatives and Board Panels involved in electricity regulatory matters as compared to natural gas regulatory matters, the Board does not intend to conduct any joint reviews at this time. As Manitoba Hydro is aware, the Board is considering the efficiency of changes in the regulatory hearing process, (including in the Manitoba Hydro Cost of Service Study Methodology Review Hearing), involving the use of workshops, technical conferences, and concurrent evidence sessions. The assessment of the results of these efficiency initiatives will allow the Board to consider whether combining electricity and natural gas regulatory processes should be further considered.

At the next Manitoba Hydro General Rate Application, the Board will expect all Parties to thoroughly review and test the revised financial information provided by Manitoba Hydro in this interim rate Application. The granting of interim rate increases does not reduce the onus on Manitoba Hydro to demonstrate that any such rate increases are just and reasonable and should be finalized.

The following customer classes are included in Manitoba Hydro's Cost of Service Study. These customer classes are defined in the Glossary appended to this Order:

- Residential
- General Service - Small ("GSS")
- General Service - Medium ("GSM")
- General Service – Large ("GSL") 0-30kV
- General Service - Large 30-100kV
- General Service - Large >100kV
- Area and Roadway Lighting
- Export
- Diesel[2]

One of the outputs of a COSS is the calculation of total costs allocated to each customer class. The COSS output is a tool that can be used in the ratemaking process to assign target revenue for each rate class. This step includes comparisons showing scenarios of target class revenue to the cost of service-based costs allocated to the respective class. The ratio of the target revenues by class to the allocated class costs results in a Revenue to Cost Coverage ratio ("RCC"). A RCC ratio less than unity (1.0) means that the revenue generated by a class is not sufficient to recover all the costs allocated and assigned to that class; conversely a RCC ratio greater than unity (1.0) means that Manitoba Hydro is recovering more revenue from that class than its allocated and assigned costs.

[2] Most of Manitoba Hydro's customers are served by its hydraulic generation assets and high-voltage transmission network. Customers in four northern remote communities (Shamattawa, Brochet, Lac Brochet, and Tadoule Lake) are not connected to Manitoba Hydro's transmission grid and are served by local diesel-fuelled generators. These four communities are referred to as the "Diesel Zone". Manitoba Hydro develops a separate and distinct COSS for its Diesel Zone customers. Manitoba Hydro tracks all Diesel Zone costs separately from other costs, and then directly assigns such costs to the Diesel class in its COSS. The Diesel COSS then determines the costs that are allocated to the different customer classes within the Diesel Zone. The Diesel COSS methodology is not the subject of this Order.

As previously noted, while a COSS appears to be arithmetically exact, it involves a number of decisions that require the application of judgment. Because of this, and to address goals of gradualism in the ratemaking process, many utilities do not set rates such that the RCC ratios are exactly unity. Instead, many utilities and their regulators, including Manitoba Hydro and the Board, recognize a zone of reasonableness within which the utility is to target the RCC ratios of its customer classes. Manitoba Hydro's zone of reasonableness is currently 0.95 to 1.05, meaning that Manitoba Hydro considers it reasonable when a customer class's rates are set to recover between 95% and 105% of the costs allocated to that class in the COSS. RCCs and the zone of reasonableness are rate design issues that are addressed in the context of a GRA.

TAB 7

PROPOSED

RATE SCHEDULES

TO BE

EFFECTIVE

APRIL 1, 2018

Manitoba Hydro

Available in accessible formats upon request

GENERAL SERVICE

(Customer-Owned Transformation)

LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2018-60*

Energy Charge:	@ 4.002 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 9.25 / kVA

Minimum Bill: Demand Charge

LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2018-61*

Energy Charge:	@ 3.720 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 7.92 / kVA

Minimum Bill: Demand Charge

LARGE EXCEEDING 100 KV - *TARIFF NO. 2018-62*

Energy Charge:	@ 3.606 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 7.05 / kVA

Minimum Bill: Demand Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Applicability:

The General Service Large rate is applicable to services where the transformation is provided by the customer and connected directly to the Corporation's distribution, subtransmission or transmission lines.

Customers who, by nature of their business, do not require service during the months of December, January and February may qualify for the General Service Short-Term Power rate.

PROPOSED

RATE SCHEDULES

TO BE

EFFECTIVE

APRIL 1, 2018

Manitoba Hydro

Available in accessible formats upon request

GENERAL SERVICE

(Customer-Owned Transformation)

LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2018-60*

Energy Charge:	@ 4.179 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 9.65 / kVA

Minimum Bill: Demand Charge

LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2018-61*

Energy Charge:	@ 3.884 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 8.27 / kVA

Minimum Bill: Demand Charge

LARGE EXCEEDING 100 KV - *TARIFF NO. 2018-62*

Energy Charge:	@ 3.764 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 7.36 / kVA

Minimum Bill: Demand Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Applicability:

The General Service Large rate is applicable to services where the transformation is provided by the customer and connected directly to the Corporation's distribution, subtransmission or transmission lines.

Customers who, by nature of their business, do not require service during the months of December, January and February may qualify for the General Service Short-Term Power rate.