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Comparison of the Amended Financial Forecast Scenario to the November 15, 2022 Financial Forecast Scenario

Tab 4 Appendix 4.1.1 provides a Comparison of the Amended Financial Forecast Scenario to the November 15, 2022 Financial Forecast Scenario.

Table of Figures

Electric Operating Statement Comparisons

The following three figures demonstrates the operating statement differences for 2022/23, 2023/24 and 2024/25 between Manitoba Hydro's Amended filing and the November 15, 2022 filing.

Figure 1 Electric Operating Statement 2022/23 Comparison

PROJECTED OPERATING STATEMENT
For the Year Ended March 31, 2023
(In Millions of Dollars)

	Amended Financial Forecast Scenario	November 15, 2022 Financial Forecast Scenario	Increase/ (Decrease)
REVENUES			
Domestic Revenue			
at approved rates	1 875	1 875	-
additional	-	-	-
Extraprovincial	1 283	1 283	-
Other	29	29	-
	3 186	3 186	-
EXPENSES			
Operating and Administrative	589	589	-
Net Finance Expense	909	1 023	(115)
Depreciation and Amortization	618	618	-
Water Rentals and Assessments	81	150	(68)
Fuel and Power Purchased	139	139	-
Capital and Other Taxes	160	160	1
Other Expenses	118	118	0
Corporate Allocation	7	8	(1)
	2 621	2 805	(184)
Net Income before Net Movement in Reg. Deferral	565	382	184
Net Movement in Regulatory Deferral	190	190	-
Net Income	755	571	184
Net Income Attributable to:			
Manitoba Hydro	**751**	**568**	**183**
Non-Controlling Interests	4	4	1
	755	571	184
Proposed Percent Increase	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%

Figure 2 Electric Operating Statement 2023/24 Comparison

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
For the Year Ended March 31, 2024
(In Millions of Dollars)

	Amended Financial Forecast Scenario	November 15, 2022 Financial Forecast Scenario	Increase/ (Decrease)
REVENUES			
Domestic Revenue			
at approved rates	1 847	1 847	-
additional	24	41	(18)
Extraprovincial	1 153	1 153	-
Other	29	29	-
	3 052	3 070	(18)
EXPENSES			
Operating and Administrative	657	657	-
Net Finance Expense	900	1 022	(122)
Depreciation and Amortization	632	632	-
Water Rentals and Assessments	83	149	(66)
Fuel and Power Purchased	163	163	-
Capital and Other Taxes	162	161	0
Other Expenses	80	80	-
Corporate Allocation	7	8	(1)
	2 684	2 873	(189)
Net Income before Net Movement in Reg. Deferral	368	197	171
Net Movement in Regulatory Deferral	106	106	-
Net Income	474	303	171
Net Income Attributable to:			
Manitoba Hydro	**469**	**298**	**171**
Non-Controlling Interests	5	4	1
	474	303	171
Proposed Percent Increase	2.00%	3.50%	-1.50%
Cumulative Percent Increase	2.00%	3.50%	-1.50%

Figure 3 Electric Operating Statement 2024/25 Comparison

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
For the Year Ended March 31, 2025
(In Millions of Dollars)

	Amended Financial Forecast Scenario	November 15, 2022 Financial Forecast Scenario	Increase/ (Decrease)
REVENUES			
Domestic Revenue			
at approved rates	1 853	1 853	-
additional	74	131	(57)
Extraprovincial	964	964	-
Other	29	29	-
	2 920	2 976	(57)
EXPENSES			
Operating and Administrative	687	687	-
Net Finance Expense	886	1 012	(126)
Depreciation and Amortization	643	643	-
Water Rentals and Assessments	79	142	(63)
Fuel and Power Purchased	156	156	-
Capital and Other Taxes	163	163	0
Other Expenses	74	74	-
Corporate Allocation	7	8	(1)
	2 695	2 885	(190)
Net Income before Net Movement in Reg. Deferral	224	91	133
Net Movement in Regulatory Deferral	77	77	-
Net Income	301	168	133
Net Income Attributable to:			
Manitoba Hydro	**295**	**162**	**133**
Non-Controlling Interests	6	6	1
	301	168	133
Proposed Percent Increase	2.00%	3.50%	-1.50%
Cumulative Percent Increase	4.04%	7.12%	-3.08%

The following series of figures demonstrates the changes over the 20-year planning horizon between the two forecast scenarios.

Net Finance Expense

Figure 4 below compares net finance expense between the two financial forecast scenarios. Annual net finance expense in the Amended Financial Forecast scenario is on average $120 million lower which results in a cumulative decrease of $2.44 billion (as shown in Figure 5) over the 20-year forecast period. The decrease to net finance expense is primarily due to the reduction of the provincial guarantee fee from 100 to 50 basis points effective April, 1, 2022.

Figure 4 Net Finance Expense

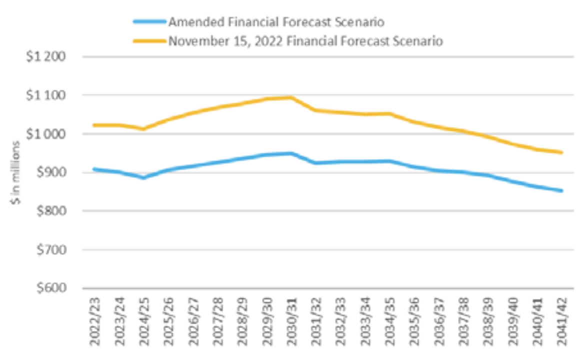
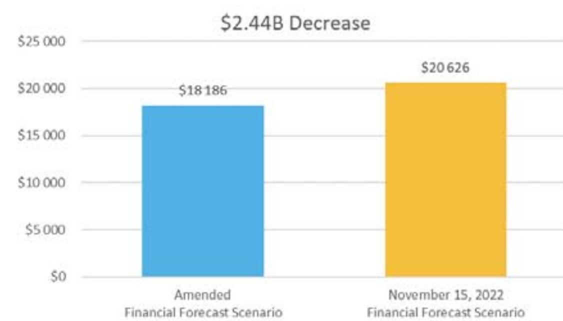


Figure 5 20 Year Cumulative Net Finance Expense



Water Rentals & Assessments

Figure 6 below compares the water rentals and assessments between the two financial forecast scenarios. Annual water rentals in the Amended Financial Forecast Scenario is on average $60 million lower which results in a cumulative decrease of $1.23 billion (as shown in Figure 7) over the 20-year forecast period. The decrease to water rentals is due to the reduction of the water rental rate from $20.32 to $10.16 per horsepower year output effective April 1, 2022.

Figure 6 Water Rentals & Assessments

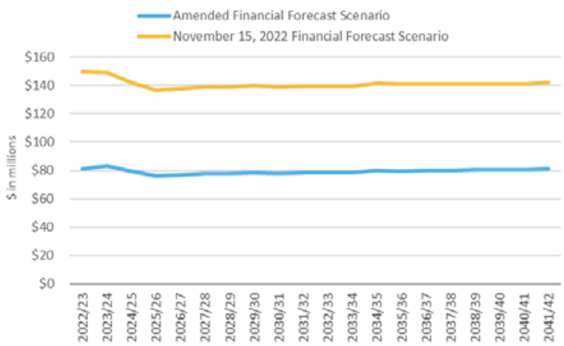
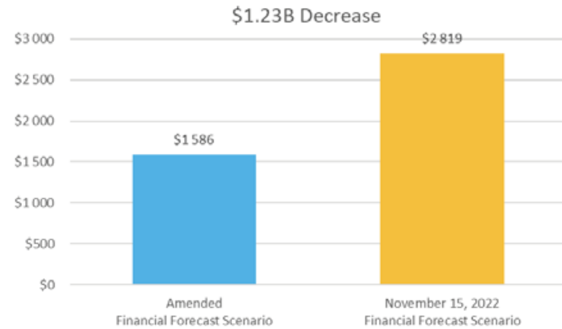


Figure 7 20 Year Cumulative Water Rentals & Assessments



The combined reduction to net finance expense ($2.44 billion) and water rentals ($1.23 billion) total $3.67 over the 20-year forecast period.

Additional Domestic Revenue

Figure 8 below compares the cumulative rate increases projected under each rate path in the two financial forecast scenarios. Both rate paths project cumulative rate increases in the 45% range by the end of the planning horizon. As shown in Figure 9, the 2.0% rate path in the Amended Financial Forecast Scenario is projected to collect $3.80 billion less additional rate revenue from customers over the 20-year forecast period.

Figure 8 Proposed Cumulative Rate Increases

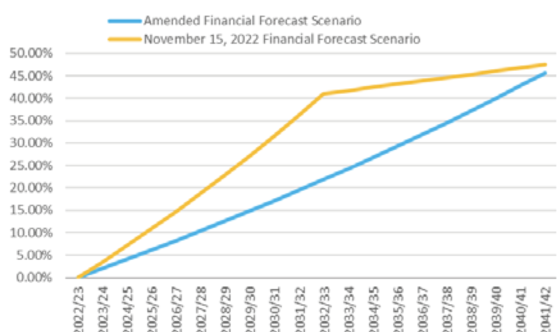
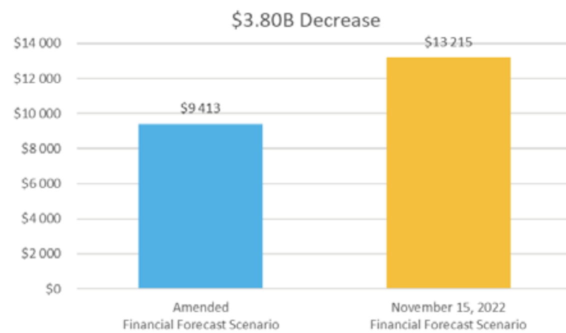


Figure 9 20 Year Cumulative Additional Domestic Revenue



Over the 20-year forecast period, the $3.67 billion combined reduction to net finance expense and water rentals is largely matched by a $3.80 billion reduction to additional rate revenue by adjusting to the 2.0% rate path. Despite the significant changes to these expense and revenue items, the two financial forecast scenarios generate similar financial results over the 20-year planning horizon. Aside from timing differences, the two scenarios are projected to be in very similar financial positions in the last year of the 20-year planning horizon. The following section will illustrate the differences to key financial metrics between the two forecast scenarios.

Net Income

Figure 10 below compares net income between the two financial forecast scenarios. Under the Amended Financial Forecast Scenario, net income is on average $100 million higher over the first seven years (2022/23 to 2028/29), on average $100 million lower over the next ten years (2029/30 to 2038/39) and slightly higher over the last three years. By 2041/42, cumulative net income under the Amended Financial Forecast Scenario is $124 million lower as shown in Figure 11.

Figure 10 Net Income

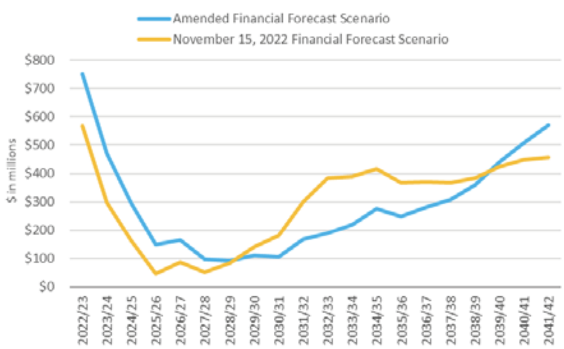
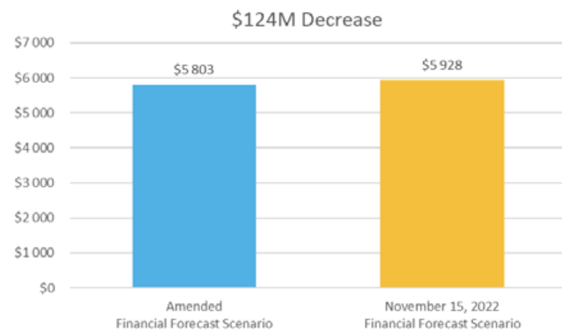


Figure 11 20 Year Cumulative Net Income



Retained Earnings

Figure 12 below compares the retained earnings balance between the two forecast scenarios. Under the Amended Financial Forecast Scenario, the retained earnings balance is as much as $725 million higher in 2028/29, as much as $310 million lower in 2038/39 and $124 million lower in the 20th year of the forecast as shown in Figure 13.

Figure 12 Retained Earnings

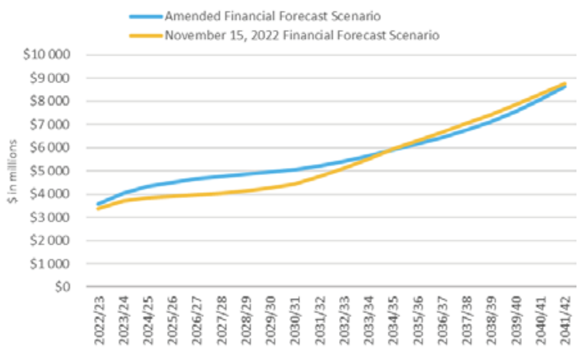
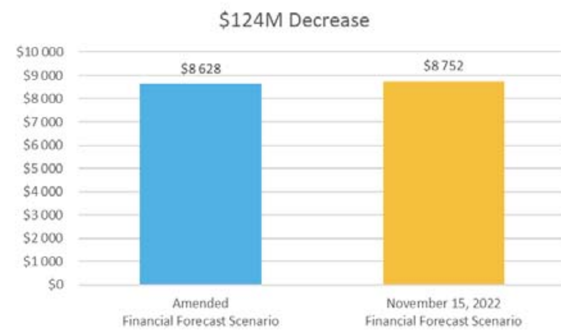


Figure 13 Retained Earnings at 2041/42



Cash Surplus/(Deficit)

Figure 14 below compares the cash surplus/deficit between the two forecast scenarios. The higher earnings over the first seven years (2022/23 to 2028/29) under the Amended Forecast Scenario generates an additional $720 million in cumulative surplus cash over the same timeframe. Over the next ten years (2029/30 to 2038/39), the November 2015 Financial Forecast Scenario generates higher annual earnings which results in higher annual cash surplus. By 2041/42, the cumulative net cash surplus generated under both scenarios are almost identical as show in Figure 15.

Figure 14 Cash Surplus/(Deficit)

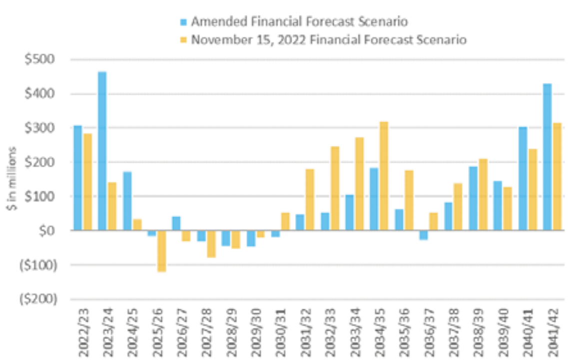


Figure 15 20 Year Net Cash Surplus

Net Debt

Figure 16 below compares the net debt balance between the two forecast scenarios. Under the Amended Financial Forecast Scenario, the higher surplus cash generated over the first seven years (2022/23 to 2028/29) results in lower net debt through 2033/34. By 2041/42, the net debt balances are almost identical as show in Figure 17.

Figure 16 Net Debt

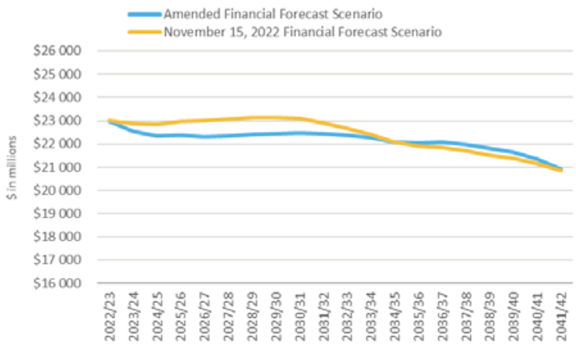


Figure 17 Net Debt at 2041/42

Debt Ratio

1 Figure 18 below compares the debt ratio between the two forecast scenarios. Under the
2 Amended Forecast Scenario, the higher earnings and surplus cash over the first seven years
3 (2022/23 to 2028/29) results in an improved debt ratio with the 80% debt ratio target being
4 achieved in 2028/29. Figure 19 below compares the achievement dates of the 80% and 70%
5 debt ratio targets for both forecast scenarios.

Figure 18 Debt Ratio

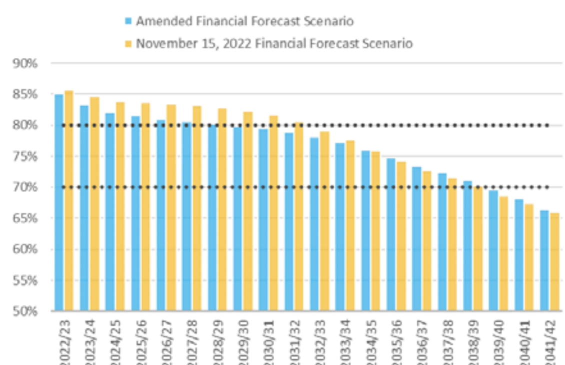


Figure 19 Achievement of Debt Ratio Targets

	Amended Financial Forecast Scenario	November 15, 2022 Financial Forecast Scenario
80% Target	2028/29	2032/33
70% Target	2039/40	2038/39

DOC 02

REFERENCE:

Tab 4, Section 4.4.2, pg. 14 and MFR 65, pg. 1.

PREAMBLE TO IR (IF ANY):

MH indicates that the economic and financial indicators used in the Financial Forecast Scenario provided in Appendix 4.1, are from the Spring of 2022.

MH indicates that it updates interest rates on a quarterly basis (MFR 65, Page 1).

QUESTION:

Please provide an analysis of the differences between the Spring 2022 interest rates used in the Financial Forecast Scenario and the MH Fall 2022 update of interest rates.

RESPONSE:

Table 1 compares Manitoba Hydro's consensus forecasts between the Summer 2022 interest rates used in the Amended Financial Forecast Scenario, with the most up-to-date Winter 2022 update of interest rates that reflects a consensus view as at the end of December 31, 2022. Interest rate changes from Summer 2022 to Winter 2022 range from -15 basis points to +105 basis points for short-term Canadian interest rates and from -10 basis points to 30 basis points for long-term Canadian interest rates.

Table 1 Comparison of Forecast Interest Rates*

	MH Short-Term Cdn Interest Rate			MH Long-Term Cdn 10 Yr+ Interest Rate**		
	Winter 2022	Summer 2022	Increase/ (Decrease)	Winter 2022	Summer 2022	Increase/ (Decrease)
2022/23	3.25	2.45	0.80	4.10	4.20	(0.10)
2023/24	4.00	2.95	1.05	4.00	4.05	(0.05)
2024/25	2.95	2.50	0.45	3.90	3.85	0.05
2025/26	2.30	2.15	0.15	3.90	3.80	0.10
2026/27	2.30	2.10	0.20	4.00	3.85	0.15
2027/28	2.30	2.15	0.15	4.05	3.95	0.10
& on	2.35	2.50	(0.15)	4.25	3.95	0.30

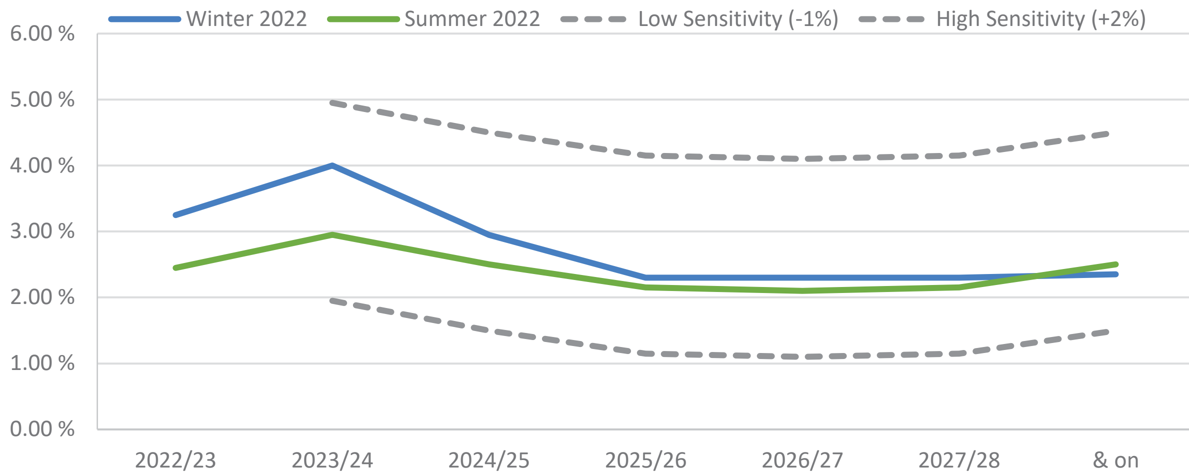
*Not including the Provincial Guarantee Fee
**2022/23 represents average of the remaining quarters

Figures 1 and 2 below provide a comparison between the Summer 2022 and Winter 2022 consensus interest rate forecast and include the interest rate sensitivity ranges as described in Section 4.4.3 of Tab 4:

- MH Short-Term Cdn Interest Rate: a decrease of 1% (low) and increase of 2% (high) from the Summer 2022 consensus interest rate forecast, and
- MH Long-Term Cdn 10+ Year Interest Rate: a decrease of 1% (low) and increase of 1% (high) from the Summer 2022 consensus interest rate forecast.

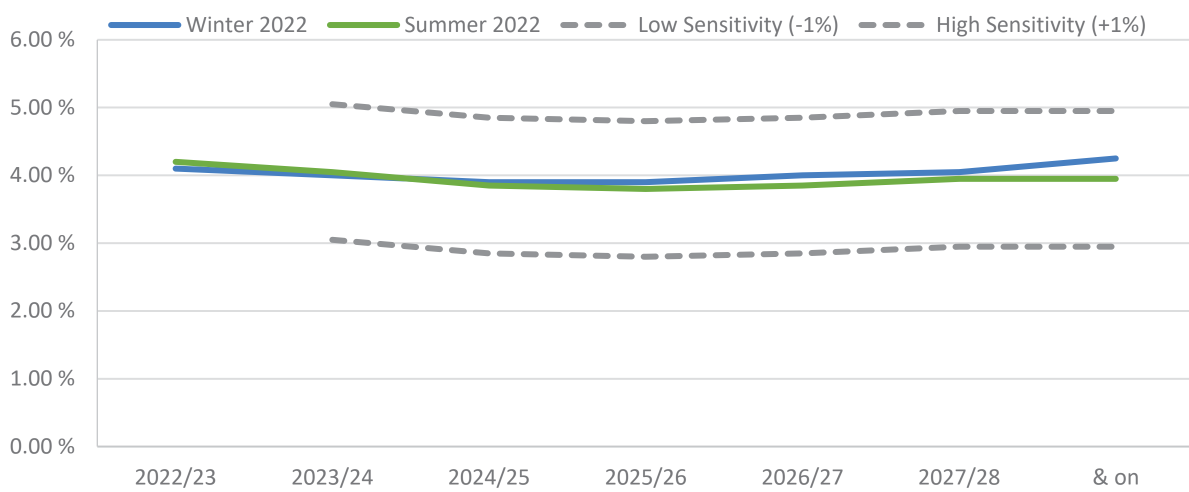
Figures 1 and 2 below demonstrate that the Winter 2022 consensus interest rate forecast is within the bands established in the sensitivity analysis found in Appendix 4.4 (Amended).

Figure 1 MH Short-Term Cdn Interest Rate



Rates do not include the PGF

Figure 2 MH Long-Term Cdn 10+ Year Interest Rate



Rates do not include the PGF

The forecast of interest rates and exchange rates from Winter 2022 are presented in both calendar year (Table 2) and fiscal year (Table 3) format and reflect the consensus benchmark rates as at the end of December 2022. The benchmark interest rates and exchange rates shown in Table 2 represent a 4-quarter average for the calendar year.

Table 2 Canada/US Financial Indicators – Calendar Year

WINTER 2022									
	CANADA					UNITED STATES			
Year	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 5 Yr Rate %	Cdn LT Bond 10 Yr Rate %	Cdn LT Bond 30 Yr Rate %	Cdn LT Bond 10 Yr+ Rate %	US 90 Day T-Bill Rate %	US LT Bond 5 Yr Rate %	US LT Bond 10 Yr Rate %	Cdn$/US$
2016	0.50	0.75	1.26	1.92	1.59	0.32	1.34	1.84	1.33
2017	0.70	1.39	1.79	2.28	2.03	0.95	1.91	2.33	1.30
2018	1.40	2.14	2.26	2.33	2.30	1.97	2.75	2.91	1.30
2019	1.66	1.51	1.55	1.77	1.66	2.10	1.96	2.14	1.33
2020	0.43	0.57	0.72	1.19	0.96	0.37	0.54	0.89	1.34
2021	0.12	1.00	1.40	1.88	1.64	0.04	0.86	1.44	1.25
2022	2.30	2.81	2.80	2.83	2.82	2.08	3.00	2.95	1.30
Forecast									
2023	4.20	3.10	3.05	3.05	3.05	4.65	3.60	3.60	1.35
2024	3.15	2.75	2.90	2.95	2.95	3.55	3.00	3.25	1.30
2025	2.35	2.45	2.85	2.85	2.95	2.60	2.75	3.10	1.29
2026	2.30	2.45	2.85	2.95	3.00	2.45	2.70	3.10	1.29
2027	2.30	2.45	2.90	3.05	3.05	2.45	2.70	3.10	1.29
2028	2.30	2.50	3.05	3.35	3.30	2.45	2.70	3.25	1.28
2029	2.40	2.55	3.20	3.35	3.30	2.55	3.00	3.50	1.28

The benchmark interest rates and exchange rate values shown in Table 3 represent a 4-quarter average for the fiscal year.

Table 3 Canada/US Financial Indicators – Fiscal Year

WINTER 2022									
	CANADA					UNITED STATES			
Year	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 5 Yr Rate %	Cdn LT Bond 10 Yr Rate %	Cdn LT Bond 30 Yr Rate %	Cdn LT Bond 10 Yr+ Rate %	US 90 Day T-Bill Rate %	US LT Bond 5 Yr Rate %	US LT Bond 10 Yr Rate %	Cdn$/US$
2016/17	0.51	0.87	1.39	2.02	1.70	0.40	1.48	1.97	1.31
2017/18	0.87	1.62	1.91	2.26	2.09	1.19	2.06	2.41	1.28
2018/19	1.53	2.06	2.16	2.27	2.21	2.19	2.73	2.88	1.31
2019/20	1.56	1.36	1.39	1.60	1.49	1.78	1.63	1.83	1.33
2020/21	0.14	0.47	0.75	1.28	1.01	0.10	0.40	0.88	1.32
2021/22	0.21	1.31	1.62	2.00	1.81	0.11	1.16	1.60	1.25
Forecast									
2022/23	3.25	3.15	3.05	3.05	3.05	3.15	3.50	3.40	1.32
2023/24	4.00	3.00	3.00	3.00	3.00	4.50	3.45	3.50	1.34
2024/25	2.95	2.65	2.85	2.95	2.95	3.30	2.90	3.20	1.30
2025/26	2.30	2.45	2.85	2.90	3.00	2.55	2.70	3.10	1.29
2026/27	2.30	2.45	2.85	3.00	3.05	2.45	2.70	3.10	1.29
2027/28	2.30	2.45	2.95	3.10	3.10	2.45	2.70	3.10	1.29
2028/29 & on	2.35	2.50	3.05	3.35	3.30	2.50	2.75	3.30	1.28

Tables 4 through 6 summarize Manitoba Hydro's forecasted Canadian and US interest rates, as at the end of December 2022 on a fiscal year basis. Where applicable, relevant credit spreads, average margin level and the PGF of 0.50% are added to the consensus benchmark rates to arrive at Manitoba Hydro's forecasted borrowing costs.

When calculating Manitoba Hydro's fixed and floating long-term debt interest rates for the 2022/23 forecast (Table 5 and Table 6), quarters that have occurred on an actual basis are excluded from the fiscal year average.

Table 4 Canadian Short-Term Interest Rate: Winter 2022

	CDN SHORT-TERM INTEREST RATE			
	Consensus Benchmark 90 Day Cdn T-Bill Rate % *	Manitoba Spread	Provincial Guarantee Fee	MH Interest Rate %*
2022/23	3.25		0.50	3.75
2023/24	4.00		0.50	4.50
2024/25	2.95		0.50	3.45
2025/26	2.30		0.50	2.80
2026/27	2.30		0.50	2.80
2027/28	2.30		0.50	2.80
2028/29 & on	2.35		0.50	2.85

*Rounded to the nearest 5 basis points.

Table 5: Canadian Long-Term Interest Rate: Winter 2022

	CDN FLOATING DEBT INTEREST RATE						CDN FIXED DEBT INTEREST RATE			
	Consensus Benchmark 90 Day Cdn T-Bill Rate %*	Spread from Cdn T-Bill to Cdn BA Rate	Cdn 90 Day BA Rate %*	Average Margin Level	Provincial Guarantee Fee	MH Interest Rate %*	Consensus Benchmark Long-Term 10 Yr+ Rate %*	Manitoba Spread	Provincial Guarantee Fee	MH Interest Rate %*
2022/23	4.25	0.61	4.85	0.50	0.50	5.85	3.15	0.96	0.50	4.60
2023/24	4.00	0.50	4.50	0.50	0.50	5.50	3.00	0.95	0.50	4.50
2024/25	2.95	0.42	3.35	0.50	0.50	4.35	2.95	0.94	0.50	4.40
2025/26	2.30	0.42	2.70	0.50	0.50	3.70	3.00	0.94	0.50	4.40
2026/27	2.30	0.42	2.70	0.50	0.50	3.70	3.05	0.94	0.50	4.50
2027/28	2.30	0.42	2.70	0.50	0.50	3.70	3.10	0.94	0.50	4.55
2028/29 & on	2.35	0.42	2.75	0.50	0.50	3.75	3.30	0.94	0.50	4.75

*Rounded to the nearest 5 basis points.

** Figures may not add to total due to rounding

Table 6: US Long-Term Interest Rate: Winter 2022

	US FLOATING DEBT INTEREST RATE						US FIXED DEBT INTEREST RATE			
	Consensus Benchmark 90 Day US T-Bill Rate %*	Spread from US T-Bill to 6-Month LIBOR Rate	6 Month LIBOR Rate %*	Average Margin Level	Provincial Guarantee Fee	MH Interest Rate %*	Consensus Benchmark Long-Term 10 Yr Rate %*	Manitoba Spread	Provincial Guarantee Fee	MH Interest Rate %*
2022/23	4.65	0.47	5.10	0.41	0.50	6.00	3.75	0.65	0.50	4.90
2023/24	4.50	0.41	4.90	0.41	0.50	5.80	3.50	0.61	0.50	4.60
2024/25	3.30	0.37	3.70	0.41	0.50	4.60	3.20	0.58	0.50	4.30
2025/26	2.55	0.37	2.90	0.41	0.50	3.80	3.10	0.58	0.50	4.15
2026/27	2.45	0.37	2.80	0.41	0.50	3.75	3.10	0.58	0.50	4.15
2027/28	2.45	0.37	2.80	0.41	0.50	3.70	3.10	0.58	0.50	4.20
2028/29 & on	2.50	0.37	2.85	0.41	0.50	3.75	3.30	0.58	0.50	4.35

*Rounded to the nearest 5 basis points.
** Figures may not add to total due to rounding

Tables 7 through 9 depict the sources used to derive the Canadian and US benchmark interest rate forecast for each quarter of the 2022/23 to 2024/25 periods as shown in Tables 3 through 6.

For forecasters that provided end of period rates, rates are adjusted to a comparable average period basis. For example, end of period rates for Q1 and Q2 are averaged for a Q2 average period forecast.

Table 7: Winter 2022 Rates – Canadian

	Cdn 90 Day T-Bill Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	1.59	3.14	4.06	4.40	4.45	4.45	4.45	3.80	3.80	3.80	3.80	
IHS Markit	1.59	3.14	4.06	4.57	4.49	4.53	4.41	4.01	3.76	3.51	3.18	2.68
The Conference Board of Canada	1.59	3.14	4.06	4.39	4.38	4.36	4.05	3.75	3.20	2.70	2.30	2.21
Stokes Economics	1.59	3.14	4.06	4.00	4.00	4.00	4.00	3.10	3.10	3.10	3.10	2.90
Desjardins	1.59	3.14	4.06	4.10	4.10	4.10	4.10	2.65	2.65	2.65	2.65	2.25
CIBC	1.59	3.14	4.06	4.17	4.05	4.00	3.93	3.70	3.40	3.09	2.76	
National Bank	1.59	3.14	4.06	4.24	4.23	3.98	3.50	3.19	3.08	2.97	2.86	
Royal Bank of Canada	1.59	3.14	4.06	4.19	4.15	4.15	4.03	3.70	3.38	3.13	2.93	
Scotiabank	1.59	3.14	4.06	4.19	4.15	4.13	3.88	3.43	3.05	2.90	2.90	
TD Bank	1.59	3.14	4.06	4.37	4.50	4.32	3.82	3.25	2.82	2.51	2.26	2.10
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.25**				**4.00**				**2.95**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**4.25**				N/A				N/A			

	Cdn LT 10 Yr+ Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	2.94	2.96	3.21	3.19	3.28	3.15	3.03					
IHS Markit	2.94	2.96	3.21	2.88	2.81	2.74	2.69	2.65	2.58	2.51	2.47	2.45
The Conference Board of Canada	2.94	2.96	3.21	3.45	3.45	3.45	3.45	3.45	3.42	3.42	3.38	3.37
Stokes Economics	2.94	2.96	3.21	3.35	3.35	3.35	3.35	3.40	3.40	3.40	3.40	3.70
Desjardins	2.94	2.96	3.21	3.03	2.74	2.68	2.63	2.53	2.43	2.38	2.35	2.35
CIBC	2.94	2.96	3.21	3.35	3.44	3.44	3.34	3.17	2.96	2.79	2.68	
National Bank	2.94	2.96	3.21	3.02	2.73	2.68	2.68	2.72	2.77	2.81	2.85	
Royal Bank of Canada	2.94	2.96	3.21	3.08	2.86	2.83	2.79	2.76	2.74	2.73	2.73	
Scotiabank	2.94	2.96	3.21	3.08	2.98	3.19	3.40	3.51	3.55	3.58	3.60	
TD Bank	2.94	2.96	3.21	3.08	2.86	2.84	2.81	2.79	2.76	2.75	2.75	
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.05**				**3.00**				**2.95**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**3.15**				N/A				N/A			

*When calculating long-term debt interest rates, quarters that have occurred on an actual basis are excluded from the fiscal year average.

Table 8: Winter 2022 Components of Cdn LT 10 Yr+ Rate

	Cdn LT 10 Yr Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	2.95	2.99	3.18	3.20	3.30	3.15	3.05	2.95	2.95	2.95	2.95	
IHS Markit	2.95	2.99	3.18	2.88	2.80	2.72	2.67	2.62	2.56	2.49	2.44	2.42
The Conference Board of Canada	2.95	2.99	3.18	3.35	3.35	3.35	3.35	3.33	3.30	3.23	3.18	3.17
Stokes Economics	2.95	2.99	3.18	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.60
Desjardins	2.95	2.99	3.18	3.03	2.73	2.68	2.63	2.53	2.43	2.38	2.35	2.35
CIBC	2.95	2.99	3.18	3.33	3.38	3.35	3.25	3.10	2.90	2.73	2.58	
National Bank	2.95	2.99	3.18	3.03	2.73	2.68	2.68	2.72	2.76	2.79	2.83	
Royal Bank of Canada	2.95	2.99	3.18	3.08	2.83	2.78	2.73	2.68	2.63	2.60	2.60	
Scotiabank	2.95	2.99	3.18	3.08	2.93	3.13	3.35	3.45	3.48	3.50	3.53	
TD Bank	2.95	2.99	3.18	3.08	2.83	2.78	2.73	2.68	2.63	2.60	2.60	2.60
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.05**				**3.00**				**2.85**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**3.15**				N/A				N/A			

	Cdn LT 30 Yr Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	2.92	2.94	3.24	3.18	3.25	3.15	3.00					
IHS Markit	2.92	2.94	3.24	2.88	2.82	2.75	2.71	2.67	2.61	2.54	2.50	2.47
The Conference Board of Canada												
Stokes Economics	2.92	2.94	3.24	3.40	3.40	3.40	3.40	3.50	3.50	3.50	3.50	3.80
Desjardins	2.92	2.94	3.24	3.04	2.75	2.68	2.63	2.53	2.43	2.38	2.35	2.35
CIBC	2.92	2.94	3.24	3.37	3.50	3.53	3.43	3.24	3.01	2.86	2.79	
National Bank	2.92	2.94	3.24	3.02	2.73	2.68	2.68	2.73	2.78	2.83	2.88	
Royal Bank of Canada	2.92	2.94	3.24	3.09	2.90	2.88	2.85	2.85	2.85	2.85	2.85	
Scotiabank	2.92	2.94	3.24	3.09	3.03	3.25	3.45	3.58	3.63	3.65	3.68	
TD Bank	2.92	2.94	3.24	3.09	2.90	2.90	2.90	2.90	2.90	2.90	2.90	
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.05**				**3.00**				**2.95**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**3.15**				N/A				N/A			

*When calculating long-term debt interest rates, quarters that have occurred on an actual basis are excluded from the fiscal year average.

Table 9: Winter 2022 Rates - US

	US T-Bill Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	1.10	2.75	4.18	4.90	5.05	5.05	5.05	4.35	4.35	4.35	4.35	
IHS Markit	1.10	2.75	4.18	4.60	4.77	4.67	4.60	4.55	4.31	3.83	3.35	3.05
The Conference Board of Canada	1.10	2.75	4.18	4.72	4.88	4.79	4.39	3.84	3.33	2.87	2.59	2.52
Stokes Economics	1.10	2.75	4.18	4.50	4.50	4.50	4.50	3.60	3.60	3.60	3.60	3.10
Desjardins	1.10	2.75	4.18	4.60	4.60	4.60	4.60	2.90	2.90	2.90	2.90	2.35
CIBC	1.10	2.75	4.18	4.69	4.93	4.88	4.83	4.53	3.98	3.60	3.40	
National Bank	1.10	2.75	4.18	4.51	4.58	4.28	3.68	3.27	3.11	2.94	2.78	
Royal Bank of Canada	1.10	2.75	4.18	4.61	4.78	4.63	4.38	4.13	3.88	3.63	3.38	
Scotiabank	1.10	2.75	4.18	4.61	4.80	4.80	4.65	4.25	3.75	3.25	2.88	
TD Bank	1.10	2.75	4.18	4.66	4.90	4.78	4.40	3.90	3.40	2.95	2.63	2.43
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.15**				**4.50**				**3.30**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**4.65**				N/A				N/A			

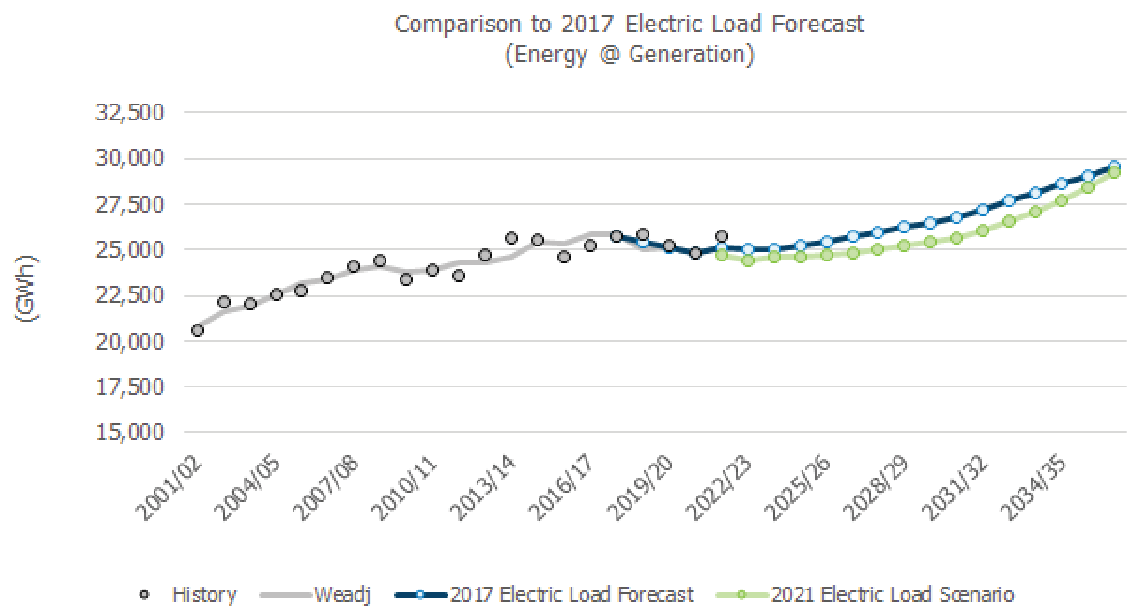
	US LT 10 Yr Rate %											
	2022 Actuals			2023				2024				2025
Forecaster	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	2.93	3.11	3.83	3.85	3.90	3.70	3.55	3.35	3.35	3.35	3.35	
IHS Markit	2.93	3.11	3.83	3.70	3.62	3.54	3.49	3.44	3.38	3.31	3.26	3.24
The Conference Board of Canada												
Stokes Economics	2.93	3.11	3.83	3.90	3.90	3.90	3.90	3.80	3.80	3.80	3.80	3.80
Desjardins	2.93	3.11	3.83	3.72	3.48	3.33	3.18	2.90	2.68	2.65	2.65	2.65
CIBC	2.93	3.11	3.83	3.97	4.03	3.90	3.75	3.63	3.48	3.30	3.10	
National Bank	2.93	3.11	3.83	3.64	3.30	3.13	3.00	2.95	2.95	2.95	2.95	
Royal Bank of Canada	2.93	3.11	3.83	3.82	3.70	3.60	3.50	3.40	3.30	3.23	3.18	
Scotiabank	2.93	3.11	3.83	3.57	3.28	3.35	3.43	3.48	3.53	3.58	3.60	
TD Bank	2.93	3.11	3.83	3.72	3.53	3.45	3.35	3.23	3.08	2.95	2.85	2.78
	2022/23				2023/24				2024/25			
AVERAGE OF FISCAL YEAR QUARTERS	**3.40**				**3.50**				**3.20**			
2022/23 AVERAGE OF REMAINING 1 QUARTER*	**3.75**				N/A				N/A			

*When calculating long-term debt interest rates, quarters that have occurred on an actual basis are excluded from the fiscal year average.

Copies of the publicly available and private sector forecasts are provided as Attachment 1 to this response.

DOC 03

Figure 5.8 Comparison to 2017 Electric Load Forecast Energy @ Generation



Overall, the decrease in the 2021 Electric Load Scenario is due to:

- Declines in production levels in the Top Consumer sector primarily attributable to a mine shutdown in the Primary Metals & Mining sector and the removal of a major project in the Petro / Oil / Natural Gas sector.
- A change in methodology in the calculation of Transmission Losses to better model system operations.
- The lasting impacts of the COVID-19 global pandemic lowering the GDP forecast in the General Service Mass Market sector and negatively impacting production levels in the Top Consumer sector.

These reductions, however, are partially offset by the Residential sector which has seen an increase in energy due an increase in the number of customers who heat with electricity, an increase in the forecast of electric vehicle charging consumption along with an increase in consumption due to the change in the Manitoba workforce, where employers are offering remote work options for employees.

Figure 5.9 shows the Peak Demand comparison between the Electric Load Scenario and the 2017 Electric Load Forecast over the comparable planning horizon of 2021/22 to 2036/37. After including the impacts of DSM capacity savings, the 2021 Electric Load Scenario is higher

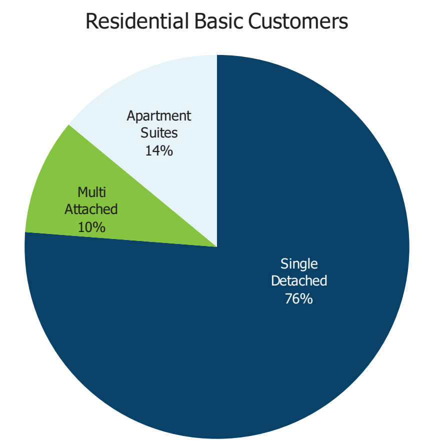
DOC 04

FORECAST DETAILS

Residential Basic

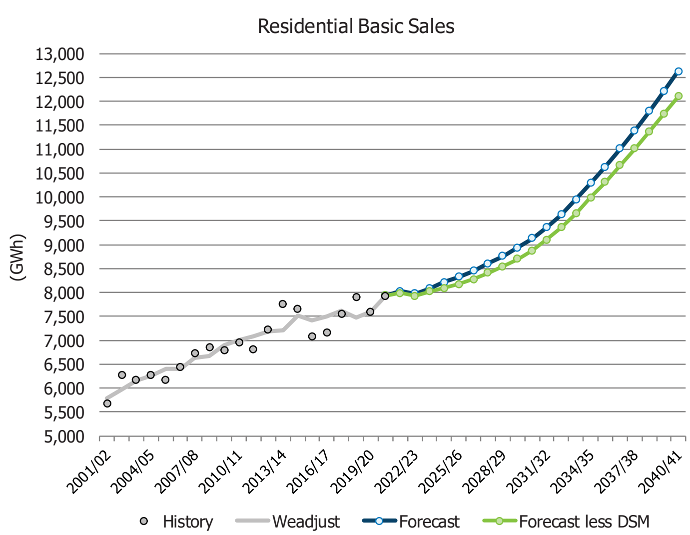
In 2020/21, there were 505,045 Residential Basic customers. Of these customers, 76% were single detached, 10% were multi-attached, and 14% were individually metered apartment suites. Of these customers, 54% in Winnipeg where natural gas is available, 29% are in natural gas available areas outside Winnipeg, and 17% are in areas where natural gas is not available.

Figure 4 – Residential Basic Customers



Residential Basic has grown 113 GWh (1.7%) per year for the past 20 years and 93 GWh per year (1.3%) for the past 10 years reflecting the effect of past Demand Side Management (DSM) initiatives. This sector is forecast to grow 120 GWh (1.4%) per year for the next 10 years and 234 GWh (2.3%) per year for the next 20 years, before future program-based DSM initiatives. Including program-based DSM, the sector is forecast to grow 208 GWh (2.1%) over the next 20 years. The primary driver of Residential Basic growth is population, which is forecast to grow 1.1% per year over the next 20 years.

Figure 5 – Residential Basic Sales



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The following table outlines historical and forecast details including the impacts of program-based Demand Side Management activity:

Table 6 – Residential Sales

Residential Basic Sales (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
2001/02	5,674	113	5,787
2002/03	6,266	(282)	5,984
2003/04	6,170	(18)	6,152
2004/05	6,275	(6)	6,268
2005/06	6,171	234	6,405
2006/07	6,443	(38)	6,404
2007/08	6,736	(99)	6,637
2008/09	6,847	(176)	6,672
2009/10	6,786	112	6,898
2010/11	6,952	57	7,009
2011/12	6,818	275	7,093
2012/13	7,223	(39)	7,184
2013/14	7,767	(564)	7,203
2014/15	7,658	(144)	7,513
2015/16	7,074	338	7,413
2016/17	7,158	336	7,494
2017/18	7,547	85	7,632
2018/19	7,904	(423)	7,482
2019/20	7,598	11	7,609
2020/21	7,919	18	7,937
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2021/22	8,028	(33)	7,994
2022/23	7,984	(61)	7,923
2023/24	8,087	(71)	8,016
2024/25	8,214	(120)	8,094
2025/26	8,326	(155)	8,171
2026/27	8,454	(179)	8,275
2027/28	8,607	(200)	8,407
2028/29	8,763	(216)	8,547
2029/30	8,939	(239)	8,700
2030/31	9,138	(258)	8,879
2031/32	9,360	(258)	9,101
2032/33	9,632	(272)	9,360
2033/34	9,947	(293)	9,654
2034/35	10,283	(298)	9,986
2035/36	10,632	(325)	10,307
2036/37	11,007	(352)	10,655
2037/38	11,395	(385)	11,009
2038/39	11,795	(424)	11,371
2039/40	12,207	(472)	11,735
2040/41	12,624	(522)	12,102

Table 7 – Residential Basic Sales

Residential Basic Sales History and Forecast 2020/21 - 2040/41											
Fiscal Year	Electric Heat Billed (1)			Non Electric Heat Billed (2)			Total Basic			% Elec Space Heat (3)	% Elec Water Heat (4)
	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust	Custs	GWh	kWh/cust		
2020/21	202,141	4,734	23,421	302,903	3,185	10,515	505,045	7,919	15,680	40.0%	50.1%
2021/22	204,605	4,834	23,627	306,448	3,193	10,421	511,053	8,028	15,708	40.0%	50.3%
2022/23	206,652	4,824	23,343	309,273	3,160	10,217	515,925	7,984	15,475	40.1%	50.7%
2023/24	209,014	4,875	23,323	312,525	3,212	10,278	521,539	8,087	15,506	40.1%	51.1%
2024/25	211,456	4,935	23,340	315,961	3,279	10,376	527,416	8,214	15,574	40.1%	51.4%
2025/26	213,961	4,991	23,328	319,396	3,335	10,440	533,357	8,326	15,610	40.1%	51.6%
2026/27	216,647	5,057	23,341	322,696	3,397	10,528	539,342	8,454	15,675	40.2%	51.9%
2027/28	219,424	5,134	23,398	325,955	3,473	10,654	545,379	8,607	15,781	40.2%	52.1%
2028/29	222,235	5,213	23,459	329,240	3,550	10,782	551,475	8,763	15,891	40.3%	52.3%
2029/30	225,119	5,302	23,550	332,514	3,638	10,940	557,633	8,939	16,031	40.4%	52.4%
2030/31	228,095	5,401	23,677	335,762	3,737	11,130	563,857	9,138	16,206	40.5%	52.4%
2031/32	231,159	5,511	23,840	338,966	3,849	11,355	570,124	9,360	16,417	40.5%	52.5%
2032/33	234,267	5,643	24,087	342,135	3,989	11,660	576,402	9,632	16,711	40.6%	52.6%
2033/34	237,398	5,793	24,403	345,248	4,154	12,032	582,646	9,947	17,072	40.7%	52.6%
2034/35	240,519	5,953	24,751	348,282	4,330	12,433	588,801	10,283	17,465	40.8%	52.7%
2035/36	243,628	6,119	25,116	351,226	4,513	12,849	594,854	10,632	17,873	41.0%	52.7%
2036/37	246,717	6,296	25,521	354,124	4,711	13,302	600,840	11,007	18,320	41.1%	52.8%
2037/38	249,790	6,480	25,940	356,998	4,915	13,768	606,788	11,395	18,779	41.2%	52.8%
2038/39	252,870	6,669	26,372	359,870	5,126	14,245	612,740	11,795	19,249	41.3%	52.8%
2039/40	255,992	6,864	26,813	362,760	5,344	14,730	618,752	12,207	19,729	41.4%	52.8%
2040/41	259,137	7,060	27,245	365,666	5,564	15,216	624,803	12,624	20,205	41.5%	52.3%

Notes:

(1) Electric Heat Billed is defined as customers who have electric space heating included with the electric bill.

(2) Non-Electric Heat Billed is defined as customers who do not have electric space heating included with the electric bill.

(3) % Electric Space Heat represents the proportion of Total Res. Basic customers who are Electric Heat Billed.

(4) % Electric Water Heat represents the proportion of Total Res. Basic customers who have Electric Water Heaters.

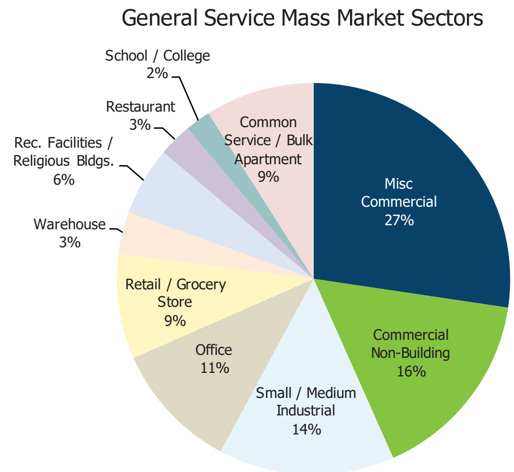
2020/21 GWh and kWh/cust values are not weather adjusted

The average use (kWh/customer) for Electric Heat Billed customers is increasing as individually metered apartment suites are making up a higher proportion of the growth. The average use for Non-Electric Heat Billed customers is increasing mainly due to increased use of electric water heating and miscellaneous end uses in dwellings.

General Service Mass Market

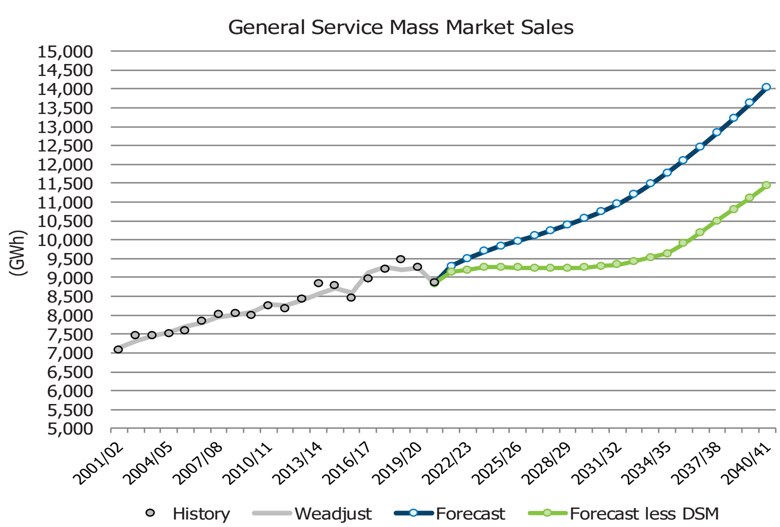
General Service Mass Market includes all commercial and industrial customers, excluding the General Service Top Consumers. There were 69,764 General Service Mass Market customers in 2020/21 with approximately 85% within the commercial sector and 15% within the industrial sector.

Figure 6 – General Service Mass Market Customers



GS Mass Market has grown 69 GWh (0.8%) per year for the past 20 years and 14 GWh per year (0.2%) for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives and includes the seven Top Consumers, totaling 404 GWh in 2015/16, who were moved into the Mass Market sector. The Mass Market Sector is forecast to grow 190 GWh (2.0%) per year for the next 10 years and 260 GWh (2.3%) per year for the next 20 years before program-based DSM initiatives. Including program-based DSM, the sector is forecast to grow 130 GWh (1.3%) over the next 20 years. The primary drivers for growth in the GS Mass Market are the population and the economy. Changes in the number of residential customers and the Manitoba Gross Domestic Product (GDP) are reflected in the GS Mass Market's electricity use.

Figure 7 – General Service Mass Market Sales



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The following table outlines historical and forecast details including the impacts of program-based Demand Side Management activity:

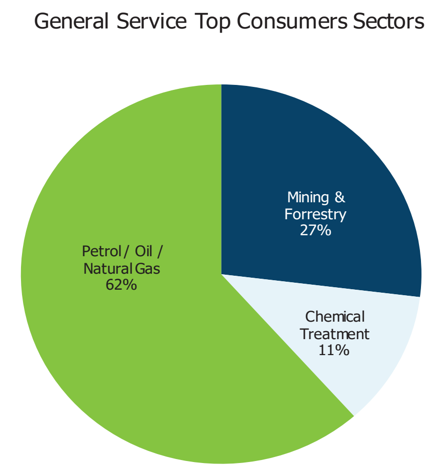
Table 8 – General Service Mass Market

General Service Mass Market (GWh)			
Historical / Weather Adjustment			
Fiscal Year	Sales	Weather Adjust	Adjusted Sales
2001/02	7,084	44	7,128
2002/03	7,467	(144)	7,323
2003/04	7,460	(23)	7,437
2004/05	7,516	34	7,549
2005/06	7,587	108	7,695
2006/07	7,839	(47)	7,792
2007/08	8,006	(55)	7,951
2008/09	8,049	(53)	7,996
2009/10	7,985	85	8,070
2010/11	8,258	37	8,294
2011/12	8,162	96	8,259
2012/13	8,434	(47)	8,387
2013/14	8,839	(273)	8,566
2014/15	8,771	(65)	8,706
2015/16	8,442	157	8,599
2016/17	8,956	173	9,130
2017/18	9,213	71	9,284
2018/19	9,468	(268)	9,200
2019/20	9,256	5	9,260
2020/21	8,851	(9)	8,841
Forecast / Forecast less DSM			
Fiscal Year	Forecast	DSM (Program based)	Forecast less DSM
2021/22	9,298	(152)	9,146
2022/23	9,498	(297)	9,201
2023/24	9,699	(426)	9,273
2024/25	9,832	(557)	9,275
2025/26	9,956	(695)	9,261
2026/27	10,096	(843)	9,253
2027/28	10,241	(997)	9,244
2028/29	10,396	(1,149)	9,247
2029/30	10,561	(1,296)	9,264
2030/31	10,741	(1,447)	9,294
2031/32	10,939	(1,603)	9,335
2032/33	11,198	(1,774)	9,425
2033/34	11,477	(1,950)	9,528
2034/35	11,774	(2,146)	9,628
2035/36	12,104	(2,206)	9,898
2036/37	12,457	(2,266)	10,191
2037/38	12,825	(2,329)	10,496
2038/39	13,207	(2,409)	10,798
2039/40	13,614	(2,509)	11,105
2040/41	14,043	(2,602)	11,440

General Service Top Consumers

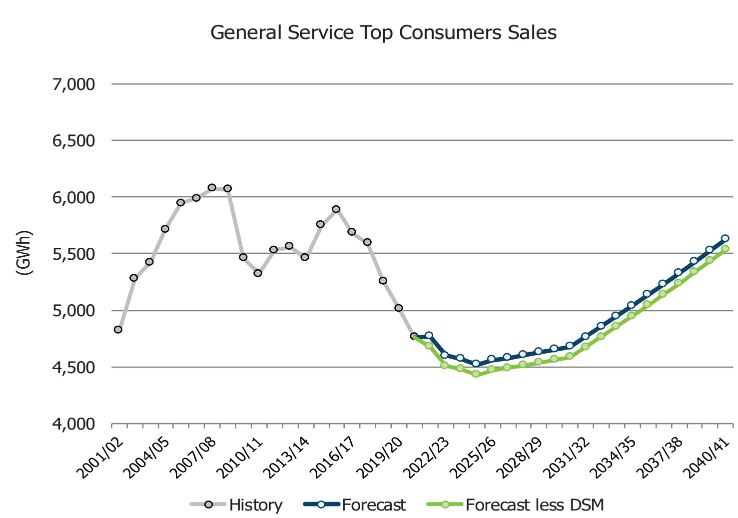
General Service Top Consumers represent the top energy consuming operations in Manitoba accounting for 22% of all General Consumers Sales. GS Top Consumers include 10 distinct companies that count as 26 customers in the Mining & Forestry, Chemical Treatment, Petrol/Oil/Natural Gas sectors.

Figure 8 – General Service Top Consumer Sectors



GS Top Consumers increased 18 GWh (0.4%) per year over the past 20 years and decreased 16 GWh per year (-0.3%) over the past 10 years. The decrease was due to the economic downturn experienced from 2008 to 2011 and the loss of one Top Consumer. The historical growth rates also reflect the shift of the seven smallest Top Consumers to the GS Mass Market Sector, totaling 404 GWh in 2015/16. These were moved because their usage patterns more closely mimic customers within the GS Mass Market sector. The Top Consumers sector is now forecast to decline at an average of 9 GWh (-0.2%) per year for the next 10 years and continue to grow at an average of 43 GWh (0.8%) per year for the next 20 years. Including program-based DSM, the sector is forecast to grow 39 GWh (0.8%) over the next 20 years. Short term reductions are expected in the Petro/Oil/Natural Gas and Chemical Treatment sectors.

Figure 9 – General Service Top Consumers Sales



The following table outlines historical and forecast details including the impacts of program-based Demand Side Management activity:

Table 9 – General Service Top Consumers

General Service Top Consumers (GWh) Historical / Forecast / Fcst. With PLIL / Fcst. Less DSM							
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total	DSM (Program based)	Forecast less DSM
2001/02	4,818	2021/22	4,768	0	4,768	(90)	4,678
2002/03	5,282	2022/23	4,599	0	4,599	(90)	4,509
2003/04	5,423	2023/24	4,570	0	4,570	(90)	4,480
2004/05	5,714	2024/25	4,520	0	4,520	(90)	4,430
2005/06	5,948	2025/26	4,561	0	4,561	(90)	4,471
2006/07	5,989	2026/27	4,561	19	4,580	(90)	4,490
2007/08	6,075	2027/28	4,561	41	4,602	(90)	4,512
2008/09	6,065	2028/29	4,561	66	4,627	(90)	4,537
2009/10	5,461	2029/30	4,561	91	4,652	(90)	4,562
2010/11	5,324	2030/31	4,561	116	4,677	(90)	4,587
2011/12	5,531	2031/32	4,561	205	4,766	(90)	4,676
2012/13	5,560	2032/33	4,561	295	4,856	(90)	4,766
2013/14	5,461	2033/34	4,561	387	4,948	(90)	4,858
2014/15	5,750	2034/35	4,561	479	5,040	(90)	4,950
2015/16	5,886	2035/36	4,561	573	5,134	(90)	5,044
2016/17	5,685	2036/37	4,561	669	5,230	(90)	5,140
2017/18	5,592	2037/38	4,561	766	5,327	(90)	5,237
2018/19	5,258	2038/39	4,561	864	5,425	(90)	5,335
2019/20	5,016	2039/40	4,561	964	5,525	(90)	5,435
2020/21	4,762	2040/41	4,561	1,065	5,626	(90)	5,536

For the short term, General Service Top Consumers are forecast individually. Expected increases and decreases from customer's current and upcoming operating and expansion plans are compiled for the first five years of the forecast but exclude longer term plans that are uncommitted and subject to change.

For the long term, the growth of Top Consumers is forecast together econometrically. The econometric long term Top Consumer forecast is referred to as Potential Large Industrial Loads (PLIL). PLIL is based on the historic growth and/or retraction of the ten companies that comprise the Top Consumers as well as one former Top Consumers customer that closed in 2009. These are large companies that both drive and help define the local, national and international economies. The historical data used for modeling PLIL includes company expansions, production increases and reductions due to planned and unplanned shutdowns, cutbacks and labor disruptions. Therefore, the long term forecast implicitly includes the same expectations.

Historical growth of the Top Consumer sector is modeled using Gross Domestic Product (GDP) and electricity price as independent variables. The historic correlation between GDP, price and Top Consumer growth has been very strong and is expected to continue in the future. Future projections of GDP and price are used to forecast the long-term future increase in Top Consumer growth starting from the sixth year of the forecast.

The sum of the individual company forecasts is expected to decline from 4,762 GWh in 2020/21 to 4,561 GWh in 2025/26. After 2025/26, the individual forecasts for these customers are held constant and longer-term growth is considered to be included in PLIL.

PLIL is added starting in year six of the forecast. The econometric forecast for PLIL is based on an expected annual Manitoba/Canada/U.S. real GDP growth rate of 2.0%, leading to a forecast increase of 0.8% annually. Historically, the real GDP growth rate over the past 20 years was 1.7%, the Top Consumers sector growth averaged 0.4% annually.

The Top Consumers sector is expected to decline 201 GWh in the first five years based on individual customer short term plans, and then grow to 1,065 GWh from years 6 to 20 for PLIL.

Other Customers and Consumption

In addition to Residential Basic customers, General Service Mass Market commercial and industrial customers and General Service Top Consumers, the following represents the remaining group of customers who used 230 GWh or 1.1% of Total Sales in 2020/21:

Residential Diesel

There were 649 Residential Diesel customers that used 10 GWh in 2020/21 averaging 15,374 kWh per year per customer. Customers are only allowed 60-amp services which will not allow for electric space heating. Space heating in the four diesel communities is mainly provided by fuel oil. The number of customers is expected to grow to 857 and usage is expected to increase 1.5% a year to 13 GWh by 2040/41. The assumption is that the communities will continue to be separate from the Integrated System.

Residential Seasonal

There were 19,041 Residential Seasonal customers that used 76 GWh in 2020/21, averaging 4,002 kWh per year per customer. The number of customers is expected to decrease 15,244 customers by 2040/41 due to transfers of higher using seasonal customers into the Residential Basic sector. Seasonal customers are billed only twice a year due to low usage, typically being a seasonal residence or cottage. The usage of Residential Seasonal customers is expected to decrease 1.0% a year to 62 GWh in 2040/41.

Residential Flat Rate Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 2,702 remaining services in 2020/21. The number of services and usage is expected to decrease 5.0% per year throughout the forecast period. Usage was 14 GWh in 2020/21 and that will decrease to 5 GWh by 2040/41.

General Service Diesel

In 2020/21, there were 181 General Service Diesel Full Cost customers using 8 GWh. The General Service Diesel sector is forecast to use 8 GWh by 2040/41.

General Service Seasonal

In 2020/21, there were 981 General Service Seasonal customers using 5 GWh. The General Service Seasonal sector is expected to grow to 7 GWh by 2040/41.

General Service Flat Rate Water Heating

General Service Water Heating is a flat rate unmetered service that has not been available to new customers since November 12, 1969. There were 315 remaining services in 2020/21. The number of services is expected to decrease 3.0% per year throughout the forecast period. Consumption was 5 GWh in 2020/21 and that is forecast to decrease to 3 GWh by 2040/41.

General Service Surplus Energy Program

Participants in the Surplus Energy Program (SEP) consumed 44 GWh in 2020/21 and are expected to increase 48 GWh by 2040/41. This energy is considered to be "interruptible" and thus "non-firm". The energy used by these customers is included in Sales, but it is excluded from the Gross Firm Energy forecast.

Area & Roadway Lighting

The Area and Roadway Lighting sector represents 0.3% of all sales within Manitoba. This sector includes electricity sales for the Sentinel Lighting and Street Lighting rate groups. Sentinel Lighting is an outdoor lighting service where units are available either as rentals to an existing metered service or on an unmetered, flat rate basis. Street Lighting includes all public roadway lighting in Manitoba. In 2006, a readjustment of the rate classes moved some flat rate General Service meters into the Lighting sector and starting in 2016, the street lighting LED conversion program decreased energy consumption. Only Street Lights count as customers.

Due to past Demand Side Management impacts, the Area and Roadway Lighting sector was further reduced to reflect additional street lighting LED conversions. Including the effects of past Demand Side Management (DSM) initiatives, the Area and Roadway Lighting sector is forecast to be 65 GWh by 2040/41.

Diesel Sales

There are four communities served by diesel generation in Manitoba: Brochet, Lac Brochet, Tadoule Lake and Shamattawa. Sales within these communities are included in General Consumers Sales, but are not part of the Integrated System, and are thus not part of Common Bus or Gross Firm Load.

Between 1997 and 1999, eleven communities previously served by diesel generation were connected to the Integrated System resulting in the drop in overall diesel sales. The four sites that were to remain diesel were converted from 15-amp service to 60-amp service between 1991 and 2001 causing the increase in those years.

Diesel customers do not have electric heat, which requires a minimum 200-amp service, as a result, there is no weather effect.

Construction Power

Construction Power represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. Construction Power also includes Station Service until a plant is commissioned. Until 2013, about 48 GWh of heating load at the Gillam, Limestone and Kettle town sites was included in Construction Power. This energy is now included in Distribution Losses.

The Construction Power forecast includes the Keeyask Generating Station with an in-service data slated for late 2021.

Station Service

Station Service is the energy used by power plants to generate power and service their own load. Manitoba energy or peak without Station Service is referred to as "Net", and with Station Service as "Gross".

Station Service energy is forecast to be 125 GWh and Station Service peak is forecast to be 22 MW from 2021/22 to 2040/41.

Station Service for Keeyask and for future non-committed plants is excluded from this forecast.

DOC 05

REFERENCE:

Part I Application, Tab 5.1 2021 Electric Load Scenario, page 56 of 77

PREAMBLE TO IR (IF ANY):

The Application states that, "The number of historical dwellings by type and region were each divided into nine space heating systems: Electric Forced Air Furnace, Electric Baseboard, Electric Ground Source Heat Pump, Electric Boiler, Gas High-Efficiency Furnace, Gas Mid-Efficiency Furnace, Gas Standard-Efficiency Furnace, Gas Boiler, and Other heat that is not billed for gas or electric. Percentages of each heat type in existing dwellings were based on the 2017 Residential Energy Use Survey." (PDF p.56)

In outline the methodology behind the forecast for space heating systems in Existing Dwellings, the Application stated that, "The average age of heating systems in existing dwellings was determined from the 2017 Residential Energy Use Survey. The number of annual replacements was estimated using a Weibull distribution based on the average age of each furnace type. Fuel switching was estimated using survey respondents in older dwellings with newer heating systems. Comparing 2017 Residential Energy Use Survey with survey results in 2014, a movement from electric heating systems to natural gas heating systems was recognized and taken into consideration when forecasting future numbers of space heating systems." (PDF p.58)

The Application also indicates that, "Econometric equations were developed to forecast the number of electric space heating systems in new single detached and multi attached dwellings by region…" (PDF p.56)

Table 7 – Residential Basic Sales (PDF p.22) illustrates the differences in consumption between electric-heat customers and non-electric heat customers (typically served with natural gas). The table illustrates that electric consumption in existing electric heat homes is generally between 2.0 to 2.3 times greater than electric consumption in existing non-electric heat homes. The Table also indicates that Manitoba Hydro projections for the share of electric heat homes in future years will remain largely unchanged from the current 40% (approximate) despite significant indications from federal and provincial governments

across Canada indicating future mandates for electric heating in support of climate change action.

QUESTION:

a) Please explain how the methodology outlined for determining the adoption of electric space and water heating accounts for future adoption of residential and commercial cold-weather air-source heat pumps in both new and existing dwellings and businesses between 2023/24 and 2041/42.
b) Please explain how Manitoba Hydro has addressed federal legislation, regulation, and/or policy and potential future provincial mandates for the electrification of space and water heating in support of climate change action.
c) Please explain the impact that emerging electric heating technologies may have on energy and capacity requirements for electric heating in residential dwelling during the forecast period.
d) Please provide forecast scenarios developed by Manitoba Hydro for the electrification of space and water heating, including the impact that emerging technologies (cold weather air-source heat pumps, dual fuel electric air-source with peaking natural gas, etc.) and expanded energy code requirements for buildings may have for mitigating anticipated electricity use through the forecast period

RATIONALE FOR QUESTION:

About 80% of natural gas usage in Manitoba can be directly attributed to the heating for space, water, and industrial processes. Federal mandates and potential future Provincial energy policies and mandates may result in a significant shift from fossil-based heating fuels to clean electric energy sources. Manitoba Hydro's existing methodology for forecasting future heating requirements appears to be heavily biased toward historic forms of electric heat, which are large based on electric resistance heating methods with inherently low coefficients of performance.

RESPONSE:

a) The current methodology outlined for determining the adoption of electric space and water heating does not account for future adoption of residential and commercial cold-weather air-source heat pumps in both new and existing dwellings and businesses between 2023/24 and 2041/42.

b) Manitoba Hydro considers known government policies within its 2021 Electric Load Scenario. Federal, provincial, and municipal governments have broadly discussed electrifying space heating systems to reduce GHG emissions in buildings, but to date, no specific policies to do so have been drafted.

c) Manitoba Hydro is currently evaluating the economics and impact of various space heating technologies and adoption rates as part of the Integrated Resource Plan.

d) Manitoba Hydro is currently evaluating the economics and impact of various space heating technologies and adoption rates as part of the Integrated Resource Plan.

DOC 06

REFERENCE:

Appendix 5.1v pp. 38 of 77, Appendix 5.6, Tab 9 pp. 18-21 of 28

PREAMBLE TO IR (IF ANY):

Appendix 5.1 (p. 38): "*[Behind the Meter] BTM Solar PV energy produced in Manitoba results in a decrease in electric load consumption with the larger reduction occurring in the summer, when maximum solar production is achieved. In situations where customer's demand is less than what is produced, the energy produced is pushed back to the integrated system and sold to Manitoba Hydro. Manitoba Hydro assumes 25% of the energy generated by Solar PV installations will be sold back to the grid and not reduce domestic energy consumption. Manitoba's current peak demand occurs on a cold winter day, early in the morning or early evening, at times where solar resources are not available and as such, there are no impacts to Gross Total Peak Demand.*"

Appendix 5.6 presents the 2022 Supply/Demand Scenario. This scenario includes existing non-utility generation as base supply power resources contributing to winter peak capacity and dependable energy resources throughout the 2022/23 to 2041/42 planning period.
Tab 9 (p. 20-21): "*Energy produced, in excess to a customer's own needs, is purchased by Manitoba Hydro at the Excess Energy Price. […] The Excess Energy Price at the time of filing is $0.05079/kWh and is updated annually on April 1.*"

Tab 9 (p. 18) "*A total of 34.6 MW AC of solar panels were installed as part of the two-year Solar Energy Pilot program that was launched in April of 2016.*"

Tab 9 (p. 21): "*On August 8 2022, Efficiency Manitoba announced a new Solar Rebate Program. In addition, the federal government also offers rebates for installing solar PV through their Canada Greener Homes Grant.*"

QUESTION:

a) Please quantify the proportions of Behind the Meter (BTM) Solar PV energy that are incorporated in the “non-utility generation supply resources” each year as shown in Appendix 5.6.
b) Please tabulate the expected excess energy that Manitoba Hydro expects to receive from solar PV and other BTM generation each year throughout the electric load scenario.
c) Provide the derivation of the $0.05079/kWh excess energy purchase price. Is this price related to Manitoba Hydro’s marginal value of generation?
d) In a similar format as the response to PUB/MH II-57 from the 2017/18 & 2018/19 GRA, please provide the updated generation and combined marginal values. Please identify which year’s Energy Price Forecast underpins the marginal values.
e) Please explain whether future growth in BTM Solar PV energy sold back to Manitoba Hydro as a result of Efficiency Manitoba’s new Solar Rebate Program will be treated as Behind the Meter Generation or DSM Savings in future Manitoba Hydro electric load forecasts.

RESPONSE:

a) Appendix 5.6, line item “Existing Non-Utility Generation” does not include any Behind the Meter (“BTM”) Solar PV energy. Rather, Appendix 5.6, line item “Existing Non-Utility Generation” represents power purchases from non-utility generators in Manitoba, which include wind generation and solar photovoltaic (“PV”) generation. Energy from these generators is considered “all to grid” (i.e., in front of the meter). The total installed nameplate capacity from all power purchases from Manitoba generators (non-utility generation) is approximately 260 MW. The energy quantities shown in Appendix 5.6, line item “Existing Non-Utility Generation” are aggregated between all non-utility generators in Manitoba, as individual energy output per generator is confidential information.

   All BTM Solar PV energy is included as part of the 2021 Electric Load Forecast Scenario net of DSM.

b) Manitoba Hydro has a projection of new BTM Solar PV embedded in the 2021 Electric Load Forecast Scenario. For all new installations, Manitoba Hydro assumes 25% of the energy generated by BTM Solar PV installations will be sold back to the grid. The following table shows the excess energy that Manitoba Hydro expects to receive from the projection of new BTM Solar PV each year throughout the 2021 Electric Load Forecast scenario.

Fiscal Year	Solar to Grid GWh
2022/23	1
2023/24	1
2024/25	2
2025/26	3
2026/27	4
2027/28	4
2028/29	6
2029/30	7
2030/31	9
2031/32	11
2032/33	13
2033/34	16
2034/35	20
2035/36	24
2036/37	29
2037/38	35
2038/39	42
2039/40	50
2040/41	60

c) The excess energy purchase price is currently calculated on an annual basis to reflect the market value of the energy. The price of $0.05079/kWh was derived from the average Day Ahead and Real Time on-peak price determined at the MHEB Midcontinent Independent Service Operator ("MISO") pricing node for the 2021 calendar year in US dollars. It was then converted to Canadian dollars using the Bank of Canada CAD/USD exchange rate for 2021 calendar year. The price can vary significantly depending on the market value. The table below contains historical excess energy prices over the last 5 years.

Historical Excess Energy Prices

Effective Date	Excess energy price ($/kWh)
2022 April 1	$0.05079
2021 April 1	$0.02403
2020 April 1	$0.02949
2019 April 1	$0.03949
2018 April 1	$0.03253

No, the excess energy price is not directly comparable/related to Manitoba Hydro's marginal value of generation. The excess energy price is an energy only value based on recent market price history. The marginal value of supply includes an energy value plus capacity values for generation, transmission and distribution and is based on future price and cost projections.

d) The updated 30 year levelized marginal and the annual marginal values based on general rate application assumptions are provided below. The 2022 spring energy price forecast was used for this analysis.

30 Year Levelized Marginal Values (Cents/kWh, CAD)		
Dollar Year	2021$	2022$
Generation	4.85	4.94
Transmission	0.29	0.30
Distribution	0.54	0.55
Total	5.69	5.80

5a

Basic Marginal Costs Applicable to Distribution Level Programs
Marginal Costs Given at Distribution
(Constant Year 2022 Canadian Dollars)

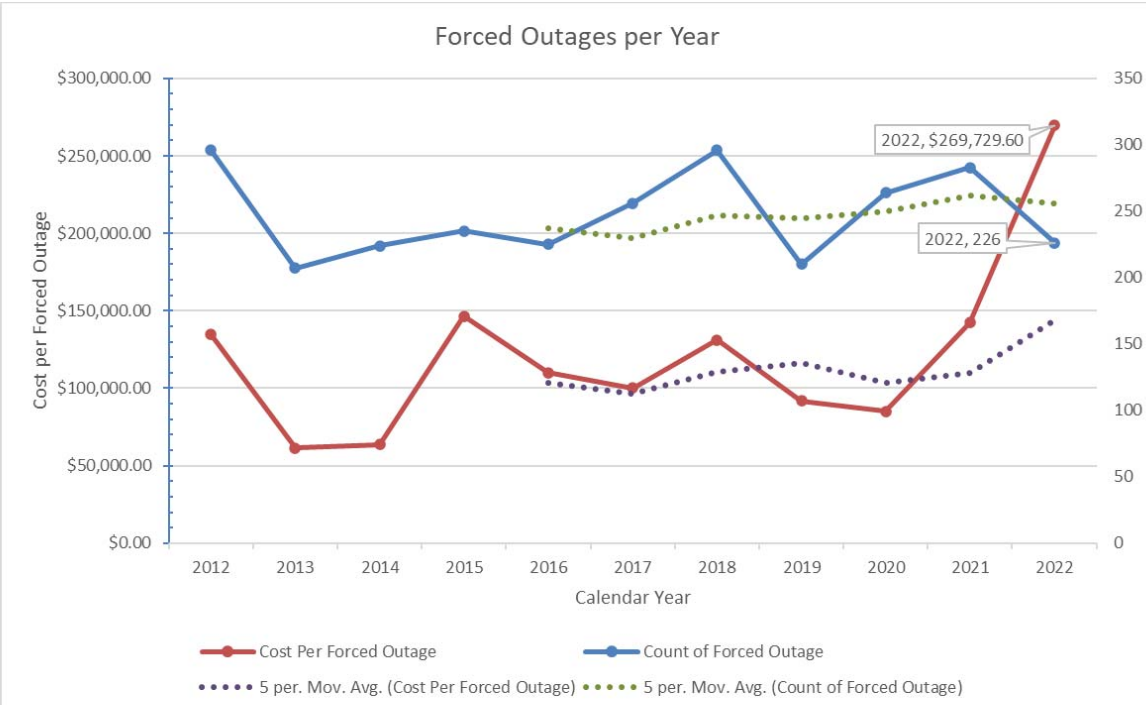
Notes: Marginal costs based on a uniform supply with a 100% capacity factor
Marginal costs referred to distribution (loss factor of 4.82% to translate back to High Voltage Level)
US/Cdn Exchange Rates and Escalation Factors (P911 January 11, 2022)
Updated transmission (2019) & distribution (2019) marginal costs

Fiscal Year	SUMMER		WINTER					ALL-IN		
	Generation Energy	Generation Capacity	Generation Energy	Generation Capacity	Transmission Capacity	Distribution Capacity	Total Capacity	SUMMER	WINTER	ANNUAL
	$/MWh	$/kW/Yr	$/MWh	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/MWh	$/MWh	$/MWh
2024/25	[redacted]				26.33	48.38	[redacted]			
2025/26	[redacted]				26.33	48.38	[redacted]			
2026/27	[redacted]				26.33	48.38	[redacted]			
2027/28	[redacted]				26.33	48.38	[redacted]			
2028/29	[redacted]				26.33	48.38	[redacted]			
2029/30	[redacted]				26.33	48.38	[redacted]			
2030/31	[redacted]				26.33	48.38	[redacted]			
2031/32	[redacted]				26.33	48.38	[redacted]			
2032/33	[redacted]				26.33	48.38	[redacted]			
2033/34	[redacted]				26.33	48.38	[redacted]			
2034/35	[redacted]				26.33	48.38	[redacted]			
2035/36	[redacted]				26.33	48.38	[redacted]			
2036/37	[redacted]				26.33	48.38	[redacted]			
2037/38	[redacted]				26.33	48.38	[redacted]			
2038/39	[redacted]				26.33	48.38	[redacted]			
2039/40	[redacted]				26.33	48.38	[redacted]			
2040/41	[redacted]				26.33	48.38	[redacted]			
2041/42	[redacted]				26.33	48.38	[redacted]			
2042/43	[redacted]				26.33	48.38	[redacted]			
2043/44	[redacted]				26.33	48.38	[redacted]			
2044/45	[redacted]				26.33	48.38	[redacted]			
2045/46	[redacted]				26.33	48.38	[redacted]			
2046/47	[redacted]				26.33	48.38	[redacted]			
2047/48	[redacted]				26.33	48.38	[redacted]			
2048/49	[redacted]				26.33	48.38	[redacted]			
2049/50	[redacted]				26.33	48.38	[redacted]			
2050/51	[redacted]				26.33	48.38	[redacted]			
2051/52	[redacted]				26.33	48.38	[redacted]			
2052/53	[redacted]				26.33	48.38	[redacted]			
2053/54	[redacted]				26.33	48.38	[redacted]			
Levelized Cost at 3.70% Discount Rate	[redacted]				**26.33**	**48.38**	[redacted]			
	[redacted]						Levelized Value (Cents/kWh)			5.8

e) Manitoba Hydro will continue to collaborate with Efficiency Manitoba to ensure any DSM activity related to BTM Generation (Solar and/or by other means) will not be double counted in the modelling within future Electric Load Forecasts.

DOC 07

Figure 7.2 Trend of Forced Outages per Year



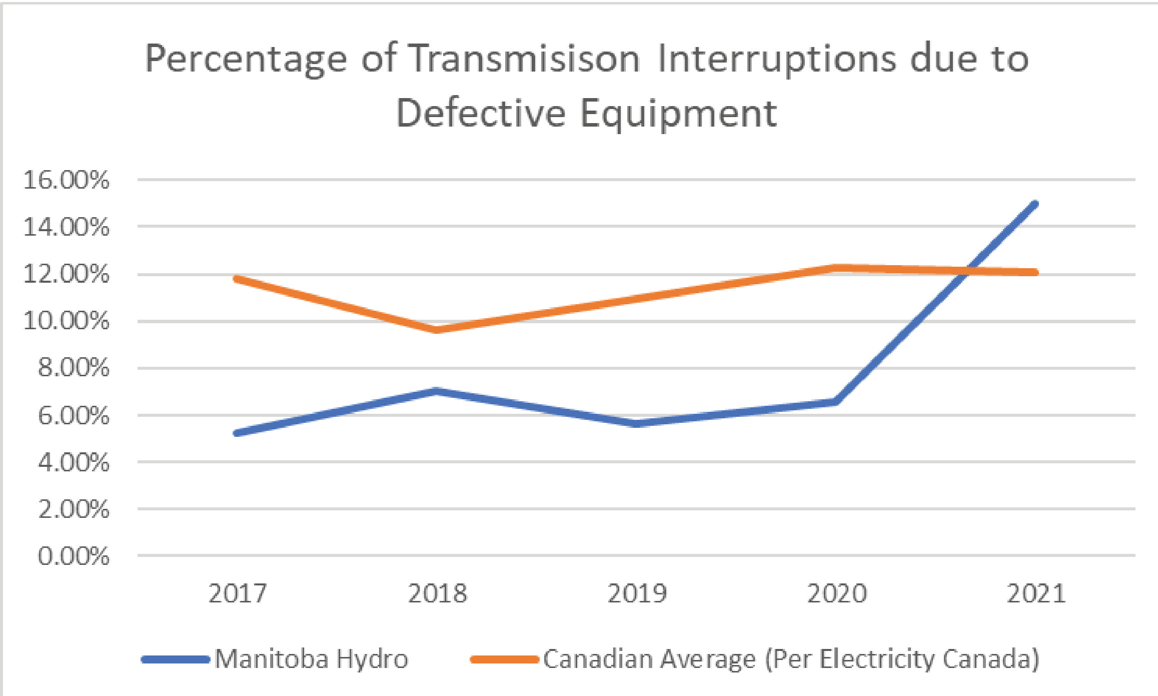
Age demographics of generator assets provide important insight into the effect of aging assets on generation system performance. Since 2011, the generators which are currently "beyond economic life" (27%) have demonstrated a lower availability factor (83%) and a higher weighted forced outage factor (8.4%), compared to new or newly overhauled generators that have a higher availability factor (93%) and much lower forced outage factor (1.5%).

7.1.2 The AC Transmission System is Declining in Performance

Manitoba Hydro is observing a decline in the performance of its AC transmission system. There has been a recent increase in the number of outages caused by defective equipment on the transmission system, of which there are a variety of root causes, including age-related failures.

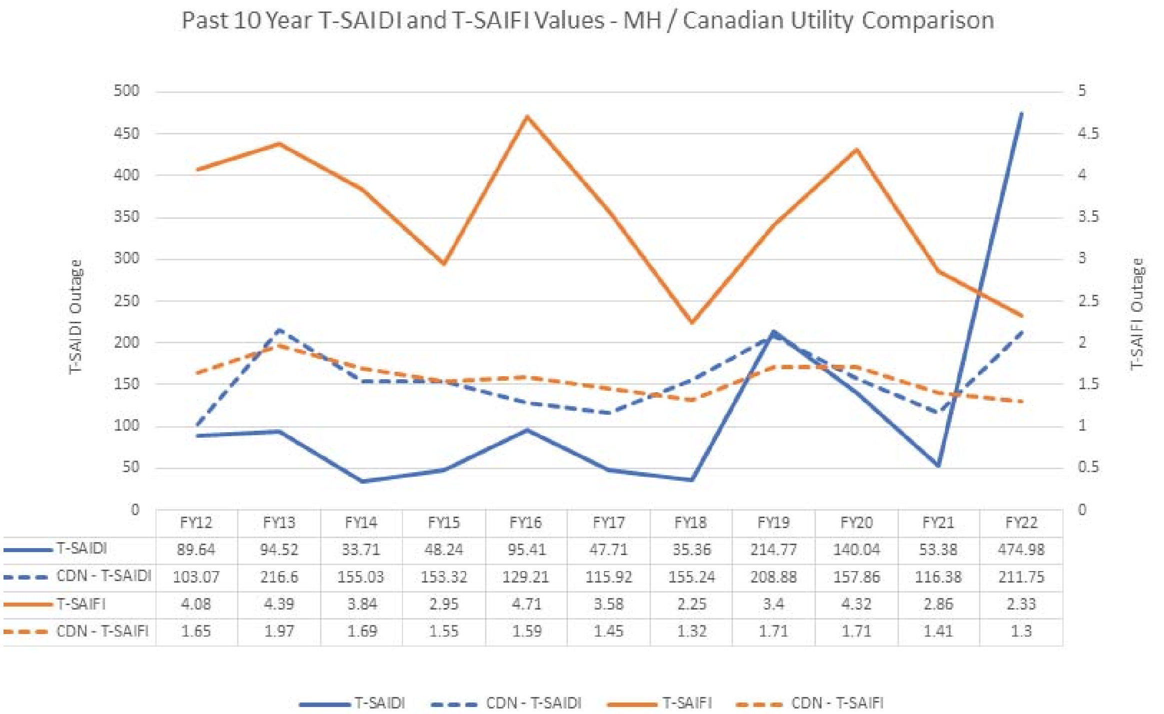
Data collection by Electricity Canada (formerly the Canadian Electricity Association) allows a comparison of transmission system interruptions against other Canadian utilities. Figure 7.3 below shows a sharply increasing trend in interruptions caused by equipment failure for Manitoba Hydro, compared to the average experienced by other Canadian electric utilities.

Figure 7.3 Transmission Interruptions due to Equipment Failure



The Transmission System Average Interruption Duration Index ("T-SAIDI") and Transmission System Average Interruption Frequency Index ("T-SAIFI") are the primary metrics used to assess performance measuring the average duration and frequency, respectively, of interruptions on the transmission system. Interruptions, in the case of these metrics, are measured at the delivery point (where the power is delivered to a directly connected customer or the distribution system). These metrics are benchmarked against Canadian utilities and in both cases, Manitoba Hydro is showing current performance below the Canadian average, as demonstrated in Figure 7.4 below.

Figure 7.4 **10-year History of T-SAIDI and T-SAIFI Values**



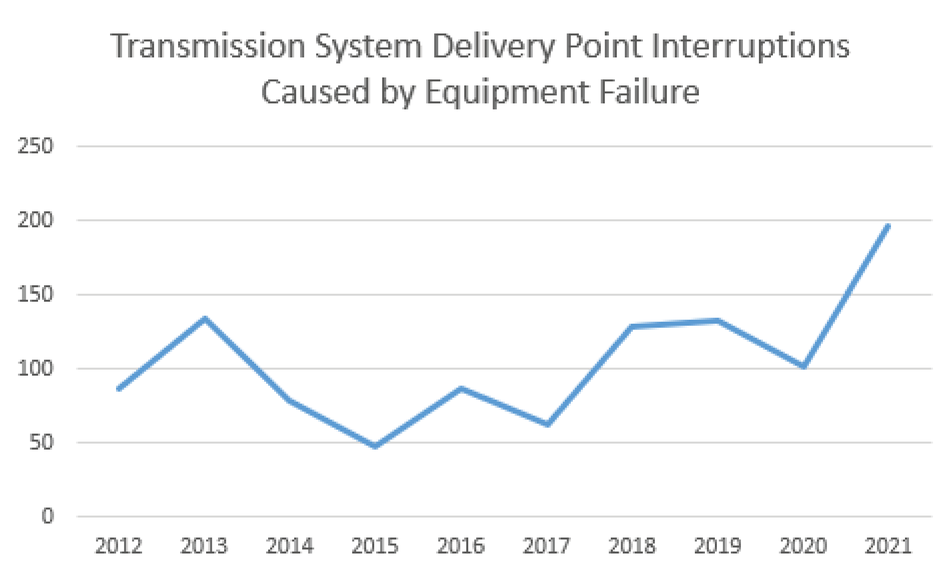
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
T-SAIDI	89.64	94.52	33.71	48.24	95.41	47.71	35.36	214.77	140.04	53.38	474.98
CDN - T-SAIDI	103.07	216.6	155.03	153.32	129.21	115.92	155.24	208.88	157.86	116.38	211.75
T-SAIFI	4.08	4.39	3.84	2.95	4.71	3.58	2.25	3.4	4.32	2.86	2.33
CDN - T-SAIFI	1.65	1.97	1.69	1.55	1.59	1.45	1.32	1.71	1.71	1.41	1.3

Over the last decade, T-SAIDI is showing a negative trend which indicates line outages are taking longer to restore than in previous years. This trend is influenced heavily by the significance of several major weather events that have occurred in recent years. Excluding these major events, such as significant wildfires and the October 2019 storm, results in T-SAIDI values for fiscal years 2019, 2020 and 2022 of 78.68, 42.75, and 100.48, respectively, which is more aligned with historic values. Due to such significant influence from uncontrollable weather events, arriving at conclusions regarding the impacts of asset degradation on this metric is difficult.

Manitoba Hydro's T-SAIFI has shown slight improvement in the last 10 years. As weather is the dominant influence in this metric, equipment failure has been separated to analyze the impact of degrading assets and is shown in Figure 7.5, below.

Despite the improvement in T-SAIFI overall, equipment failure is contributing negatively to the trend. Manitoba Hydro performance is historically unfavourable with respect to the Canadian T-SAIFI average due primarily to its transmission system design. The uniqueness stems from Manitoba Hydro's extensive use of radial 66kV transmission lines to economically serve Manitoba's extensive geographic distribution of small communities. As these radial 66kV lines are tapped off to supply several communities, an outage to one line will cause a disruption to many delivery points.

Figure 7.5 Interruptions Caused by Equipment Failure



7.1.3 The HVDC System is Showing Signs of Performance Decline

The HVDC transmission system has been closely monitored with industry standard metrics and best practices for HVDC systems worldwide have been integrated into Manitoba Hydro's data collection and analysis efforts. This system consists of significant corporate investments in very specialized assets that enable transmission of power from generation stations in the Northern part of the province to the more populous Southern part of the province. As such, outages to the HVDC system can have significant costs to Manitoba Hydro in lost revenue and, in certain circumstances, can put the ability to provide power to all Manitobans in jeopardy.

Trends in recent years have shown HVDC system reliability is declining significantly, as shown in Figure 7.6 below. The performance decline is attributed to the failure of aging assets, as well as the availability of compatible components and appropriate labour resources to perform maintenance and restoration.

Even though the addition of Bipole III as a third, well-performing HVDC transmission line, has lessened the impact of outages to Bipole I and II, any outage event remains significant to system performance.

Figure 7.6 Reliability of HVDC System

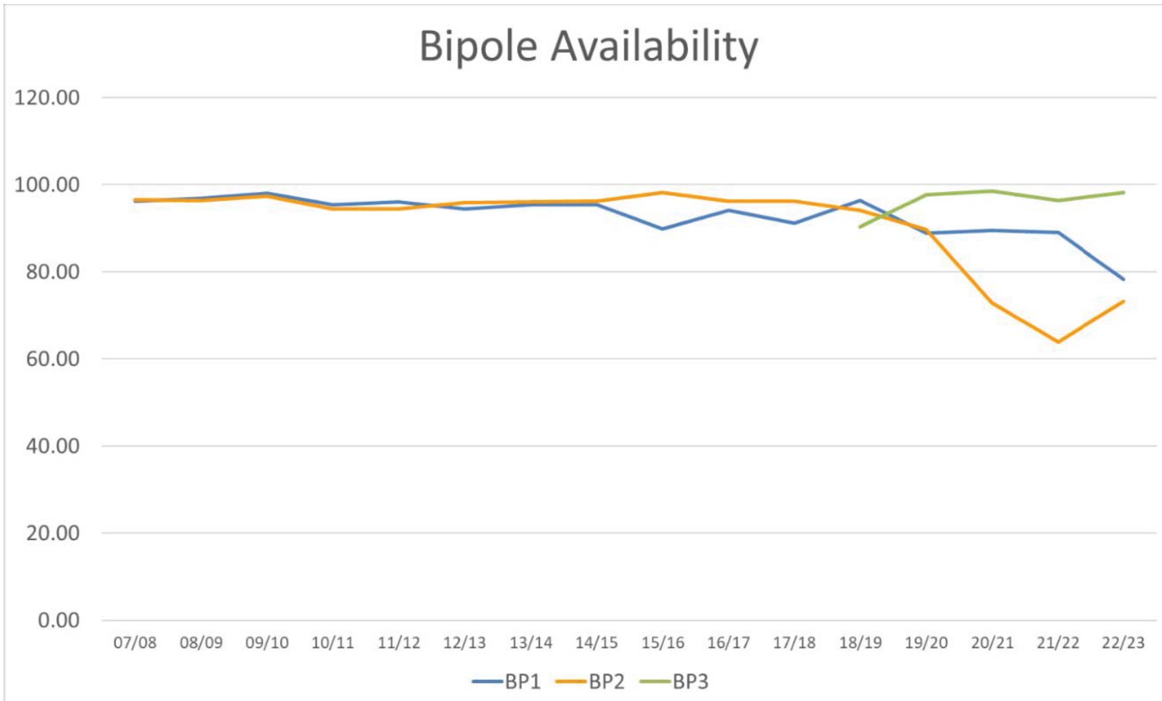
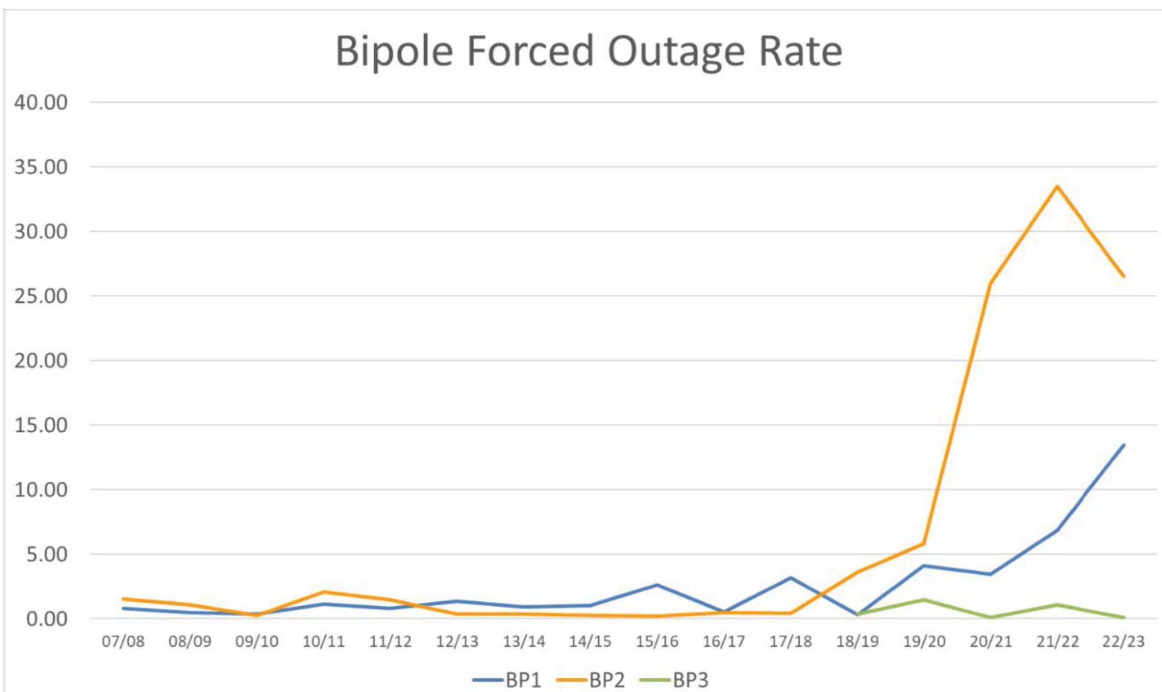


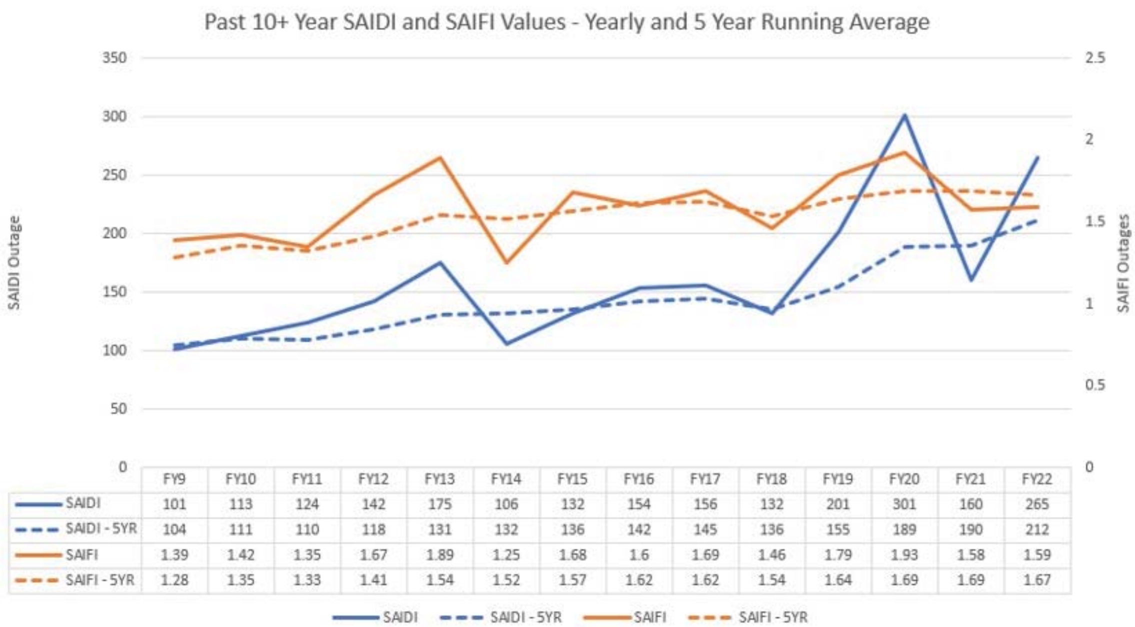
Figure 7.7 Forced Outage Rate



7.1.4 Distribution System is Showing Signs of Performance Decline

Distribution performance utilizes primary metrics of System Average Interruption Frequency Index (“SAIFI”) and System Average Interruption Duration Index (“SAIDI”). These metrics measure the average number and duration, respectively, of outages a customer experiences in a year. As can be seen below, both of these metrics indicate decreasing system performance.

Figure 7.8 **5-Year Historic Average of SAIDI and SAIFI Values**

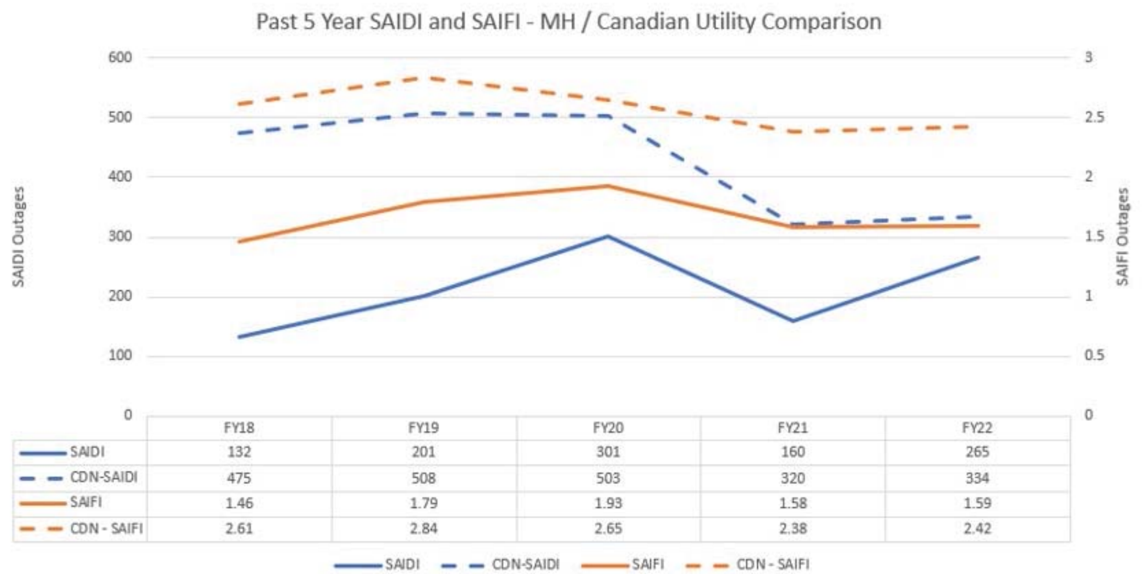


	FY9	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
SAIDI	101	113	124	142	175	106	132	154	156	132	201	301	160	265
SAIDI - 5YR	104	111	110	118	131	132	136	142	145	136	155	189	190	212
SAIFI	1.39	1.42	1.35	1.67	1.89	1.25	1.68	1.6	1.69	1.46	1.79	1.93	1.58	1.59
SAIFI - 5YR	1.28	1.35	1.33	1.41	1.54	1.52	1.57	1.62	1.62	1.54	1.64	1.69	1.69	1.67

Benchmarking of SAIFI and SAIDI values to Canadian utilities is available through Electricity Canada. As can be seen in Figure 7.9 below, Manitoba Hydro’s distribution performance (shown with a solid line) has historically been better than the Canadian average.

The figure also demonstrates that the average Canadian utility showed improved SAIFI and SAIDI values in recent years, while Manitoba Hydro’s metrics have been deteriorating. The primary reason for the decline in Manitoba Hydro’s performance trends is failure of aging assets. Per the 2021 Service Continuity Report (Electricity Canada) Manitoba Hydro distribution outages were caused by equipment failure 35% of the time, while the Canadian average is almost half, at 19%.

Figure 7.9 5-Year History SAIDI and SAIFI Canadian Utility Comparison



	FY18	FY19	FY20	FY21	FY22
SAIDI	132	201	301	160	265
CDN-SAIDI	475	508	503	320	334
SAIFI	1.46	1.79	1.93	1.58	1.59
CDN - SAIFI	2.61	2.84	2.65	2.38	2.42

7.2 We Are Building an Asset Management System

Asset management is the coordination of activities that Manitoba Hydro undertakes to realize value from its assets. Asset management goes beyond repairing failing or failed assets. Asset management is about using the assets to deliver value and achieve business objectives.

Manitoba Hydro is committed to continually improving its asset management system to ensure sustainability of the electrical system and maximize the value provided to customers. As discussed in more detail below, Manitoba Hydro is undertaking significant efforts to create a transparent, standardized, and continually improving system, to continue to improve upon Manitoba Hydro's informed, asset-based decisions.

7.2.1 Status of the Our Asset Management Journey

Delivering on the corporate mission to "help all Manitobans efficiently navigate the evolving energy landscape, leveraging their clean energy advantage, while ensuring safe, clean, reliable energy at the lowest possible cost" requires an extensive portfolio of assets with unique lifecycle requirements and considerations. To better achieve the corporate mission, Manitoba Hydro has committed to adopt formal asset management philosophies and understands the need to mature its asset management practices.

DOC 08

PUB MFR 106
Sustaining and Major Capital

Provide a description of Manitoba Hydro's risk assessment and risk management processes that inform the prioritization for base and major capital expenditures.

As described in Section 5.1.3 of Tab 5 of Manitoba Hydro's Application, decisions to proceed with project execution (such that the project would begin in year 1 of the CEF) are based on a consideration of multiple risk and economic factors reviewed in the context of the specific project relative to other potential investments. Factors include public and employee safety, asset condition and performance, regulatory compliance and asset life cycle costs.

In cases where asset failure is a primary driver of a project's justification, the evaluation of risk considers both the consequence and probability of failure in the specific operating context of the asset, along with the effectiveness of the mitigation alternative in question.

Techniques such as Reliability Centered Maintenance and Failure Modes and Effects Analyses are used to assess risks by tracing failure modes (i.e. how the system might fail) through the assets in the system. Depending on the consequences of failure, risk mitigation may be embedded in the design of the system (e.g. redundancy) or the maintenance plan for the asset (e.g. preventative maintenance). Assets are run to failure where consequences are low and replaced proactively based on condition where consequences are high.

As the asset operating context varies significantly across our generation, transmission and distribution systems, operational risk is evaluated in many different ways. Lost generation risk is used to evaluate the economic risk of generator outage. The risk of unserved load is applied for the transmission system, as described in more detail below. The operational risks of the distribution system include the quality, reliability, security, and available capacity of electrical supply to the customer.

An example of a risk assessment and risk management tool that has been developed by Manitoba Hydro is the System Reliability Risk Model. The System Reliability Risk Model is a sophisticated tool developed in 2015 by Manitoba Hydro specialists with the aim of quantifying the risk associated with a capital project or group of projects in terms of potential impacts to the reliability of the transmission system. The tool models the operation of the transmission system with and without the additional or replacement assets for a given project or group of projects, and compares the expected unserved energy for various potential failures on the related system network. The expected unserved energy represents the weighted average of all possible load shed scenarios based on probability of outage and total electrical loads affected. The model factors in the system configuration, load data, equipment reliability data, and network-specific conditions and averages the results over a five-year window. The difference between the expected unserved energy without the new assets and the expected unserved energy with the new assets is referred to as the delta expected unserved energy (or ΔEUE). The ΔEUE represents the risk to the reliable operation of the system that would be mitigated with the implementation of the project. Projects that are evaluated with the System Reliability Risk Model and have a high ΔEUE score receive funding allocations ahead of those with lower ΔEUEs.

These techniques and others are being built into Manitoba Hydro's Capital Portfolio Management Program to evaluate potential capital investments using the Corporate Value Framework (CVF), as discussed on page 13 in Section 5.1.3 of Tab 5 to assess value in five streams: financial, environmental, reliability, corporate citizenship, and safety & security. Within these streams are 27 measures linked to benefits and risks that impact reliability and performance. A full listing of the measures can be found in MFR 107 and the attached Corporate Value Framework Implementation Document (VFID) provides a description of the measures.

See Section 5.1.3 of Tab 5 for further information and MFR 107 and Copperleaf Value Framework Implementation Document (VFID) for a description of the measures.

DOC 09

PUB MFR 107
Sustaining and Major Capital

Provide a description of how Manitoba Hydro relates capital expenditures to reliability and performance metrics for the generation, transmission, and distribution systems.

Manitoba Hydro uses long-term performance metrics of generating unit availability and forced outage rates on the generation system, as well as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for the transmission and distribution systems. The SAIFI indicator measures the average number of interruptions that customers have experienced, and the SAIDI indicator measures the average outage duration experienced by customers.

These metrics are multi-year moving averages of aggregate system performance that can provide a lagging indication of asset sustainment investment over the long term. However, system performance is also greatly affected by other factors such as adverse weather conditions and to a lesser extent, human operating errors, both of which cannot be mitigated through capital expenditures.

With Manitoba Hydro's Capital Portfolio Management Program, potential capital investments are evaluated using the Corporate Value Framework. The Corporate Value Framework is a systematic framework to understand the value of all investments in an organization. The Corporate Value Framework helps identify the optimal set of investments that deliver the greatest value (or mitigates risk) to the organization, within funding, resource and timing constraints. This tool is used to assess the value of capital investments across all areas of the corporation in support of allocating funds to projects and assets that optimize strategic value or mitigate risk. The Corporate Value Framework assesses values in five streams: financial, environmental, reliability, corporate citizenship, and safety & security. Within these streams, there are 27 measures linked to benefits and risks that impact reliability and performance. The value measures are listed below:

Financial Value Measures:

- Capital Financial Benefits
- O&M Financial Benefits
- O&M Costs
- Financial Risk
- IT Capacity Risk
- Lost Generation Risk
- Export Transfer Capacity Risk
- Productive Workplace Benefit
- Risk of Project Execution (non-Information Technology Services)
- Risk of Project Execution (Information Technology Services)
- Varying Cost or Revenue Benefit
- Generation Revenue Benefit
- Cost of the Investment

Reliability Value Measures:

- Distribution Reliability Benefit
- Gas Distribution Reliability Benefit
- Distribution Outage Recovery Benefit
- Electrical Delivery Capacity Risk
- Gas Delivery Capacity Risk
- Blackstart Delay Risk
- Transmission Reliability Risk
- Import Transfer Capacity Risk

Environmental Value Measures:

- Environmental Benefit
- Environmental Risk

Safety Value Measures:

- Safety Risk
- Security Risk

Corporate Citizenship Value Measures:

- Public Perception Risk
- Compliance Risk
- Customer Service Benefit

Please see section 5.1.3 of Tab 5 of this Application for further information on the Asset Investment Process Improvements and the attached Manitoba Hydro Value Framework Implementation Document (VFID), which provides a more detailed description of the Corporate Value Framework and associated values streams and measures.

Nov 10, 2016 v1.20s

Manitoba Hydro
Value Framework Implementation Document (VFID)

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Table of Contents

Statement of Confidentiality

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Document Control Sheet

Version	Date	Description	Originator
1.0	Oct 25, 2015	Initial Draft	Vlad Serdiuk
1.1	Oct 26, 2015	Content Review	Stan Coleman Vlad Serdiuk
1.2	Oct 28, 2015	Update to Environmental, Compliance, IT Capacity and Public Perception risk consequences	Vlad Serdiuk
1.3	Nov 02, 2015	Update to financial parameters (rates) and CMI cost based on the customer distribution	Vlad Serdiuk
1.4	Nov 04, 2015	Added section 5.3.15 Investment Impact. Updated Risk Matrix with new Consequence levels and descriptions for Compliance and IT Capacity risk types.	Vlad Serdiuk
1.5	Nov 09, 2015	Added Customer Service benefit, Productive Workplace benefit, and Risk of Project Execution (both ITS and non-ITS)	Vlad Serdiuk
1.6	Nov 09, 2015	Updated Gas CMI Cost, Import and Export Transfer Capacity, and added Blackstart Delay Risk	Stan Coleman
1.7	Nov 11, 2015	Added Escalating Cost or Revenue benefit	Vlad Serdiuk
1.8	Nov 18, 2015	Calibrated Risk of Project Execution (ITS) to align with Estimate Class levels	Vlad Serdiuk
1.9	Nov 19, 2015	Changed the wording for Electrical Delivery Capacity Risk to include the power quality statement	Vlad Serdiuk
1.10	Nov 26, 2015	Expanded the description for Lost Generation Risk. Enhanced Table 4 - Value Function Summary – indicated positive and negative value contributors	Vlad Serdiuk
1.11	Nov 30, 2015	Updated Risk of Project Execution (non-ITS). Changed term Cost of Energy to Cost of Export Energy	Vlad Serdiuk
1.12	Dec 08, 2015	Updated Consequence descriptions to include compliance in Safety and Environmental risks. Moved Lost Generation risk to Financial category.	Vlad Serdiuk
1.13	Feb 15, 2016	Updated Black Start Delay risk definition and assumptions	Vlad Serdiuk
1.14	Mar 01, 2016	Added Generation Revenue benefit.	Vlad Serdiuk
1.15	Mar 02, 2016	Added Consequence (100k and None) and Probability levels (1 in 3,333 and 1 in 10,000)	Vlad Serdiuk
1.16	Mar 10, 2016	Corrected cost of energy in Lost Generation Risk description. Added guidelines for: o Generation Revenue benefit o Time Varying benefit o Calculating Consequence to identify the level to use in the Risk Matrix – in progress	Vlad Serdiuk

		o Adding risks to project with no attached assets – in progress Adjusted Black Start delay assumption based on the study conducted by Manitoba Hydro	
1.17	May 13, 2016	Made the following modifications: 1. Adjusted Compliance Risk descriptions based on Manitoba Hydro feedback 2. Updated Section 12.1 with the text for Compliance Risk provided by Manitoba Hydro 3. Made changes to Environmental and Safety Risk descriptions based on Manitoba Hydro feedback	Vlad Serdiuk
1.18	Aug 17, 2016	The following changes were made: 1. Renamed the document to Manitoba Hydro Value Framework Implementation Document (VFID). 2. Removed Regulatory reference in Environmental and Safety risks.	Vlad Serdiuk
1.19	Nov 10, 2016	Made the following corrections: 1. Corrected export energy price typo 2. Removed "Benefit" from Risk Project of Project Execution value measure 3. Adjusted the opening statement in Transmission Reliability Risk	Vlad Serdiuk
1.20	May 23, 2017	Adjusted confidentiality statements	Vlad Serdiuk

1. Summary

The following Value Framework Implementation document is intended to capture all of the information required to fully specify the Value Framework and Function used to evaluate and optimize investments for the organization. This document also captures the relevant processes, methodologies and key assumptions that were used to develop the Value Framework, and, briefly, how the Value Framework is used to evaluate investments and arrive at optimized recommendations.

2. Value-based Decision Making (VDM)

2.1 Introduction to VDM

In order for an organization to optimize the use of its limited resources, it must have a mechanism to determine the relative value of each investment. There are a number of elements that can contribute to the overall value of an investment, such as:

- Impacts to Key Performance Indicators (KPIs)
- Risks mitigated by an investment
- Consequences of a given risk, were they not mitigated
- Financial impacts such as cost savings
- Overall cost of the investment

An investment's net value is then used to determine both its independent merit and its standing among other investments competing for resources in a constrained optimization process.

The process used to generate the Value Framework captured in this document is called Value-Based Decision Making, or VDM, and is an implementation of Multi-Criteria Decision Analysis (MCDA). The VDM approach (Figure 1. Value-based Decision Making Approach) is a best practice in Asset Investment Planning and Management (AIPM) and encourages organizations to:

- Use a value-based approach to guide the development of the decision criteria and the relative weighting of the criteria to one another.
- Use a rational economic approach calibrated to a common scale so dissimilar investments can be compared based on a wide range of criteria.
- Align this model to the objectives and values of the organization to ensure that higher value translates into more success for the organization sooner.
- Use a quantitative, consistent and repeatable approach to assess all benefits.
- Use a risk-informed approach, made by constructing an appropriate risk matrix, to align the mitigation of risk to the common scale ensuring risk is factored into decision-making.
- Ensure that both financial and non-financial benefits are included and that their contributions are aligned to the common scale.
- Use a time-sensitive approach to planning investments that takes into account differing costs and consequences resulting from deferral or acceleration of projects. Timing is crucial.
- Optimize investments across the entire organization to determine the highest total value that can be achieved with the available resources.

- Employ a decision-support solution that delivers transparency, consistency, accuracy, repeatability and rigor to your organization in an efficient and collaborative manner.
- Provide an efficient mechanism to communicate and defend the recommended investment decisions.

The Value-based Decision Making approach can be simplified into two primary activities:

- develop a unique Value Framework that captures the organization`s key value measures, financial parameters and risk matrix, and are aligned with the overall organizational goals;
- and then use this Framework in order to evaluate and optimize potential investments.

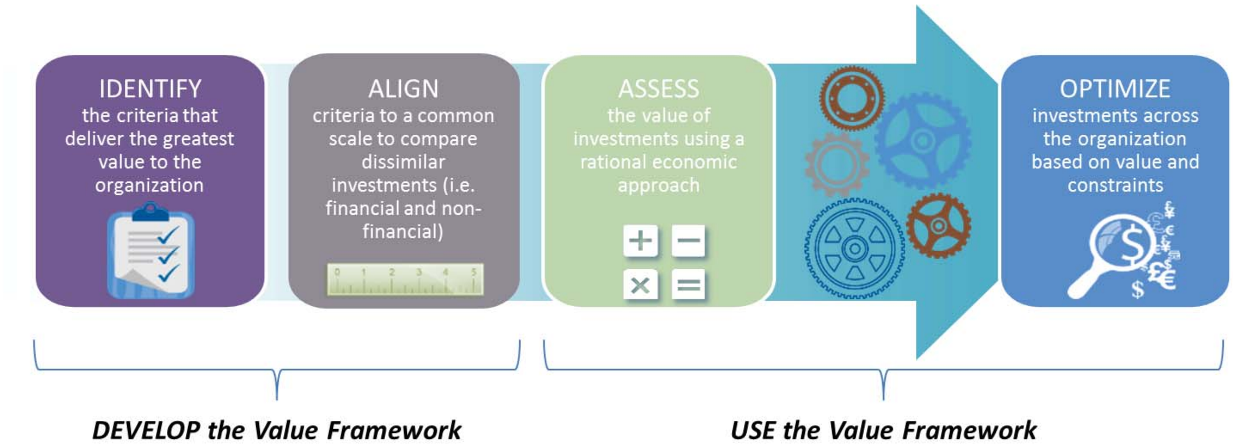


Figure 1- Value-based Decision Making Approach

The Value Framework itself (Figure 2. Value Framework) starts with the organization's strategic goals and the scope of the investments being considered which, in-turn, guide the Value Measures, Risk Matrix and, ultimately, the Value Function. It is also necessary to define and document the financial parameters as well as any detailed supporting calculations, supporting processes, and related assumptions.

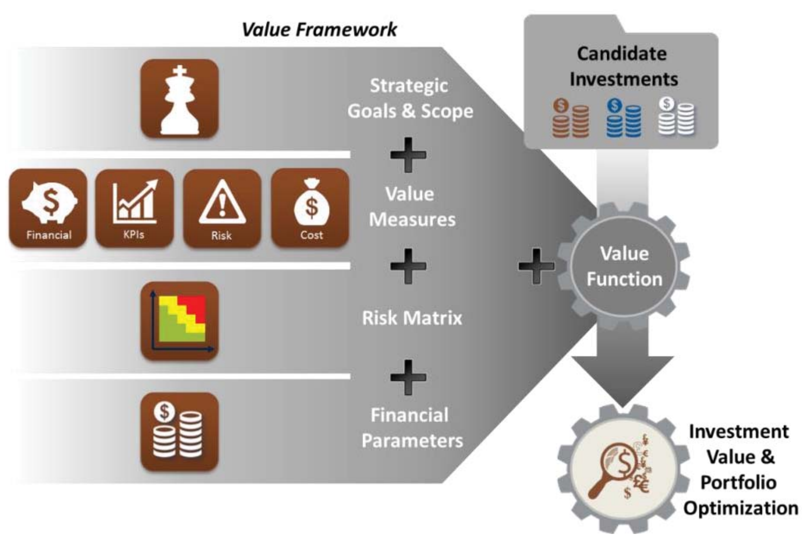


Figure 2 - Value Framework

2.2 Value Measure Types & Criteria

All Value Measures can be classified into four main types: Financial Benefits; Key Performance Indicators; Risk Mitigation; and Cost. Financial Benefit Value Measures capture the Capital and O&M savings such as labor cost saving, fuel cost saving, other capital and/or O&M cost saving, as well as the hard dollar benefit of productivity increases. Value Measures related to Key Performance Indicators also result in productivity and performance increases, but are often expressed as productivity increases due to efficiency improvements. Value Measures related to Risk Mitigation are used to express the benefit of an investment through the reduction of risk. Finally, the Cost of an investment is taken directly from the investment forecast, but may include other costs anticipated as a result of executing the investment (i.e., increases in O&M). The combination of these Value Measures will result in a net value for each investment.

All Benefit Value Measures are calculated using the same criteria: consequence of the investment multiplied by the probability of the benefit being achieved. However, as illustrated in Figure 3, Risk Mitigation Value Measures are calculated using the Risk Matrix which is described in detail below.

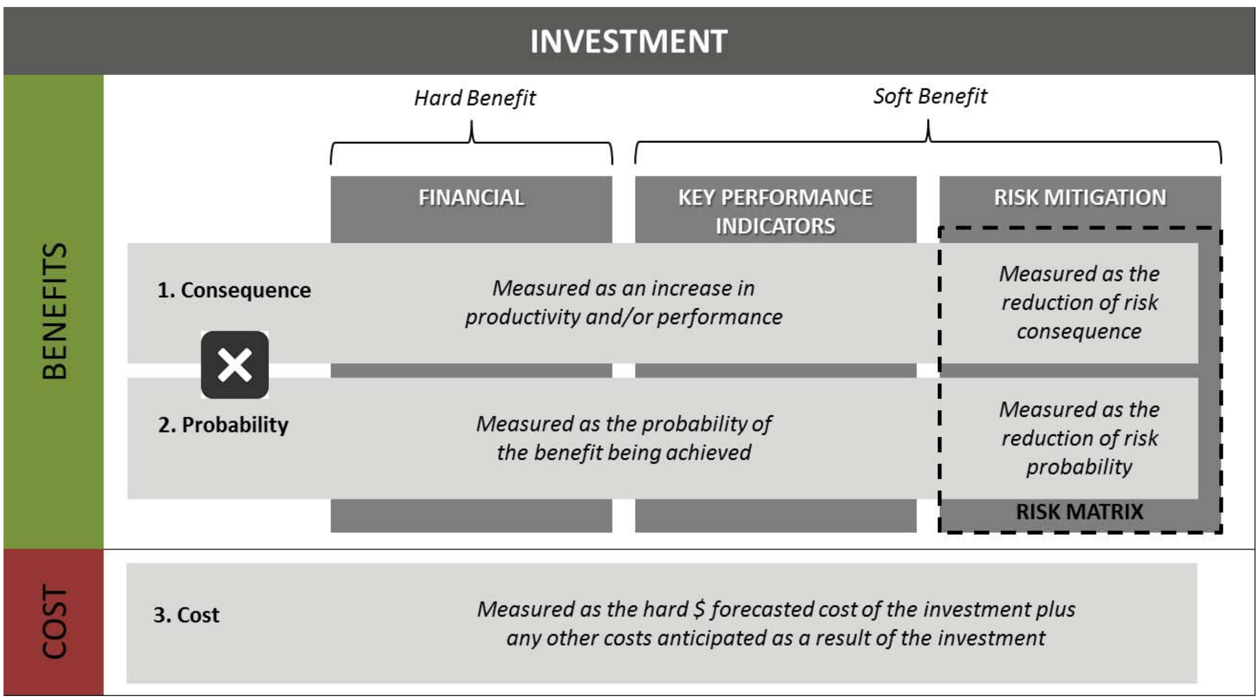


Figure 3 - Value Measure Calculation

2.3 Assessing & Optimizing Investments

As illustrated in Figure 2 above, the Value Function combines all of the Value Measures required to assess and compute the overall value that each investment is bringing to the organization, taking into account its financial benefit, impact on KPI's, risk mitigation, and cost. All investments are then optimized automatically by selecting the combination of start dates and alternatives that will bring the highest total value to the organization while satisfying any financial, resource, or timing constraints.

While each investment may bring value to the organization, it isn't until the investments are compared to one another and financial constraints are applied that it is known whether a specific investment will be funded or not, and in what timeframe. A lower value investment may be delayed in lieu of other, more urgent investments, or may ultimately be deemed unnecessary. Listed below are some general guidelines to help determine the relative value of an investment:

1. **Value.** The net value of the project is visible to the project owner (as well as the components making up that value). A project with a net value less than zero, is a project in which all the benefits specified for the project have a present value less than the present value of the cost. Projects with a net value less than zero should not be considered unless they are considered mandatory for some reason.

2. **Value/$.** A project with a larger net value is bringing more value to the organization; however larger projects typically bring more value than smaller projects. Therefore **Value/$**, (i.e., net value/cost of the investment) can help to compare effectiveness of projects of different sizes.

While these indicators may help create a sense of the relative effectiveness of each investment, neither is a perfect measure of which investment will be preferred by the optimization process since the optimization focuses on how the value (and value/$) changes over time.

3. Organizational Objectives

3.1 Scope of Work

The scope of this exercise was enterprise-wide and included all Manitoba Hydro business units, functional groups, and a sample of investments representing each business unit and functional group.

3.2 Vision

The stated Vision for Manitoba Hydro is:

To be recognized as a leading utility in North America with respect to safety, reliability, rates, customer satisfaction and environmental leadership.

3.3 Goals

The strategic and organizational goals include:

- Increase customer satisfaction: provide reliable, cost-effective distribution service
- Maintain customer service reliability
- Environmental stewardship: maintain the environment for generations
- Public perception
- Financial: Minimize customer rates
- Safety & Regulatory: safety first for our employees & community

4. Investment Types

The following is a list of types of investments that were considered in this exercise:

- Sustainment of Assets
- Growth
- Customer Demand
- Information Technology
- Fleet
- Facilities
- Maintenance Programs
- Asset Sustainment Programs

This list was generated during Workshop 1 where a representative number of investments were discussed and grouped. Several investment types were added in order to capture those investments that are not as common, but occasionally crop up.

5. Financial Parameters & Key Assumptions

Many parameters used in the evaluation and optimization of investments are constant; however, some may change over the planning horizon. The following section captures background information and key assumptions regarding the considerations that were made in the optimization of investments and actual numbers used to evaluate investments, where appropriate.

5.1 Inflation

Inflation for all investments was set as follows:

2015: 2.2%

2016+: 2.0%

5.2 Discount Rate

Weighted Average Cost of Capital used for all investments was set at 6.35% and was provided by Financial Planning.

5.3 Standard Rates, Constants & Key Assumptions

The following section captures the major standard rates, constants, and key assumptions that were used in the Value Measure calculations.

5.3.1 Cost of Export Energy

The cost of export energy ($/MWh) is derived from the average revenue per exported MWh taken from Manitoba Hydro annual report[1]. The extra provincial deliveries in 2014-2015 fiscal year constituted 9,811,000 MWh with revenues of $400 million. That translates into an average export price of $40.77/MWh.

5.3.2 Labor Rate

- **Capital and O&M Labor Rate: LABH = $110/hour**

5.3.3 O&M dollars

O&M costs are funded by the rate payers, therefore each dollar spent by the organization on O&M results in a $1 cost to the rate payer.

- **O&M Exchange: OMXCH = $1**

5.3.4 Capital dollars

When Capital dollars are spent by the organization, the cost to the rate payer is based on the depreciation period of the asset, consisting of:

- Once the asset goes in-Service it becomes part of the organization's capital base
- The capital base gets depreciated based on the accounting asset class, and the depreciation is a cost to the rate payer.

The cost of a capital dollar to the end customer is computed by calculating the impact of the spend for a typical asset life of 30 years and then computing the Present Value using the system discount rate. If one assumes that the customer discount rate is the same as the organization discount rate, then the cost of capital to the rate payer is also $1.

- **Capital Exchange: CAPXCH = $1**

5.3.5 Un-served Energy Costs

The supporting costs of un-served energy are based on industry studies.

Definition for Small, Medium and Large commercial and industrial customers:

Medium and Large C&I (Over 50,000 Annual kWh)

Small C&I (Under 50,000 Annual kWh)

Reference: the estimated average costs for both duration (kWh) and frequency (kW) were taken from study:

UPDATED VALUE OF SERVICE RELIABILITY ESTIMATES FOR ELECTRIC UTILITY CUSTOMERS IN THE UNITED STATES

Prepared for the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy.

- Principle Authors: Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell Nexant, Inc.
- Conducted by: Energy Analysis Department Ernest Orlando Lawrence Berkeley National Laboratory.
- Can be found at: http://eetd.lbl.gov/sites/all/files/lbnl-6941e_0.pdf (the document is also provided)

[1] **MH annual_report_2014_15.pdf** is provided as a supporting document to this VFID.

5.3.6 Customer Distribution Percentages

Customer distribution percentages used in computation of **frequency** and **duration costs** are averages that are determined based on the selection of the customer type in C55. The selection consists of:

- Primarily Residential (<15% Commercial)
- Primarily Commercial (>60% Commercial)
- Mixed
- Critical Public Service

5.3.7 Frequency Cost

The Frequency Costs or the Costs per Event are determined by calculating the weighted average using the estimated average costs per event from the study and applying the average distribution of Commercial and Residential customers. The average cost of Medium and Large C&I customers and Small C&I is used as the average cost for all commercial customers.

Critical Public Service is computed based on the following:

Cost of outage to certain customers providing critical public service will be assigned a “premium” in recognition of the benefit that is provided from these facilities (e.g. hospitals).

“Premium” value is 33% above the cost to commercial customers. The 33% premium is based on a judgmental assessment of the premium associated with these facilities in recognition that these customers are valuable to society because of their critical services. The premium is intended to achieve a fair balance between the critical public service and not being so high such that all work impacting the reliability of service to those facilities get funding. The premium also considers that the facilities have taken measures to provide for their own back-up service for extremely critical operations.

5.3.8 Duration Cost

Duration Costs are computed in a similar manner as the Frequency Costs. They are determined by taking the estimated average costs per un-served kWh from the study and applying the average distribution of Commercial and Residential customers.

Critical Public Service is the same as in frequency cost above (i.e. 33% above commercial customers).

5.3.9 Electrical CMI Cost

CMI (customer minutes of interruption) cost is determined as follows:

- Cost per kWh for Mixed type of customer = cost of un-served kWh from the study times the actual overall distribution of Commercial and Residential customers.
- The mix of Commercial and Residential customers is as follows:
    - Residential: 492,275 or 87.61%
    - Commercial (General Service): 69,594 or 12.39%

- Average power consumption for the organization is 4.56 kW computed from:
    - Average Power Consumption =

      Total Energy Delivered / Total Number of Customers / hours in a year =

      $22{,}458 * 10^6$ / 561,869 / 8,760 = 4.56 kW

Note: Total Energy deliveries and total number of customers were taken from Manitoba Hydro Annual Report for 2014-2015 fiscal year.

- cost per hour = cost per kWh * consumption

Cost per minute = cost per hour / 60 minutes

Table **1 - Cost Summary** below summarizes the Frequency, Duration and CMI costs.

	Primarily Residential (< 15% Commercial)	Mixed Residential & Commercial	Primarily Commercial (> 60% Commercial)	Critical Public Service (Hospital)
$/kW (Frequency Cost)	$15	$61	$127	$169
$/KWh (Duration Cost)	$15	$61	$127	$169
CMI Cost	$1.71			

Table 1 - Cost Summary

5.3.10 Gas CMI Cost

The cost of electrical interruptions is valued at $1.71 per minute of interruption. There are few studies available as to cost of customer outages for gas. It can be assumed that the cost of gas interruptions is lower than electrical interruptions since often gas fired equipment cannot be operated without electricity. Consequently, an estimate of $1.00 per minute is used for gas as it is approximately ½ the cost of an electrical interruption.

5.3.11 Blackstart Delay Cost

If equipment is required to perform a blackstart (in the case of a grid-wide outage) then if the equipment fails then the consequence of such equipment failing is based on the increase in time it would take to perform the blackstart if the equipment is not available. The value of this delay is estimated based on the societal cost of a province-wide outage.

Manitoba Hydro conducted a research to derive societal costs of a system-wide outage. Based on Billinton cost of unserved energy that considers many variables and assumptions, the societal cost of grid-wide outage in Manitoba varies from $49M to about $78M per hour. For the purposes of the Value Framework the grid-wide outage societal cost is assumed to be $60M per hour (approximate average of the range) or $1M per minute.

5.3.12 Avoided Emissions

Survey of information:

- US government generations uses a value of $41/ton for Avoided CO2
- According to Wikipedia http://en.wikipedia.org/wiki/Carbon_tax, carbon taxes are in the range of $10 to $100 per tonne of C02
- Forbes article http://www.forbes.com/2009/06/03/cap-and-trade-intelligent-investing-carbon.html puts the price in the range of $20 to $30 per tonne of CO2

- CBC news http://www.cbc.ca/news/business/u-s-ups-social-cost-of-carbon-emissions-1.1330833 states that the US has increased the social cost it uses in evaluation projects from $22 USD/metric tonne to $36 USD/metric tonne

Based on this survey, avoided CO_2 can be valued at $40/tonne.

5.3.13 Average Weighted Price of Energy

- $40.77/MWh is used as the cost of export energy based on Manitoba Hydro exports (see section 5.3.1 Cost of Export Energy)

5.3.14 Cost of Transmission Line Outage

Customer Value of Δ EUE (estimated unserved energy)

- Δ EUE calculations are described in the proof of concept document:
  - Manitoba Hydro T Stage 1 Recommendations_Test Report v4.pdf

5.3.15 Secondary Failure Probability

Secondary Failure is the likelihood of a secondary failure in a redundant system. This calculation is complex and varies from situation to situation; therefore, 5% has been chosen as a reasonable average expectation. This figure represents the probability of the secondary failure as well as the probability that maintenance work will have to be delayed due to the loss of redundancy. The 5% value has been used by Copperleaf at other utilities.

5.3.16 Investment Impact

The value gained through certain investments can often be subjective. Whether the Value Measure is impacting a Customer or an Employee, sometimes the only way to assess the value of the investment may be to subjectively identify if the impact is expected to be minor or significant. For such Value Measures, investment impact for both customers and employees are as follows:

- Very Significant: 10% or more
- Significant: 3%
- Moderate: 1%
- Minor: less than 1%

Further factoring can be applied using the probability of the benefit being achieved, as explained below in Section 8 Value Measures: Financial.

5.3.17 Soft & Hard Probability

Some Value Measures are much easier to quantify than other Values. For instance, Employee Productivity Benefits can usually be traced directly to individuals who will save specific amounts of time due to improved efficiencies. The probability of the benefit being achieved is very high (i.e., 100%). Productive Workplace Benefit, on the other hand, doesn't directly affect productivity and the gains to the organization or the end customer are much more subjective. It is common for these softer benefits to use a probability of 50% to indicate the subjective nature of the Value Measure benefit and its likelihood of being achieved. These probabilities are entered via the benefits questionnaires in each Value Measure.

6. Risk Matrix

As described above, Risk is defined as the probability of an event occurring multiplied by the consequence of that event. The Risk Matrix is built around the risk types that are important to the organization (i.e. safety, environmental, lost production, etc.) and the associated consequences by severity level. It is essential that the consequence levels are aligned across the different risk types.

6.1 Consequence Definition

The definition of the consequence levels was developed by first looking at the overall range of consequences (usually starting with financial consequences). Once the range was established, consequence levels are created such that each level increases non-linearly (usually between 3x to 10x increase per level). This provides a clear progression between levels where changing a consequence level results in a meaningful, conclusive change.

Existing Manitoba Hydro risk consequences were aligned with the more granular consequence levels to provide flexibility for investment risk evaluation.

CONSEQUENCE	CONSEQUENCE 100,000	CONSEQUENCE 30,000	CONSEQUENCE 10,000	CONSEQUENCE 3,000	CONSEQUENCE 1,000	CONSEQUENCE 300	CONSEQUENCE 100	CONSEQUENCE 30	CONSE-QUENCE 0
Financial	>$50 million annually	>$15 million annually	>$5M annually	>$1.5 million annually	>$500K annually	>$150K	>$50K annually	<$50K annually	None
IT Capacity	N/A	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 1500 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 500 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 150 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 50 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 15 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 5 employees.	Lack of capacity (or currency) of a system that impacts significantly (e.g. 10% average decrease in productivity) for more than 1 employee.	None
Export Transfer Capacity	Lost revenue due to inability to export > $50M annually	Lost revenue due to inability to export > $15M annually	Lost revenue due to inability to export > $5M annually	Lost revenue due to inability to export > $1.5M annually	Lost revenue due to inability to export > $500K annually	Lost revenue due to inability to export > $150K annually	Lost revenue due to inability to export > $50K annually	Lost revenue due to inability to export < $50K annually	None
Lost Generation	Calculated risk > $50M annually	Calculated risk > $15M annually	Calculated risk > $5M annually	Calculated risk > $1.5M annually	Calculated risk > $500K annually	Calculated risk > $150K annually	Calculated risk > $50K annually	Calculated risk < $50K annually	None

CONSEQUENCE	CONSEQUENCE 100,000	CONSEQUENCE 30,000	CONSEQUENCE 10,000	CONSEQUENCE 3,000	CONSEQUENCE 1,000	CONSEQUENCE 300	CONSEQUENCE 100	CONSEQUENCE 30	CONSE-QUENCE 0
Blackstart Delay	Delay in grid-wide blackstart of 1 hour	Delay in grid-wide blackstart of 30 minutes	Delay in grid-wide blackstart of 10 minutes	N/A	N/A	N/A	N/A	N/A	None
Transmission Reliability	Customer Value of Δ EUE (estimated unserved energy) > $50M annually	Customer Value of Δ EUE (estimated unserved energy) > $15M annually	Customer Value of Δ EUE (estimated unserved energy) > $5M annually	Customer Value of Δ EUE (estimated unserved energy) > $1.5M annually	Customer Value of Δ EUE (estimated unserved energy) > $500K annually	Customer Value of Δ EUE (estimated unserved energy) > $150K annually	Customer Value of Δ EUE (estimated unserved energy) > $50K annually	Customer Value of Δ EUE (estimated unserved energy) < $50K annually	None
Electrical Delivery Capacity	N/A	Unable to service a new load	Can supply all load but exceeding thermal limits	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range (e.g. below 113V) for distribution supply system (66KV, 33KV, 24KV lines and distribution stations)	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range (e.g. below 113V) for distribution feeder mains	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range (e.g. below 113V) for distribution feeder taps	N/A	Able to supply load without exceeding planning limits.	None
Gas Delivery Capacity	N/A	Unable to service a new load	N/A	Can supply all load but exceeding planning limits	N/A	N/A	N/A	Able to supply load without exceeding planning limits.	None
Import Transfer Capacity	Customer Value of Unserved Energy > $50M annually	Customer Value of Unserved Energy > $15M annually	Customer Value of Unserved Energy > $5M annually	Customer Value of Unserved Energy > $1.5M annually	Customer Value of Unserved Energy > $500K annually	Customer Value of Unserved Energy > $150K annually	Customer Value of Unserved Energy > $50K annually	Customer Value of Unserved Energy < $50K annually	None

CONSEQUENCE	CONSEQUENCE 100,000	CONSEQUENCE 30,000	CONSEQUENCE 10,000	CONSEQUENCE 3,000	CONSEQUENCE 1,000	CONSEQUENCE 300	CONSEQUENCE 100	CONSEQUENCE 30	CONSE-QUENCE 0
Environmental	N/A	Severe environmental impact (as per EMS Risk Ranking Criteria). Significant compensation, remediation or restoration required > $15M	Severe environmental impact (as per EMS Risk Ranking Criteria). Significant compensation, remediation or restoration required costing >$5M	Moderate environmental impact (as per EMS Risk Ranking Criteria). Some compensation, remediation or restoration required, costing >$1.5M	Moderate environmental impact (as per EMS Risk Ranking Criteria). Some compensation, remediation or restoration required, costing >$500K	Limited impact on environment (as per EMS Risk Ranking Criteria); Limited compensation, remediation or restoration required, costing >$150K	Limited impact on environment (as per EMS Risk Ranking Criteria); Limited compensation, remediation or restoration required, costing >$50K	Immaterial consequence	None
Safety	Unmitigated risk of community destruction and multiple fatalities, or serious injuries when the cost of a work around would exceed the cost of the investment	Possibility of injury has been mitigated by operating restriction where the cost of those restriction is >$15M or result in > 9M CMI annually **OR** unmitigated risk of multiple fatalities where no workaround is possible or the cost of the workaround exceeds the cost of the investment	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions is > $5M or result in > 3M CMI annually **OR** Unmitigated risk of serious injury (e.g. disabling injury) or fatality where no workaround is possible **OR** Investment targets alignment with Organization' or industry current best practices for safety. Select a probability of Once in 1000 years in this case.	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions is > $1.5M or result in > 900K CMI annually	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions is > $500K or result in > 300K CMI annually **OR** unmitigated risk of injury requiring medical attention	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions is > $150K or result in > 90K CMI annually **OR** unmitigated risk of first aid injury	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions is > $50K or result in > 30K CMI annually	Immaterial consequence	None
Security	Physical or cyber security breach resulting in damage > $50M	Physical or cyber security breach resulting in damage > $15M	Physical or cyber security breach resulting in damage > $5M	Physical or cyber security breach resulting in damage > $1.5M	Physical or cyber security breach resulting in damage > $500k	Physical or cyber security breach resulting in damage > $150k	Physical or cyber security breach resulting in damage > $50k	Physical or cyber security breach resulting in damage < $50K	None

CONSEQUENCE	CONSEQUENCE 100,000	CONSEQUENCE 30,000	CONSEQUENCE 10,000	CONSEQUENCE 3,000	CONSEQUENCE 1,000	CONSEQUENCE 300	CONSEQUENCE 100	CONSEQUENCE 30	CONSE-QUENCE 0
Compliance	**N/A**	Violation of Operating License requirements, federal or provincial law where the penalty could be a jail sentence	**N/A**	Violation of Federal or Provincial Law (including NERC Requirement) where a fine will be greater because of a repeat offense	First-time violation of Federal or Provincial Law (including NERC Requirement)	Violation of a Corporate Standard	**N/A**	**N/A**	None
Public Perception	N/A	Adverse national media publicity **OR** Public Inquiry, federal inquiry (FAI) **OR** Significantly undermine relations with First Nations	N/A	Long term adverse local media publicity **OR** Public confidence in the organization undermined **OR** Significant effect on staff morale, public and community perception of the organization.	N/A	Short term local adverse media coverage **OR** Some public embarrassment **OR** Minor effect on staff morale/public/community attitudes.	Commitment to the province, municipality or community (e.g. enables information sharing, contribution to community)	Immaterial consequence	None

Table 2 - Consequence Levels

6.2 Probability Definition

The definition of probability levels follows a similar principle to consequence in order to get adequate differentiation between levels; however, the range doesn't need to be determined as it is between 0 and 100%. Again, an increase of 3x to 10x between levels is the norm. The types of risk events that are being considered may also impact the definitions of probability levels.

Existing Manitoba Hydro risk probability levels were aligned with the more granular probability levels to provide flexibility for investment risk evaluation.

Almost Certain	Once in 3 years	Once in 10 years	Once in 33 years	Once in 100 years	Once in 333 years	Once in 1000 years	Once in 3333 years	Once in 10000 years	None
Imminent (>95% chance of occurring this year)	Approximately 30% chance of event occurring this year (e.g. 1 in 3-year event)	Approximately 10% chance of event occurring this year (e.g. 1 in 10-year event)	Approximately 3% chance of event occurring this year (e.g. 1 in 33-year event)	Approximately 1% chance of event occurring this year (e.g. 1 in 100-year event)	Approximately 0.3% chance of event occurring this year (e.g. 1 in 333-year event)	Approximately 0.1% chance of event occurring this year (e.g. 1 in 1,000-year event)	Approximately 0.03% chance of event occurring this year (e.g. 1 in 3,333-year event)	Approximately 0.01% chance of event occurring this year (e.g. 1 in 10,000-year event)	Event unlikely to occur in next 10,000 years

Table 3 - Probability Levels

6.3 Risk Matrix

The Risk matrix was developed by combining the existing Manitoba Hydro risk matrix and the risk matrix developed by Copperleaf in line with the best practices.

The Value of Risk Mitigation in all risk categories is computed using the same methodology. Mitigated Risk is computed directly in Value Units therefore the conversion factor for the Value Measure is 1. Each risk is evaluated by selecting the appropriate Consequence and Probability of that consequence as per the definitions provided in Tables 1 and 2, and then converted into values using the Risk Matrix below (see Figure 4). The value is computed per year and the total value is determined by taking the present value of the stream.

The project owner specifies:

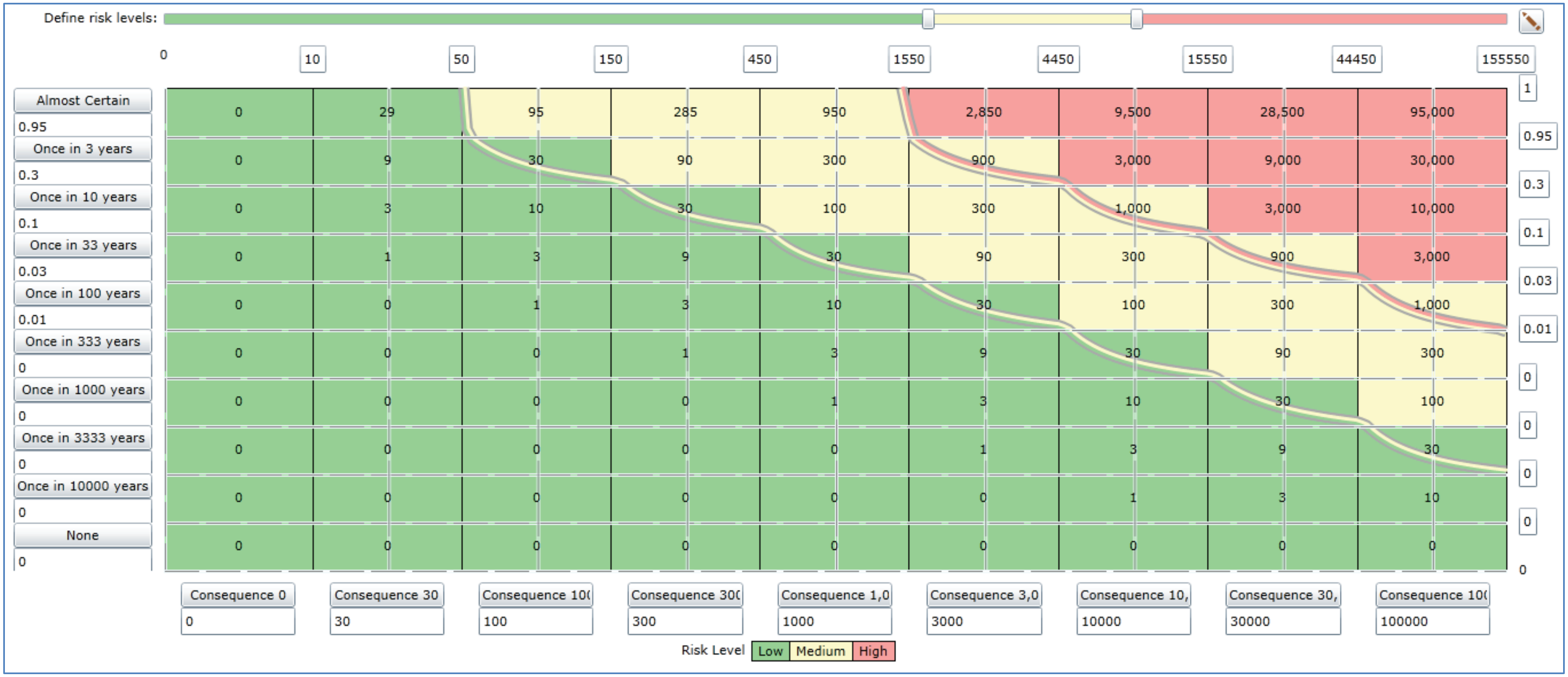
Baseline Risk: The risk present if the project is not completed.

Residual Risk: The risk present if the project is completed.

Value of Risk Mitigated is computed as:

Mitigated Risk = Baseline Risk – Residual Risk

Whereas the Financial Value Measures and the KPI Value Measures required an estimate for both the financial consequence and the probability of recognizing that benefit, these two elements are derived from the Risk Matrix when evaluating risks.



	Consequence 0 (0)	Consequence 30 (30)	Consequence 100 (100)	Consequence 300 (300)	Consequence 1,000 (1000)	Consequence 3,000 (3000)	Consequence 10,000 (10000)	Consequence 30,000 (30000)	Consequence 100,000 (100000)
Almost Certain (0.95)	0	29	95	285	950	2,850	9,500	28,500	95,000
Once in 3 years (0.3)	0	9	30	90	300	900	3,000	9,000	30,000
Once in 10 years (0.1)	0	3	10	30	100	300	1,000	3,000	10,000
Once in 33 years (0.03)	0	1	3	9	30	90	300	900	3,000
Once in 100 years (0.01)	0	0	1	3	10	30	100	300	1,000
Once in 333 years (0)	0	0	0	1	3	9	30	90	300
Once in 1000 years (0)	0	0	0	0	1	3	10	30	100
Once in 3333 years (0)	0	0	0	0	0	1	3	9	30
Once in 10000 years (0)	0	0	0	0	0	0	1	3	10
None (0)	0	0	0	0	0	0	0	0	0

Figure 4- Risk Matrix

The value for each value in the risk matrix is computed by multiplying the middle value of the consequence by the middle value of the probability. For example, a “Consequence 10,000” consequence has a middle value of “10,000” (average of 4,450 and 15,550) and an event occurring at least every “Once in 10 years” has a value of 0.1. The result is that a “Consequence 10,000” consequence event with a frequency greater than once in 10 years is valued at 1,000 Value Units. For risk types such as “Lost Generation Risk” where the probability and consequence are calculated based on the asset attributes, or for “Transmission Reliability” where the impact is calculated by a model, the computed value units are used as the models provide a more accurate placement on the risk matrix (i.e. not just the cell in the Risk Matrix).

7. Value Function

7.1 Value Perspective

For all Value Measures used in the Value Function, "value" was defined as the value delivered to the end customer as opposed to value delivered to the organization.

7.2 Value Function Summary

All investments are valued and optimized based upon a Value Function. The Value Function is a weighting of a number of Value Measures that are sometimes grouped into broader categories and are aligned with the organization's strategic and operational objectives. The Value Function is configurable to reflect how each investment will contribute to the organization.

This summary table was developed through 3 workshops and included stakeholders from all business units and functional groups. The organizational goals were central to the development of the Value Measures, and additional Value Measures were added and refined after reviewing some of the potential investments.

The table below summarizes the Value Measures and associated conversion factors used in the Value Function in order to evaluate each investment.

Value Measure Categories	Value Measures	Conversion Factor	Polarity	Organizational Goals
• Financial	• Capital Financial Benefit	0.001	+	• Maximize cost savings and increase efficiency
	• O&M Financial Benefit	0.001	+	
	• O&M Costs	0.001	-	
	• Financial Risk*	Risk Matrix	+	
	• IT Capacity Risk*	Risk Matrix	+	
	• Lost Generation Risk**	Risk Matrix	+	
	• Export Transfer Capacity Risk*	Risk Matrix	+	
	• Productive Workplace Benefit	1	+	
	• Risk of Project Execution (non-ITS)	0.001	-	
	• Risk of Project Execution (ITS)	0.001	-	
	• Varying Cost or Revenue Benefit	0.001	- or +	
	• Generation Revenue Benefit	0.001	- or +	
	• Investment Cost	0.001	-	
• Reliability	• Transmission Reliability Risk*	Risk Matrix	+	• Maintain customer service reliability
	• Electrical Delivery Capacity Risk*	Risk Matrix	+	
	• Gas Delivery Capacity Risk*	Risk Matrix	+	
	• Import Transfer Capacity Risk*	Risk Matrix	+	
	• Blackstart Delay Risk*	Risk Matrix	+	

Value Measure Categories	Value Measures	Conversion Factor	Polarity	Organizational Goals
	• Distribution Reliability Benefit	1	+	• Increase customer satisfaction
	• Distribution Outage Recovery Benefit	1	+	
	• Gas Distribution Reliability Benefit	1	+	
• Environmental	• Environmental Benefit	1	+	• Environmental stewardship
	• Environmental Risk*	Risk Matrix	+	
• Safety	• Safety Risk*	Risk Matrix	+	• Safety first for employees & community
	• Security Risk*	Risk Matrix	+	
• Corporate Citizenship	• Compliance Risk*	Risk Matrix	+	• Public perception
	• Public Perception Risk*	Risk Matrix	+	
	• Customer Service Benefit	1	+	

Table 4 - Value Function Summary

*Manually entered risks, i.e. entering the risk profile for baseline and residual risk, receive Value Units based on the Risk Matrix (see section 6.3 Risk Matrix).

** Lost Generation is calculated automatically in dollars based on the asset attributes and is calibrated to the Value Measure by applying the conversion factor of 0.001.

As described in the sections below, each of the Value Measures is calibrated to the same scale: 1 value point is approximately equal to $1,000 of customer value. The Benefits are calibrated to the Value Measures using the conversion factors listed above.

All Value Measures are computed on a monthly or annual basis (e.g. the financial benefits for 2017 can be specified as being different than 2018). The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value (PV) of the stream, back to the beginning of the current fiscal year. The PV calculation uses the discount rate as defined in section 5.2 Discount Rate.

8. Value Measures: Financial

The following sections capture the detailed information for each Value Measure used in the Value Function. The information includes, among other things, a definition of the Value Measure, questionnaires (where appropriate), relevant organization and/or industry rates or figures, and the resulting equation. Example investments or projects are also included as a reference for each Value Measure.

8.1 Capital Financial Benefits

Capital Financial Benefits is used to measure Capital savings such as labour cost saving, efficiency improvements, other capital cost savings. Financial Benefit Type variable determines whether the savings would result in the tangible future cost reduction (Expected Reduction), cost avoidance (Avoided Cost) or productivity improvement (Efficiency Benefit). Probability of benefit achievement for Expected Reduction is always considered to be 100% whereas Avoided Cost and Efficiency Benefit allow for adjustments to account for uncertainty in the benefit realization.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Financial Benefit Type	Enumeration	TYPE	Selection: o Expected Reduction o Avoided Cost o Efficiency Benefit o Revenue
Labour Savings (hours per year)	Number	LABH	
Other Capital Cost Savings or Revenue (dollars per year)	Number	COST	
Type of Other Capital Cost Savings or Revenue	Enumeration	TYCO	Select Not Applicable if no "Other Capital Cost Savings" identified. Selection: o Not Applicable o Contract o Materials o Proceeds from Sale o Other
Probability of Benefit Achievement (for Avoided Cost and Efficiency Benefits). (%)	Number	PROB	What is the % likelihood that an Avoided Cost or Efficiency Benefit will be achieved? Enter 15% as "15." Expected Reduction benefits are always valued at 100%.
Provide the rationale or assumptions for the answers provided above.	Text	TEXT	

Examples of Benefits Types:

Expected Reduction benefit type:
This benefit type measures a tangible reduction that can be applied to future budget. For example, a change to the project is made such that services of an outside contractor are no longer needed. Therefore, the contractor position can be eliminated saving Manitoba Hydro the cost of the contractor. The budget for the years following the contractor elimination can be reduced by the amount saved. The probability of this benefit type is fixed at 100% because once it is determined that a contractor costs will be avoided the amount of savings is certain.

Avoided Cost benefit type:
This benefit type measures the potential expenditures that would be avoided as a result of the project. To reflect the uncertainty in measuring and achieving the avoided costs the probability factor can be applied. For example, the project targets installing automated digital fault detectors. The new equipment would save hours of crew time by reporting the exact location of faults that would otherwise have to be determined manually by Manitoba Hydro CS&D crews. In this example, the probability of realizing the benefit is 100% as it is certain that the equipment will automatically determine and report fault information to the control.

Efficiency benefit type:
This benefit type is aimed at measuring productivity improvements. To reflect the uncertainty in measuring and achieving productivity gains the probability factor can be applied. For example, new software can enable employees to perform their day-to-day tasks faster. The time savings can be utilized by the employees to perform additional tasks. For demonstration purposes, let's say that the probability of employees taking advantage of the time savings is 75% meaning that that 3/4 of the employees will become more productive as result of the project.

Revenue benefit:
This benefit type is used to record the revenue realized as part of the project. For example, proceeds received from sale of an asset.

8.2 O&M Financial Benefits

O&M Financial Benefits is used to measure O&M savings such as labour cost saving, productivity improvements, other O&M cost savings. Financial Benefit Type variable determines whether the savings would result in the tangible future cost reduction (Expected Reduction), cost avoidance (Avoided Cost) or productivity improvement (Efficiency Benefit). This benefit is similar to Capital Financial only is targeted at O&M expenditures.

Expected Reduction, Avoided Cost, and Efficiency Benefit carry the same meaning in this value measure as in the Capital Financial Benefits value measure. Expected Reduction measures tangible cost elimination, Avoided Cost measures projected cost avoidance, and Efficiency Benefit measures productivity gains. Probability of benefit achievement for Expected Reduction is always considered to be 100% whereas Avoided Cost and Efficiency Benefit allow for adjustments to account for uncertainty in the benefit realization.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Financial Benefit Type	Enumeration	TYPE	Selection: o Expected Reduction o Avoided Cost o Efficiency Benefit
Labour Savings (hours per year)	Number	LABH	
Other OM&A Cost Savings (dollars per year)	Number	COST	
Type of Other OM&A Cost Savings	Enumeration	TYCO	Select Not Applicable if no "Other OM&A Cost Savings" identified. Selection: o Not Applicable o Contract o Materials o Other
Probability of Benefit Achievement (for Avoided Cost and Efficiency Benefits). (%)	Number	PROB	What is the % likelihood that an Avoided Cost or Efficiency Benefit will be achieved? Enter 15% as "15." Expected Reduction benefits are always valued at 100%.
Provide the rationale or assumptions for the answers provided above.	Text	TEXT	

8.3 O&M Costs

O&M Costs is aimed at measuring any O&M costs that would be added as a result of completing the project. It is a negative contributor to the project value and typically occurs on projects that create additional maintenance upon project completion.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Labour Costs (hours per year)	Number	LABH	
Other OM&A Costs (dollars per year)	Number	COST	
Type of Other OM&A Costs	Enumeration	TYCO	Select Not Applicable if no "Other OM&A Costs" identified. Selection: o Not Applicable o Contract o Materials o Annual Maintenance

Variable Prompt	Variable Type	Variable Name	Variable Description
			o Annual License o Other
Provide the rationale or assumptions for the answers provided above.	Text	TEXT	

8.4 Financial Risk

As described above, the value of Risk Mitigation in all risk categories is computed using the same methodology. Mitigated Risk is computed directly in Value Units, therefore the conversion factor for the Value Measure is 1. Each risk is evaluated by selecting the appropriate Consequence and Probability of that consequence and then converted into values using the Risk Matrix. The value is computed per year and the total value is determined by taking the present value of the stream.

Financial risk is used to represent a failure mode or an event that will have a direct financial consequence for the organization. For example, if the failure of a piece of auxiliary equipment causes the destruction of a turbine unit, there would be a financial risk associated with that failure whose consequence is valued at the cost of repair or replacement of the turbine. The investment will reduce either the probability of the event, the consequence of the event, or both.

8.5 IT Capacity Risk

IT capacity risk represents the potential productivity impact of failing to meet the organization's IT requirements. An example of IT capacity risk would be a network link between sites that potentially does not have the bandwidth required to support all of the users at one site.

Assessment of IT capacity risk is based on the number of users whose productivity would likely be significantly impacted by the insufficiency.

IT Capacity consequences are aligned with financial consequences as follows:

- The productivity of an average employee is valued at $100,000 per year.
- A significant impact is assumed to be a 10% reduction in efficiency.
- Thus, IT capacity risk is assumed to be equivalent to $10,000 per affected employee.

An investment to improve IT Capacity may reduce the number of employees potentially affected (i.e., reduced consequence), or may reduce the probability of the event, thus mitigating the risk and adding value to the organization.

8.6 Lost Generation Risk

Lost Generation risk is used to represent the impact of the unavailability of generation capacity on the grid. Loss of generation is calculated based on the cost to replace (or not sell) the power that is not generated.

The Lost Generation risk is computed from unit capacity lost (MW) from an outage and the direct cost associated with replacing the failed unit.

8.7 Export Transfer Capacity Risk

Export Transfer Capacity risk measures the risk of being unable to sell exports due to transmission equipment being unavailable. The risk consequence is computed by determining the expected impact in MWh on exports and using the average price of exports computed in section 5.3.1 Cost of Export Energy ($40.77/MWh).

i.e. Export Transfer Capacity Risk =

Expected impact on exports (MWh) * Average Price of Exports ($40.77/MWh)

8.8 Productive Workplace Benefit

Productive Workplace Benefit is aimed at measuring the effects of working conditions on employee productivity. While this benefit is subjective, poor working conditions do affect employee productivity and the ability of the organization to attract and retain employees.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
How many employees are at significant risk of leaving the company (or their current position) if these improvements are not made?	Number	EMPL	
How many employees are affected by these workplace improvements?	Number	EMPE	
What impact are the workplace improvements expected to have on the productivity of employees?	Enumeration	IMP	Selection: o Very Significant o Significant o Moderate o Minor
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

8.9 Risk of Project Execution (non-ITS)

Risk of project execution is a measure that quantifies the accuracy of project cost estimate expressed in contingency (or confidence) levels. The standard unit of measure of the contingency levels is the Estimate Class. Even though the Estimate Class's estimate accuracy is a range of both positive and negative percentage of the cost of a project, it is reasonable to assume a conservative approach and only include the contingency (i.e. positive % addition to project costs). This measure is a negative contributor to the overall value of a project because it adds contingency to the cost of the project. It is configured as a negative benefit in C55.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
What is the total project cost?	Number	COST	
What is the Estimate Class for this project?	Enumeration	ESTC	Selection: o Estimate Class 1 o Estimate Class 2 o Estimate Class 3 o Estimate Class 4
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

8.10 Risk of Project Execution (ITS)

Risk of Project Execution for ITS is different from the non-ITS risk of project execution in that it uses a different method to express the project execution risk. The non-ITS risk of project execution uses Estimate Class as the measure of the estimate accuracy whereas ITS value measure uses Customer Care & Energy Conservation IT Coordinating Committee (ITCC) Risk Scoring Matrix to calculate the risk score for achieving project goals.

To align this value measure with non-ITS's, a total weighted score of 10 is assumed to represent 50% (Estimate Class 1) increase in the project estimate. This measure is a negative contributor to the overall value of a project because it adds contingency to the cost of the project. It is configured as a negative benefit in C55.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions and providing the risk level for each of the project goals listed in Variable Prompt column:

Variable Prompt	Variable Type	Variable Name	Variable Description
What is the total project cost?	Number	COST	
Stakeholder Support including stakeholder involvement and support of project regarding expected organizational change. Weighting = 4.0	Enumeration	SSUP	Division Managers and key stakeholders are aware and fully support this initiative. Selection: o Level 1 (=10 points) – High Risk o Level 2 (=7 points) o Level 3 (=5 points) o Level 4 (=2 points) – Low Risk
Organizational Change includes the readiness of the business to embrace organizational change to implement proposed initiative. Weighting = 3.0	Enumeration	OSUP	New software to replace existing spreadsheets, however is a platform already familiar with most users; small learning curve expected. Selection:

Variable Prompt	Variable Type	Variable Name	Variable Description
			o Level 1 (=10 points) – High Risk o Level 2 (=7 points) o Level 3 (=5 points) o Level 4 (=2 points) o Level 5 (=0 points) – Low Risk
System Solution Dependencies addresses the extent of dependencies with other IT or business initiatives and the degree of business control over the dependencies. Weighting = 3.0	Enumeration	SYSD	No conflicting projects relating to the proposed solution; however competing projects for resources to develop the solution. Selection: o Level 1 (=10 points) – High Risk o Level 2 (=7 points) o Level 3 (=5 points) o Level 4 (=2 points) o Level 5 (=0 points) – Low Risk
Project Size & Complexity of the proposed project including: project effort and time requirements, clarity of requirements definition, complexity of environment / solution and level of project experience. Weighting = 5.0	Enumeration	PSPC	Small - combined effort estimated at 80 days. Selection: o Level 1 (=10 points) – High Risk o Level 2 (=7 points) o Level 3 (=5 points) o Level 4 (=2 points) – Low Risk
Resource Availability & Skill Sets includes whether sufficient business and IT resources are available with the right skills and experience to ensure a successful outcome. Weighting = 5.0	Enumeration	RASS	All resources have all knowledge required to complete the project, however more time needs to be spent defining the requirements and additional time maybe required for additional IT resources to become available. Selection: o Level 1 (=10 points) – High Risk o Level 2 (=7 points) o Level 3 (=5 points) o Level 4 (=2 points) – Low Risk
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

8.11 Varying Cost or Revenue Benefit

Varying Cost or Revenue Benefit is designed to capture changes to the project budget as the project is shifted. These changes can be either positive (Revenue) or negative (Cost). Delaying a project may result in additional expenses or reduced revenue. Advancing the project may result in increased revenue or reduced costs. This benefit is different from other financial benefits in that it changes as the project is shifted. The change is dictated by the resource price stream associated with the benefit that serves as the multiplier to the amount of the change entered in the questionnaire. The multiplier must be setup for each situation being modeled.

It is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Supplier			Supplier in C55
Resource			Resource in C55
Charge Type	Enumeration	TYPE	Selection: o Cost o Revenue (or Savings)
Amount (dollars per year)	Number	AMNT	
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

8.12 Generation Revenue Benefit

Generation Revenue Benefit is designed to capture generation revenue changes as a result of the project. These changes can be either positive (Gain) or negative (Loss). A project may result in capacity gain and additional revenue. A project may also result in modifications leading to capacity or generation reduction or revenue loss. The computation of the benefit takes into account the price of energy by station (the same energy price as used in Asset Analytics) and the utilization of the generating unit affected by the project.

The benefit is computed in dollars and then calibrated to the Value Measure by applying the conversion factor of 0.001 since all other Value Measures are normalized to $1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Supplier			Supplier in C55 (Generating Station)
Resource			Resource in C55 (MWh)
Revenue	Enumeration	TYPE	Selection: o Gain

Variable Prompt	Variable Type	Variable Name	Variable Description
			o Loss
Amount (in MW)	Number	AMNT	
Generation Group	Enumeration	GGRP	Selection: o <Generation Group> e.g. Great Falls - 1
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

8.13 Cost of the Investment

The investment (or project) cost is computed in dollars and comes directly from Outlook. Like Financial Benefits, investment cost has a conversion factor of 0.001 in order to normalize it to the Value Measure scale. Cost is the negative contributor to the overall value of the project.

9. Value Measures: Reliability

9.1 Distribution Reliability Benefit

The Distribution Reliability Benefit value is based on the maximum of three computations: cost of outage frequency, cost of outage duration, and customer minutes of interruption. A combination of industry studies and organization statistics is used in the calculation and a detailed description of these industry studies can be found in Copperleaf White Paper - AIPM and Value-Based Reliability Planning v1.0.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
How many failures per year will be avoided by implementing this project?	Number	FAIL	If there is only a small probability of a failure each year, enter the probability as a decimal (e.g. 5% chance of occurring in a year, enter as 0.05). If this investment increases the likelihood of failures enter as a negative number.
For each of the failures what would be the expected Peak Lost Load, or in the case of redundant equipment the Peak load at risk (kVA)	Number	PEAK	
What is the average duration of the outage caused by the failures? (hours)	Number	DUR	
In the case of redundant equipment, what is the duration for which the redundancy will be lost? (hours)	Number	DURR	
What is the average number of customers impacted by each failure?	Number	NCUS	
Customer Type	Enumeration	TYPE	Select "Residential" if it is unclear what the customer type is. Selection: o Primarily Residential (< 15% Commercial) o Mixed Residential / Commercial o Primarily Commercial (> 60% Commercial) o Critical Public Service (Hospital)
Has this feeder been identified as a worst performing feeder report in the past 2 years?	Enumeration	WORS	Selection: o Yes o No

Variable Prompt	Variable Type	Variable Name	Variable Description
Enter benefit computed using method other than this questionnaire (e.g. Program Analytics)	Number	BNFT	This field is used for benefit that was computed elsewhere (i.e. not using this questionnaire)
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

The Distribution Reliability Value Measure is computed as a sequence of steps:

1. Compute the reduced cost of Customer Minutes of Interruption (CMI)
2. Compute the decrease in Frequency Cost
3. Compute the decrease in Duration Cost

4. Distribution Reliability Cost savings is computed based upon the maximum customer cost of:
   - Interrupted Power (CMI Cost)
   - Interruption Frequency (Frequency Cost)
   - Interruption Duration (Duration Cost)

9.2 Gas Distribution Reliability Benefit

The Gas Distribution Reliability Benefit value similar to the Distribution Reliability Benefit but is based only on the customer minutes of interruption (CMI cost).

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
How many failures per year will be avoided by implementing this project?	Number	FAIL	If there is only a small probability of a failure each year, enter the probability as a decimal (e.g. 5% chance of occurring in a year, enter as 0.05). If this investment increases the likelihood of failures enter as a negative number.
What is the average duration of the outage caused by the failures? (hours)	Number	DUR	
In the case of redundant equipment, what is the duration for which the redundancy will be lost? (hours)	Number	DURR	
What is the average number of customers impacted by each failure?	Number	NCUS	

Variable Prompt	Variable Type	Variable Name	Variable Description
Enter benefit computed using method other than this questionnaire (e.g. Program Analytics)	Number	BNFT	This field is used for benefit that was computed elsewhere (i.e. not using this questionnaire)
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

The Distribution Reliability Value Measure is computed as a sequence of steps:

1. Compute the Duration of the outage
2. Compute the reduced cost of Customer Minutes of Interruption (CMI)
3. Compute Gas Distribution Reliability Benefit using outage duration and CMI
4. Take the maximum of the three computations above

9.3 Distribution Outage Recovery Benefit

Outage Recovery is calculated as value based on a combination of the impact on Customer Minutes of Interruption (CMI) and the cost of interruptions for both frequency and duration. It is similar to the Distribution Reliability benefit, however is aimed at measuring how quickly the organization can recover from an outage.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
How many customer outages per year will be shortened by this investment?	Number	OUT	If there is less than one outage per year, enter the probability of the outage as a decimal (e.g. 5% chance of occurring in a year, enter as 0.05). If this investment increases the likelihood of outages enter as a negative number.
For each of the outages what it is the expected Peak Lost Load (kVA)?	Number	PEAK	
What is the expected decrease in the duration of the outage? (hours)	Number	DUR	
Does an outage of this equipment lead to an outage to customers or is there redundancy?	Enumeration	REDU	Selection: o Customer Outage o Loss of redundancy o Loss of N-1-1 Contingency
What is the average number of customers impacted by each failure?	Number	NCUS	Enter the number of customers impacted

Variable Prompt	Variable Type	Variable Name	Variable Description
Customer Type	Enumeration	TYPE	Select "Residential" if it is unclear what the customer type is. Selection: o Primarily Residential (< 15% Commercial) o Mixed Residential / Commercial o Primarily Commercial (> 60% Commercial) o Critical Public Service (Hospital)
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

The Outage Recovery Value Measure is computed as a sequence of steps.

1. Compute the Duration of the outage
2. Compute the reduced cost of Customer Minutes of Interruption (CMI)
3. Compute the decrease in Duration Cost
4. Compute Outage Recovery Cost savings by taking the maximum of customer cost of:
    - Interrupted Power (CMI Cost)
    - Interruption Duration (Duration Cost)

9.4 Electrical Delivery Capacity Risk

Electrical Delivery capacity risk is used when a failure or event will threaten the organization's ability to deliver power to all customers according to tariff. Note that this risk type relates to delivery of power once generated and should NOT be used to capture risks related to insufficient generation.

The following types of risk would typically fall under this category:

- Overloading of transmission or distribution circuits
- Lack of required redundancy in transmission or distribution circuits (classed as "Exceeding planning limits")
- Events that lead to an under-voltage situation for some customers

9.5 Gas Delivery Capacity Risk

Gas Delivery capacity risk is similar to the Electric Delivery Capacity risk only it has fewer consequence level due to the nature of the gas distribution system. Gas Delivery capacity risk is used when a failure or event will threaten the organization's ability to deliver gas to customers.

The following types of risk would typically fall under this category:

- Inability to provide gas to new customers
- Overloading the gas distribution lines however able to supply load (classed as “Exceeding planning limits”)

9.6 Blackstart Delay Risk

If equipment is required to perform a blackstart (in the case of a grid-wide outage) and if the equipment fails then the consequence of such equipment failing is based on the increase in time it would take to perform the blackstart using the next contingency. The value of this delay is computed in 5.3.11 Blackstart Delay Cost as $60M per hour and this value is used to calibrate the consequence scale in the risk matrix.

9.7 Transmission Reliability Risk

Transmission Reliability Risk is computed based on the cost of an outage to elements of the transmission system. The consequence of this risk is determined based on the Customer Value of Δ EUE (estimated unserved energy). Δ EUE is described in the following supporting document: Manitoba Hydro T Stage 1 Recommendations_Test Report v4.pdf. The consequence is computed by multiplying Δ EUE by the duration cost of an outage for a specific customer type.

9.8 Import Transfer Capacity Risk

Import Transfer Capacity risk measures the risk of being unable to serve customers due to transmission equipment being unavailable. The risk consequence is computed by determining the expected amount of unserved energy in kWh on imports and using the average cost of unserved energy.

i.e. Import Transfer Capacity Risk =

Expected amount of unserved energy (kWh) * Cost of Energy for Mixed Customer type

10. Value Measures: Environmental

10.1 Environmental Benefit

Environmental Benefit is used to measure environmental improvements such value of CO2 emission reduction and energy efficiency (MWh) savings. It is computed in dollars and then calibrated to the Value Measure scale by dividing by 1,000.

The project owner specifies the benefits by answering the following questions:

Variable Prompt	Variable Type	Variable Name	Variable Description
Quantity of CO2 emissions that will be reduced each year? (tonnes)	Number	EMMI	Enter the number of tonnes of emission reduced
If investment is completed, energy expected to be saved per year (e.g. Line losses, reduced consumption)? (MWh)	Number	ENGY	Enter energy saved (e.g. MWh)
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%

Variable Prompt	Variable Type	Variable Name	Variable Description
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

10.2 Environmental Risk

Environmental risk is assessed based on the cost of remediation efforts to reverse any damage potentially caused. Damage so severe as not to be reversible is ranked using the most severe consequence classification.

11. Value Measures: Safety

11.1 Safety Risk

The organization does not purposefully expose employees or the general public to known safety hazards. Typically, when a safety issue is identified, an operational workaround is identified to avoid the hazard (e.g.: a limited access zone or a requirement to de-energize equipment before performing certain operations). The value of the capital investment that provides a permanent solution is to avoid the cost (in either dollars or customer minutes of interruption) of the workaround.

If a significant safety risk that could lead to serious injury or death has been identified then that risk must be mitigated either by a capital investment, an O&M investment or some kind of operating restriction. If no operating restriction is possible to mitigate the risk and the only way to address the safety risk is by a capital investment then that investment should be considered mandatory. Multiple alternatives may be created to represent multiple approaches to mitigating the risk on a temporary or permanent basis.

11.2 Security Risk

Security risk is used to capture the possibility of loss or damage due to a breach of physical or cyber security. The risk consequence is valued according to the magnitude of the loss or damage expected to result from a breach. In the case of on-going breaches, an average annual value should be used.

12. Value Measures: Corporate Citizenship

12.1 Public Perception Risk

Public Perception risk represents the risk that a failure or event will cause the organization's customers or other external stakeholders to lose confidence in the organization.

Because it is difficult to directly assess public perception, the level of consequence is assessed based on the amount of negative media coverage expected if the event or failure occurs.

12.2 Compliance Risk

Compliance risk is used to capture the impact of an event or a failure which would cause the organization to breach a federal or provincial law, a regulatory mandate or an internal policy.

In most circumstances where there has been a breach of a federal or provincial law, the consequence is a fine falling within a stipulated range. The cost to the organization, firstly, will be the amount of the fine. For a first offence, the fines levied will usually be at the lower end of the stipulated range. Most of the federal and provincial laws that are applicable to the organization's operations provide for maximum fines for a first offence of $300,000.00 or less. Where the organization is also a Crown corporation whose operations touch the lives of most of the citizens of the Province and whose policies promote adherence to the highest standards, the cost of a breach ought to include some allowance for the criticism and adverse publicity that would certainly accompany a finding of guilt for breach of a federal or provincial law. Accordingly, where the compliance risk involves the potential for a first offence, it should be assessed as being in the $1,000,000.00 range.

Where the breach of a federal or provincial law is a second or third offence, the consequence will almost certainly be a larger fine. Some statutes provide for the doubling of the maximum amount. On a second or third offence, the cost to the organization will in many circumstances be the amount of the fine. The accompanying criticism will inevitably be even greater given that the organization obviously did not correct its operations satisfactorily following the first conviction. Accordingly, in these circumstances it is appropriate to assess the compliance risk to a category that will capture the highest of likely fines, something greater than $300,000.00 and up to as much as $2.0 Million, and allow for some additional amount attributable to the heightened disapproval of the organization and its leadership.

In certain cases, a breach of a federal or provincial law can result in not only a fine but the sentencing of a director or senior officer of the organization to a term of imprisonment, usually specified to be up to one to three years, depending on the particular law that has been breached. These circumstances would constitute the most serious of compliance failures and an additional allowance should be made to reflect that the cost to the organization will not be limited to the cost of any fines but also to the embarrassment and condemnation that would accompany the sentencing of a director or senior officer. One could anticipate in these circumstances the likelihood of some sort of public review or enquiry, with its attendant costs, and probably the introduction of new operating restrictions intended to prevent similar occurrences from happening again. A consequence in the high range of $30,000,000.00 would be appropriate for these albeit rare circumstances.

Failure to conform to an internal policy is evaluated as a minor consequence.

12.3 Customer Service Benefit

Customer Service benefit is intended to gauge customer satisfaction with the service they receive from the organization. The benefit is calculated by estimating the positive impact of the project on the next utility survey.

Variable Prompt	Variable Type	Variable Name	Variable Description
What is the expected impact of this project on the percentage of customers answering satisfied or very satisfied on the next utility survey?	Enumeration	SURV	Selection: o Positive impact of 5% or more percentage points o Positive impact of 4% o Positive impact of 3% o Positive impact of 2% o Positive impact of 1% o Positive impact of < 1% o No measurable impact o No impact
What is the probability of this benefit being achieved?	Number	PROB	Enter percentage as follows: 15 for 15%
Provide any rationale or assumptions for the numbers provided.	Text	TEXT	

DOC 10

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Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States

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January 2015

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Disclaimer

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Abstract

This report updates the 2009 meta-analysis that provides estimates of the value of service reliability for electricity customers in the United States (U.S.). The meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. This report focuses on the backwards stepwise selection process that was used to develop the final revised model for all customer classes. Across customer classes, the revised customer interruption cost model has improved significantly because it incorporates more data and does not include the many extraneous variables that were in the original specification from the 2009 meta-analysis. The backwards stepwise selection process led to a more parsimonious model that only included key variables, while still achieving comparable out-of-sample predictive performance. In turn, users of interruption cost estimation tools such as the Interruption Cost Estimate (ICE) Calculator will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome. The upcoming new version of the ICE Calculator is anticipated to be released in 2015.

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List of Figures and Tables

Acronyms and Abbreviations

AIC	Akaike's Information Criterion
C&I	Commercial and Industrial
GLM	Generalized Linear Model
ICE	Interruption Cost Estimate
MAE	Mean Absolute Error
OLS	Ordinary Least Squares
RMSE	Root Mean Square Error

Executive Summary

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[1] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[2] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

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[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

Updated Interruption Cost Estimates

For each customer class, Table ES-1 provides the three key metrics that are most useful for planning purposes. These metrics are:

- Cost per event (cost for an individual interruption for a typical customer[3]);
- Cost per average kW (cost per event normalized by average demand); and
- Cost per unserved kWh (cost per event normalized by the expected amount of unserved kWh for each interruption duration).

Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

In general, even though the econometric model has been considerably simplified, it produces similar estimates to those of the 2009 model. As in the 2009 study, medium and large C&I customers have the highest interruption costs, but when normalized by average kW, interruption costs are highest in the small C&I customer class. On both an absolute and normalized basis, residential customers experience the lowest costs as a result of a power interruption.

Table ES-1: Estimated Interruption Cost per Event, Average kW and Unserved kWh (U.S.2013$) by Duration and Customer Class

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Table ES-2 shows how customer interruption costs vary by season and time of day, based on the key drivers of interruption costs that were identified in the model selection process. For medium and large C&I customers, interruption costs only meaningfully vary by season (summer vs. non-summer). For medium and large C&I customers, the cost of a summer power interruption is

[3] The interruption costs in Table ES- 1 are for the average-sized customer in the meta-database. The average annual kWh usages for the respondents in the meta-database are 7,140,501 kWh for medium and large C&I customers, 19,214 kWh for small C&I customers and 13,351 kWh for residential customers.

around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). For small C&I customers, the seasonal pattern is the opposite, with the cost of summer power interruptions lower by around 9% to 30%, depending on duration, season, and time of day. Small C&I interruption costs also vary by time of day, with the highest costs in the afternoon and morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. For residential customers, interruption costs are generally higher during the summer and in the morning and night (10 PM to 12 noon). The table also includes a weighted-average interruption cost estimate (equal to the cost per event estimates in Table ES-1), which is weighted by the proportion of hours of the year that each interruption scenario represents, depending on season and time of day. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known and accounted for in the analysis.

Table ES-2: Estimated Customer Interruption Costs (U.S.2013$) by Duration, Timing of Interruption and Customer Class

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I							
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		*$12,952*	*$15,241*	*$17,804*	*$39,458*	*$84,083*	*$165,482*
Small C&I							
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		*$412*	*$520*	*$647*	*$1,880*	*$4,690*	*$9,055*
Residential							
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		*$3.9*	*$4.5*	*$5.1*	*$9.5*	*$17.2*	*$32.4*

Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section and in more detail in Section 6. These limitations are:

- Certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs;
- There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region;
- A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes;
- Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method; and
- Finally, although the revised model is able to estimate costs for interruptions lasting longer than eight hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[4] These factors are not captured in this meta-analysis.

[4] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

1. Introduction

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[5] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[6] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new

[5] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[6] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

1.1 Recent Interruption Cost Studies

Since conducting the meta-analysis in 2009, there have been two large interruption cost surveys in the U.S., one in the southeast and another in the west. The 2011 study in the southeast involved a systemwide interruption cost survey of over 3,300 residential and small/medium business customers and nearly 100 in-person interviews of large business customers. The 2012 study in the west involved a systemwide interruption cost survey of nearly 2,700 residential and small/medium business customers and 210 in-person interviews of large business customers. Although the basic survey methodology is similar to previous work, the 2012 interruption cost study in the west featured several noteworthy methodological improvements. In particular, a dynamic survey instrument design for that study produced interruption cost estimates from 5 minutes to 24 hours, for weekdays and weekends and across many different times of the day (morning, afternoon, evening and night). As such, incorporating the 2012 data and re-estimating the underlying econometric models will enable the ICE Calculator to estimate costs for interruptions lasting longer than 8 hours, which will address one of the improvements above.

Table 1-1 provides an updated inventory of interruption cost studies that are included in the meta-dataset. The number of observations for each study is provided along with the minimum and maximum duration of power interruption scenarios in each study. Altogether, the meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012, totaling over 105,000 observations.[7] Some of the utilities surveyed all three customer types – medium and large commercial and industrial (C&I), small C&I, and residential – while others did not. In some cases there was only one dataset for C&I customers, in which case they were sorted into medium and large C&I or small C&I according to electricity usage. The split between small C&I and medium/large C&I is at 50,000 annual kWh. In total, the meta-dataset includes 44,328 observations for medium and large C&I customers, 27,751 observations for small C&I customers and 34,212 observations for residential customers. Each observation corresponds to a response for a single power interruption scenario. The surveys usually included four to six power interruption scenarios.

Table 1-1: Updated Inventory of Interruption Cost Studies in the Meta-dataset

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
Southeast-1	1997	90			0	1
Southeast-2	1993	3,926	1,559	3,107	0	4
	1997	3,055	2,787	3,608	0	12
Southeast-3	1990	2,095	765		0.5	4

[7] To the knowledge of the authors, this dataset includes nearly all large power interruption cost studies that have been conducted in the US. Some studies may not have been included for data confidentiality reasons.

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
	2011	7,941	2,480	3,969	1	8
Midwest-1	2002	3,171			0	8
Midwest-2	1996	1,956	206		0	4
West-1	2000	2,379	3,236	3,137	1	8
West-2	1989	2,025	5		0	4
	1993	1,790	825	2,005	0	4
	2005	3,052	3,223	4,257	0	8
	2012	5,342	4,632	4,106	0	24
Southwest	2000	3,991	2,247	3,598	0	4
Northwest-1	1989	2,210		2,126	0.25	8
Northwest-2	1999	7,091		4,299	0	12

= Recently incorporated data

Prior to adding the 2012 West-2 survey, the meta-dataset included power interruption scenarios with durations of up to 12 hours. However, the 2009 model for each customer class estimated interruption costs that reached a maximum at 8 hours, and then the estimated interruption costs would decrease, which indicated that the prior model clearly did not provide reliable predictions beyond 8 hours (i.e., it is unreasonable that a 9-hour power interruption would cost less than an 8-hour one). As discussed in Sections 3 through 5, for interruptions from 8 to 16 hours, the new model produces estimates that are more reasonable and show gradually increasing costs up to 16 hours. This improvement in model performance is attributed to the addition of the 24-hour interruption scenarios (2012 West-2) and to the much simpler model specification that resulted from the rigorous selection process.

Although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[8] These factors are not captured in this meta-analysis.

[8] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

As discussed in Section 6, another caveat is that this meta-analysis may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and "cloud" computing, which may have led to an increase in interruption costs for both producers and consumers of these services. Therefore, the outdated vintage of the data presents concerns that underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

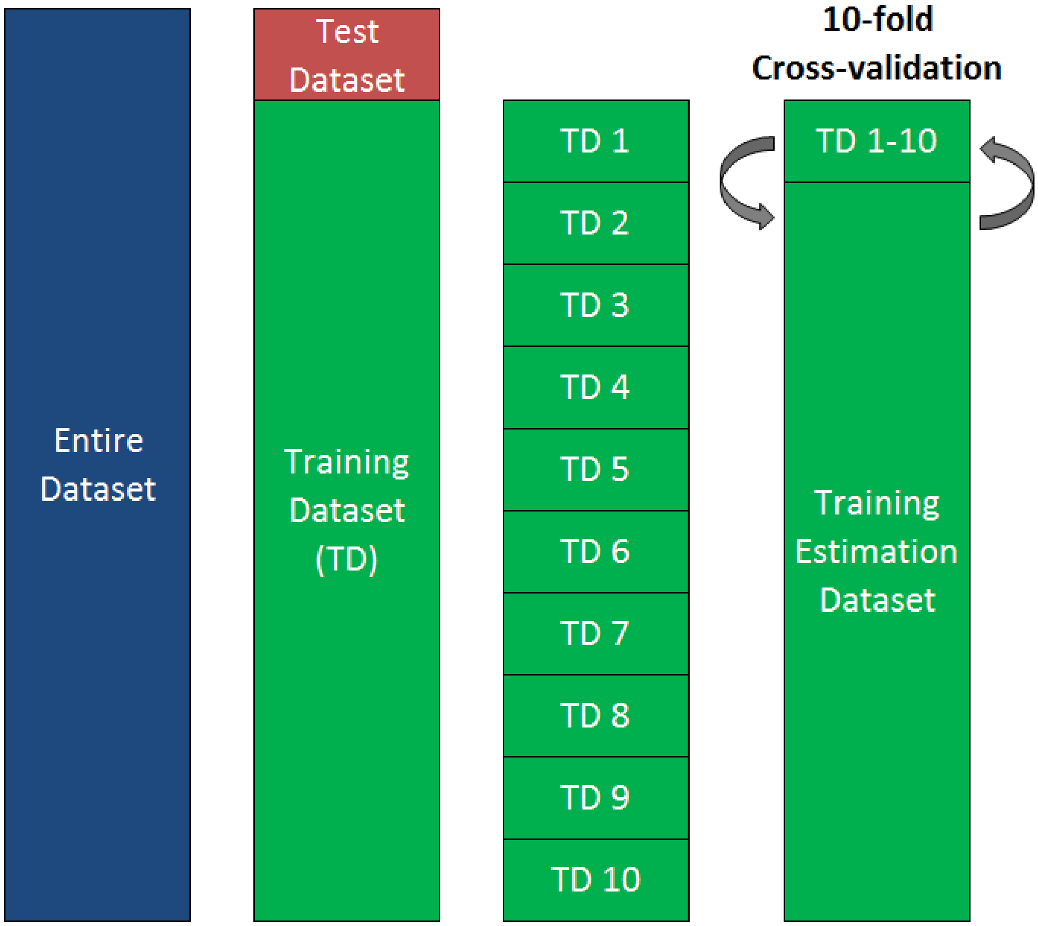
1.2 Re-estimating Econometric Models

Using the new meta-dataset, Nexant re-estimated the econometric models that relate interruption costs to duration, customer characteristics such as annual kWh, and other factors. Nexant then compared the results of the original model specification to those of several alternatives that included a reduced number of variables. This model selection process addressed another ICE Calculator improvement – reducing the amount of detailed customer characteristics information that ICE Calculator users must provide, which has been a significant barrier to the tool's use. When the econometric models were originally estimated in 2009, statistical significance was the focus of the analysis and, due to the large number of observations in the meta-dataset, many of the customer characteristics variables were statistically significant in the model, even if the marginal effect of the variable was negligible and/or collinear with other variables. Basically, many of the variables in the original specification were statistically significant, but not practically significant. In re-estimating the models, Nexant focused on the practical significance of each variable by conducting sensitivity tests to determine which variables have a substantive impact on the interruption cost estimates. Nexant also employed more recent model selection methods that have been developed since 2009, which significantly improved the rigor with which variables were selected for the model. This process led to a more parsimonious model that only included key variables. In turn, ICE Calculator users will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome.

1.3 Overview of Model Selection Process

Figure 1-1 provides an overview of the model selection process. The entire dataset of interruption cost estimates for each customer class is first randomly divided into a test dataset (10% of the entire dataset) and a training dataset (the remaining 90%). The training dataset is used to train the model, which refers to the process of selecting variables for the final specification. The test dataset is excluded from the model training process so that it can be used as a test of the final model performance on unseen data, which refers to data that is completely separate from the model training process. Next, the training dataset is randomly divided into 10 equally sized parts. Then, each candidate model specification is estimated on nine of 10 parts of the training dataset. The estimated coefficients for each candidate model specification are subsequently used to predict interruption costs on the tenth part of the training dataset. This process, which is referred to as 10-fold cross-validation, is repeated nine times while withholding one of the remaining nine parts of the training dataset each time. Relevant accuracy metrics for each model specification are computed for each of the 10 parts of the training dataset. Those accuracy metrics are ranked to determine the final model specification through a backwards stepwise selection process. Next, the final model specification is run on the entire training dataset and the estimated coefficients are used to predict interruption costs for the test dataset. Relevant accuracy metrics for the test dataset are also computed. If model performance on the test dataset is similar, the final specification is then estimated on the entire dataset and those estimated coefficients make up the final model. This process is conducted for each of the three customer classes separately.

Figure 1-1: Overview of Model Selection Process



1.4 Variable Definitions and Units

There are many variables that are common among customer classes, so all variable definitions and units are provided in this section. Table 1-2 provides the units and definitions of variables that are used in the models for all customer classes.

Table 1-2: Units and Definitions of Variables for All Customer Classes

Variable Name	Variable Definition	Units
annual MWh	Annual MWh of customer	MWh
duration	Duration of power interruption scenario	Minutes
time of day	Time of day of power interruption scenario	Categorical – Morning (6 AM to 12 PM); Afternoon (12 to 5 PM; Evening (5 to 10 PM); Night (10 PM to 6 AM)
weekday	Time of week of power interruption scenario	Binary – Weekday = 1; Weekend = 0
summer	Time of year of power interruption scenario	Binary – Summer = 1; Non-summer = 0
warning	Whether power interruption scenario had advance warning	Binary – Warning = 1; No warning = 0

Table 1-3 provides the units and definitions of variables that are used in the models for both the small and medium/large C&I customer classes. For both C&I customer classes, the model selection process begins with separate variables for all eight of the industry groups in the table, with Agriculture, Forestry & Fishing as the reference category by default. However, given that each industry group is tested separately for inclusion in the model, only one or two industry variables may remain in the final model, in which case the dropped industry variables are relegated to the reference category. Within the reference category, there may be multiple industries with presumably varying interruption costs, but if the model selection process has shown that there are not any meaningful differences within the industries in the reference category, those industry variables will be grouped together. The same logic applies for other categorical variables.

Table 1-3: Units and Definitions of Variables for C&I Customers

Variable Name	Variable Definition	Units
industry	Customer business type, based on NAICS or SIC code	Categorical – Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
backup equipment	Presence of backup equipment at facility	Categorical – None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

Finally, Table 1-4 provides the units and definitions of variables that are only used in the residential customer models.

Table 1-4: Units and Definitions of Variables for Residential Customers

Variable Name	Variable Definition	Units
household income	Household income	$
medical equip.	Presence of medical equipment in home	Binary – Medical equipment = 1; No medical equipment = 0
backup generation	Presence of backup generation in home	Binary – Backup = 1; No backup = 0
outage in last 12 months	Interruption of longer than 5 minutes within past year	Binary – Yes = 1; No = 0
# residents X-Y	Number of residents in home within X-Y age range	Number of people
housing	Type of housing	Categorical – Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

1.5 Report Organization

The remainder of this report proceeds as follows. Section 2 summarizes the regression modeling methodology and selection process that applies to all three customer classes – medium and large C&I, small C&I and residential. This is followed by three sections that describe the final model selection and provide the final regression coefficients for each customer class. Finally, Section 6 describes some of the study's limitations.

2. Methodology

This section summarizes the study methodology, including the regression model structure and selection process.

2.1 Model Structure

A two-part regression model was used to estimate the customer interruption cost functions (also referred to as customer damage functions). This is the same class of model used in the previous meta-study. The two-part model assumes that the zero values in the distribution of interruption costs are correctly observed zero values, rather than censored values. In the first step, a probit model is used to predict the probability that a particular customer will report any positive value versus a value of zero for a particular interruption scenario. This model is based on a set of independent variables that describe the nature of the interruption as well as customer characteristics. The predicted probabilities from this first stage are retained. In the second step, using a generalized linear model (GLM), interruption costs for only those customers who report positive costs are related to the same set of independent variables used in the first stage. Predictions are made from this model for all observations, including those with a reported interruption cost of zero. Finally, the predicted probabilities from the first part are multiplied by the estimated interruption costs from the second part to generate the final interruption cost predictions.

The functional form for the second part of the two-part model must take into account that the interruption cost distribution is bounded at zero and extremely right skewed (i.e. it has a long tail in the upper end of the distribution). Ordinary least squares (OLS) is not an appropriate functional form given these conditions. A simple way to define the customer damage function given the above constraints is to estimate the mean interruption cost, which is linked to the predictor variables through a logarithmic link function using a GLM.

The parameter values in the two-part model cannot be directly interpreted in terms of their influence on interruption costs because the relationships are among the variables in their logarithms. However, the estimated model produces a predicted interruption cost, given the values of variables in the models. To analyze the magnitude of the impact of variables in the model on interruption cost, it is necessary to compare the predictions made by the function under varying assumptions. For example, it is possible to observe the effect of duration on interruption cost by holding the other variables constant at their sample means. In this way one can predict average customer interruption costs of varying durations holding other factors constant statistically.

For a more detailed discussion of the two-part model, its functional form and the reasons why it is most appropriate for this type of data, refer to the methodology section of the 2009 report.

2.2 Summary of Model Selection Process

Nexant aimed to estimate a more parsimonious model that only included key predictor variables. This facilitates interruption cost estimation by simplifying the ICE Calculator interface and reducing the burden that ICE Calculator users face in providing numerous, accurate customer characteristics information. This section first outlines the steps involved in the model selection process that Nexant undertook, followed by a more detailed exposition of the problem at hand, and a justification for the method.

To select a more parsimonious model, Nexant conducted the following steps for each of the three customer classes:

1. Randomly sample 10% of the data and hold it out as the test dataset (assign other 90% as the training dataset);
2. Split training dataset into 10 randomly assigned, equally sized parts;
3. Start with the original specification (the global model) and identify model variables that are candidates for removal (all variables except ineligible lower power terms);
4. Remove one of the eligible model variables to yield a new model;
5. Estimate model on nine of 10 parts of the training dataset and retain estimates;
6. Use retained estimates from step 5 to predict on the tenth part of the training dataset, computing relevant accuracy metrics;
7. Repeat steps 5 and 6, cycling over each of the remaining 9 parts of the training dataset;
8. Take the average and standard deviation of the accuracy metrics from the predictions for each of 10 parts of the training dataset;
9. Repeat steps 4 through 8, for each possible candidate variable for removal;
10. Use saved accuracy metrics to rank models;
11. Exclude from the global model the variable, which when dropped, produced estimates that outperformed the rest;
12. Repeat steps 2 through 11 until only a constant remains;
13. Inspect results and select model that is parsimonious, yet sufficiently accurate according to the out-of-sample accuracy metrics described above; and
14. Test final model against the original global model using the test dataset to estimate model's performance on unseen data (ensures that the model predicts well for data that was not included in the model training process).

As discussed in Section 1, this model selection process draws from the recent model selection methods that have been developed since 2009,[9] which significantly improves the rigor with which variables are selected for the model. The remainder of this section describes this process in more detail.

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[9] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

2.3 Details of Model Selection Process

A model selection problem involves choosing a statistical model from a set of candidate models, given some data. In this case, the data were the pre-existing set of interruption cost surveys for each customer class. Nexant selected a candidate set of models that included the original model specification from the 2009 study, henceforth referred to as the global model, as well as all models that were nested in the global model, that is to say all models that occur when removing one of more predictor variables from the global model. This candidate set is appropriate for several reasons. First of all, nearly all of the variables that were available in the meta-dataset were already included in the global model. Secondly, all the variables in the global model are plausibly related to interruption costs, and are not simply spuriously correlated. For example, it is reasonable to conclude that a resident with medical equipment that requires a power supply would be willing to pay more to avoid a power interruption than a resident without such medical equipment. Similar conclusions can be made for the other predictor variables in the global model, across sectors, making all of them viable to include in candidate models. Furthermore, to introduce candidate models that feature predictors not already included in the global model, such as new characteristics or higher power terms, would make the task of selecting a more parsimonious model significantly more challenging. Adding new predictors to candidate models not only increases the complexity of those candidate models, but the number of candidate models increases exponentially, making selecting among them computationally challenging.[10] It therefore makes practical sense to limit the predictors used in candidate models to those used in the global model. Also in the interest of simplifying the selection process, Nexant restricted the specifications of the probit and GLM models to be identical. This was the same form that the original regression model took.

Nexant developed an iterative process to choose among the candidate set of models. This is a backwards stepwise selection method that parses down the global model one variable at a time. At each step of the process, a variable is removed from the prior model (the global model in the first step) and the resulting model is evaluated in out-of-sample tests using a variety of metrics. This is performed for all possible variables that can be excluded, and the model that performs best on average across the various metrics is retained, or rather its exclusion is retained, and becomes the prior model in the next step of the process. (Alternatively, one can consider the excluded variable as that which diminished the performance of the global model the least, relative to the other possible exclusions, although it was often the case that the performance improved.) The outcome at each step is carefully examined to determine whether an acceptably parsimonious model has been selected, and whether excluding a particular variable will severely diminish the model's predictive power, in which case that variable is retained in the final model.

The selection process uses rigorous out-of-sample testing to evaluate the performance of various models and ensure that the final model is not over-fitted.[11] Nexant divided the sample into a training dataset, used to fit models; a validation dataset, used to compare models; and a test

[10] It can be shown that a global model with n predictors has $2^n - 1$ possible nested models. Furthermore, when m new predictors are added to the global model, the number of possible nested models increases by $(2^m - 1)2^n$.

[11] Over-fitting occurs when a model describes random variation in the data. The problem manifests itself through good predictive performance on the fitted data, but poor predictive performance on unseen data that the model was not fitted to.

dataset, used as a final independent test to show how well the selected model will generalize to unseen data. The test dataset comprised 10% of the sample, and was "held out" throughout the model fitting and selection process. At each step of the selection process, the models were compared using 10-fold cross-validation. Ten-fold cross-validation divides the remaining sample data into ten equal size subsamples. Nine of those subsamples are used as the training dataset to fit the model, and the tenth is used to validate the performance of that fitted model and choose among models. This process is repeated ten times with each of the subsamples used once to validate the fitted model. This method reduces the likelihood of over-fitting the model by using unseen data in the validation step; models that generalize well to new data will be selected over those that do not. Furthermore, by "folding" the data and iterating over subsamples, each observation is used exactly once in the validation step, so all of the available data (other than the 10% in the test dataset) are used to select models.

Rather than rely on a single metric to select a model, Nexant computed several metrics, ranked models by each of these metrics, then averaged the ranks to give an overall rank across metrics. Root-mean-square error (RMSE), mean absolute error (MAE), and the coefficient of determination (R-squared) are computed in out-of-sample tests. RMSE measures the average prediction error of a model. The differences between observed and predicted values are computed, squared, and then averaged before the square root is taken to correct the units. Because errors are squared before the average, RMSE penalizes larger errors more than smaller errors. MAE also measures the average prediction error of a model. The differences between observed and predicted values are computed, their absolute value is taken, and then the absolute errors are averaged. Errors of every magnitude are penalized equally. In the case of both RMSE and MAE, values range from zero to infinity, and smaller values are preferred. R-squared measures the fraction of variation of the dependent variable that is explained by a model. Its values range from 0 to 1, and a larger value is preferred. At each step, an information theoretic approach is also used to produce a fourth ranking of models that is incorporated into the average. This ranking uses Akaike's Information Criterion (AIC), which is an estimate of the expected, relative distance between the fitted model and the unknown true mechanism that generated the observed data. It is a measure of the information that is lost when a model is used to approximate the true mechanism. A thorough exposition of the relative advantages and disadvantages of these different metrics is beyond the scope of this report. That said, by averaging the ranks obtained from each metric and choosing an overall winner, Nexant does not prioritize minimizing one kind of error over another, but rather adopts a holistic approach.

3. Medium and Large C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for medium and large C&I customers, which are C&I customers with annual usage of 50,000 kWh or above.

3.1 Final Model Selection

The global model for medium and large C&I customers is shown below:

$$\begin{aligned}&\mathit{Interruption\ Cost}\\&= f\big(\ln(\mathit{annual\ MWH}), \mathit{duration}, \mathit{duration}^2, \mathit{duration} \times \ln(\mathit{annual\ MWh}), \mathit{duration}^2\\&\times \ln(\mathit{annual\ MWh}), \mathit{weekday}, \mathit{warning}, \mathit{summer}, \mathit{industry}, \mathit{time\ of\ day}, \mathit{backup\ equipment}\big)\end{aligned}$$

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Industry, time of day and backup equipment are all categorical variables, and their respective categories are shown in Table 3-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 3-1: Breakdown of Categorical Variables Featured in Global Model – Medium and Large C&I

Variable	Categories
industry	Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
time of day	Night (10 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM)
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 3-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for medium and large C&I customers can be estimated relatively accurately with a few variables and interactions representing customer usage and interruption duration, along with binary variables for manufacturing customers and for power interruptions that occur during the summer. A few of the 15 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 3-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Medium and Large C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	116	-	29.6	-	0.143	-	-	-	-	-
1	*evening*	116	1	29.5	1	0.148	1	44.1	589	4.5	1.9
2	*weekday*	116	1	29.5	2	0.150	1	44.1	589	7.0	2.8
3	*morning*	116	1	29.5	2	0.151	1	44.3	589	9.5	3.4
4	*afternoon*	116	1	29.4	1	0.153	1	44.5	589	10.0	3.3
5	*wholesale & retail trade*	116	2	29.4	2	0.153	2	44.5	589	4.0	2.5
6	*backupgen and power conditioning*	116	1	29.4	3	0.155	1	44.6	589	8.5	3.4
7	*services*	116	1	29.4	1	0.155	1	44.7	589	8.5	2.9
8	*public administration*	116	3	29.5	2	0.155	3	44.7	589	2.5	2.6
9	*unknown*	116	1	29.5	3	0.155	1	44.7	590	3.0	2.0
10	*finance, insurance & real estate*	116	1	29.5	1	0.154	1	44.7	590	4.0	1.8
11	*transportation, communication & utilities*	116	1	29.5	2	0.154	1	44.7	591	4.5	2.1
12	*construction*	116	1	29.5	1	0.154	1	44.8	591	4.5	1.9
13	*mining*	116	1	29.5	1	0.153	1	44.8	591	2.5	1.4
14	*backupgen or power conditioning*	116	1	29.5	1	0.152	1	44.8	591	1.0	1.0
15	*warning*	116	1	29.6	1	0.148	1	44.9	592	2.5	1.4
16	*manufacturing*	117	1	29.9	2	0.137	1	45.0	595	2.5	1.6
17	*summer*	117	1	30.0	1	0.128	1	45.4	595	1.5	1.1
18	*$duration^2$ x ln(annual MWh)*	119	1	30.5	1	0.106	1	45.5	595	1.0	1.0
19	*duration x ln(annual MWh)*	120	1	30.7	1	0.096	1	45.5	595	1.0	1.0
20	*$duration^2$*	129	2	32.8	1	-0.054	2	46.2	598	1.0	1.5
21	*duration*	118	1	31.3	1	0.118	1	47.8	604	1.5	1.1
22	*ln(MWh annual)*	126	1	37.4	1	0.000	1	48.7	640	1.0	1.0

The final model for medium/large C&I customers is shown below:

$$Interruption\ Cost = f(\ln(annual\ MWH), duration, duration^2, duration \times \ln(annual\ MWh), duration^2 \times \ln(annual\ MWh), summer, industry)$$

Manufacturing is the only remaining industry category in the model. Note that as categories are removed, they are relegated to the reference category, so for example the manufacturing binary variable should now be interpreted as the average impact on interruption cost associated with being in the manufacturing industry, relative to all other industries.

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance.

The results are shown in Table 3-3. The final model outperforms the global model in each accuracy metric.

Table 3-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Medium and Large C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	111	29.6	0.118
Global	111	29.8	0.115

3.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for medium and large C&I customers. Table 3-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer usage, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions; and
- Manufacturing industry customers are more likely to incur costs than non-manufacturing industry customers.

Table 3-4: Regression Output for Probit Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.005	0.000	0.000
duration^2	-2.820E-06	0.000	0.000
summer	0.410	0.023	0.000
Customer Characteristics			
ln(annual MWh)	0.118	0.006	0.000
Interactions			
duration x ln(annual MWh)	-3.416E-04	0.000	0.000
duration^2 *x ln(annual MWh)*	1.640E-07	0.000	0.000
Industry			
manufacturing	0.200	0.025	0.000
Constant	-0.958	0.047	0.000

Table 3-5 describes the final GLM regression model, which relates the level of interruption costs to customer usage and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing industry customers incur larger costs for similar interruptions than equivalent non-manufacturing customers;
- The difference between summer and non-summer interruption costs is statistically insignificant (all other coefficients are statistically significant).

Table 3-5: Customer Regression Output for GLM Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.006	0.001	0.000
duration^2	-3.260E-06	0.000	0.000
summer	0.113	0.060	0.058
Customer Characteristics			
ln(annual MWh)	0.495	0.016	0.000
Interactions			
duration x ln(annual MWh)	-1.882E-04	0.000	0.047
duration^2 *x ln(annual MWh)*	1.480E-07	0.000	0.028
Industry			
manufacturing	0.823	0.069	0.000
Constant	5.292	0.127	0.000

Finally, Table 3-6 shows the average values of the regression inputs for medium and large C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

Table 3-6: Descriptive Statistics for Regression Inputs – Medium and Large C&I

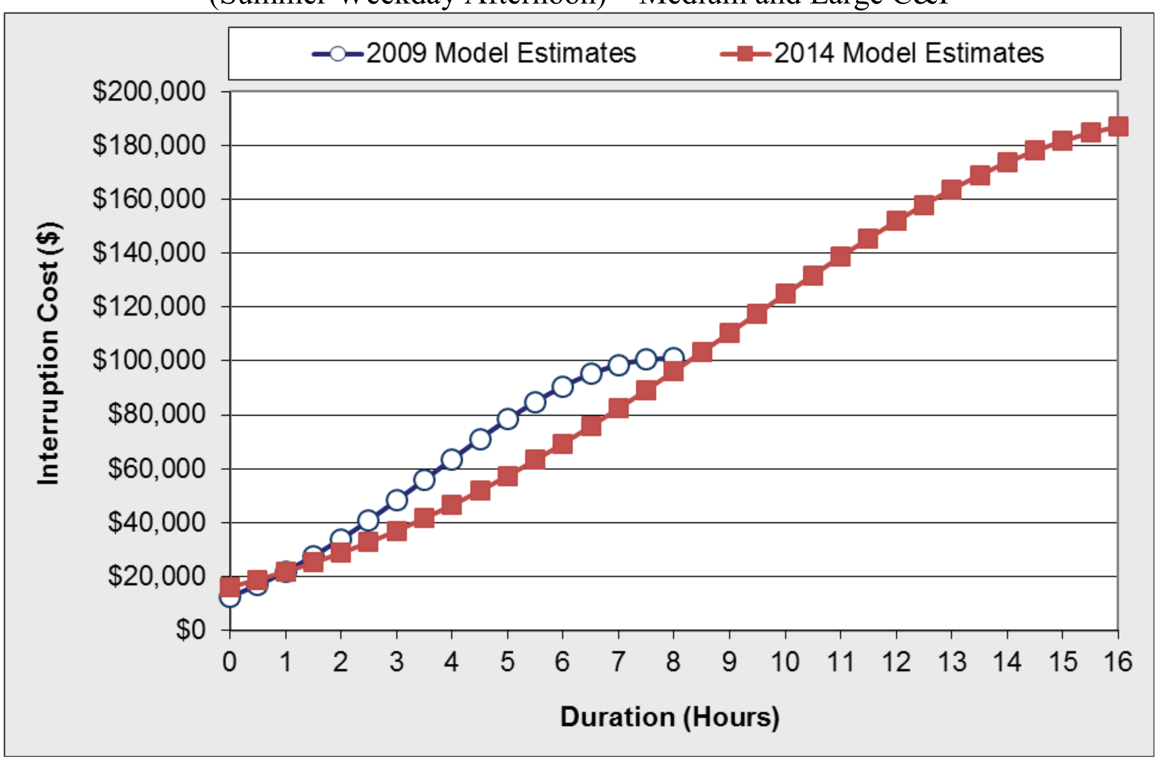
Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	44,328	162	0	60	60	240	1,440
duration^2	44,328	82,724	0	3,600	3,600	57,600	2,073,600
summer	44,328	86.5%	0%	100%	100%	100%	100%
Customer Characteristics							
ln(annual MWh)	44,328	6.6	3.9	4.9	6.2	7.9	13.9

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interactions							
duration x ln(annual MWh)	44,328	1,060	0	255	437	1,327	17,064
duration^2 x ln(annual MWh)	44,328	530,872	0	14,881	26,250	317,870	24,600,000
Industry							
manufacturing	44,328	23.3%	0%	0%	0%	0%	100%

3.3 Comparison of 2009 and 2014 Model Estimates

Figure 3-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. The magnitude of the interruption cost estimates is similar between the two models, but there is a noticeable change in the functional form, which is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 3-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Medium and Large C&I



3.4 Interruption Cost Estimates and Key Drivers

Table 3-7 shows how medium and large C&I customer interruption costs vary by season. Considering that time of day and day of week were not important factors in the model for medium and large C&I customers, the only temporal variable to consider is season (summer or non-summer). The cost of a summer power interruption is around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). Considering that the non-summer time period (October through May) accounts for two-thirds of the year, the weighted-average interruption cost estimate is closer to the non-summer estimate. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season is known.

Table 3-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Medium and Large C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		**$12,952**	**$15,241**	**$17,804**	**$39,458**	**$84,083**	**$165,482**

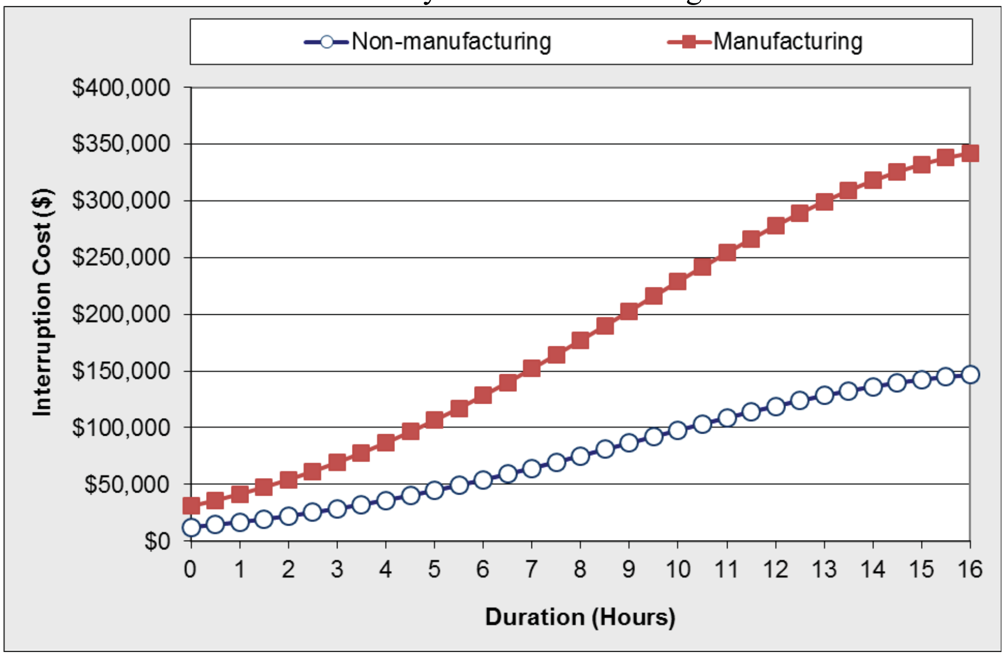
Based on the weighted-average interruption cost estimate, Table 3-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW and cost per unserved kWh for medium and large C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 3-8: Cost per Event, Average kW and Unserved kWh – Medium and Large C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7

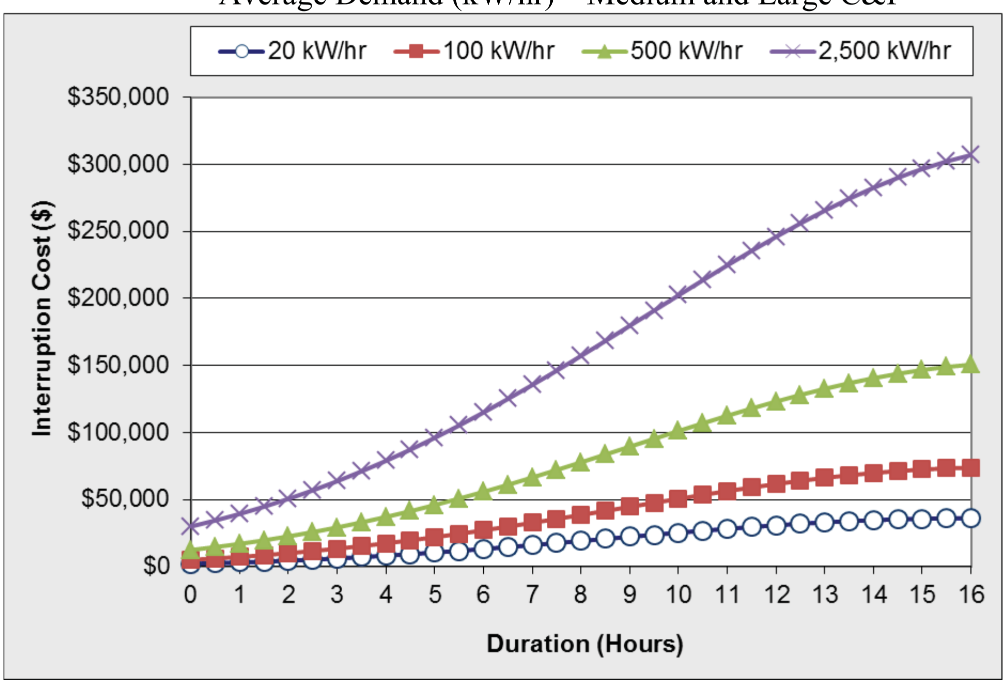
Figure 3-2 shows the medium and large C&I interruption costs in the summer for non-manufacturing and manufacturing customers. As in the 2009 model, interruption costs in the manufacturing sector are relatively high. At all durations, the estimated interruption cost for manufacturing customers is more than double the cost for non-manufacturing customers. This is a key driver to consider for planning purposes – whether the planning area of interest includes medium and large C&I customers with manufacturing facilities that may be particularly sensitive to power interruptions.

Figure 3-2: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Industry – Medium and Large C&I



Finally, Figure 3-3 shows the medium and large C&I interruption costs in the summer for various levels of average demand. As discussed above, medium and large C&I interruption costs increase at a decreasing rate as usage increases. This pattern is notable in the figure. Each increment in average demand represents a 5-fold increase in usage, but interruption costs only increase by a factor of 2.0 to 2.5 from one level of average demand to the next.

Figure 3-3: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Medium and Large C&I



4. Small C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for small C&I customers, which are C&I customers with annual usage of less than 50,000 kWh.

4.1 Final Model Selection

The global model for small C&I customers was identical to that for the medium and large C&I customers. Refer to Section 3.1 above for a discussion of the global model specification. The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 4-1 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for small C&I customers can be estimated relatively accurately with variables representing customer usage and interruption duration, along with some binary variables for customer characteristics and interruption timing. Considering how difficult it can be for ICE Calculator users to find information for some of the 12 excluded variables (especially for small C&I customers), this final model will be much easier to use.

Table 4-1: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Small C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	6.17	-	1.95	-	0.044	-	-	-	-	-
1	*transportation, comunication & utilities*	6.16	1	1.94	2	0.048	1	30.6	245	8.0	3.0
2	*mining*	6.16	1	1.94	1	0.049	1	30.6	245	7.0	2.5
3	*warning*	6.16	1	1.94	3	0.049	1	30.6	245	4.5	2.4
4	*evening*	6.16	1	1.94	2	0.049	2	30.6	245	4.0	2.3
5	*duration^2 x ln(annual MWh)*	6.16	1	1.94	3	0.049	2	30.6	245	3.0	2.3
6	*finance, insurance & real estate*	6.16	2	1.94	4	0.049	2	30.7	245	5.5	3.4
7	*unknown industry*	6.16	5	1.94	2	0.049	2	30.7	245	5.5	3.6
8	*duration x ln(annual MWh)*	6.16	3	1.94	2	0.049	2	30.7	245	1.5	2.1
9	*public administration*	6.16	2	1.94	3	0.049	4	30.7	245	2.0	2.8
10	*weekday*	6.16	2	1.94	3	0.048	3	30.7	245	3.5	2.9
11	*wholesale & retail trade*	6.16	1	1.94	1	0.049	1	30.9	245	7.5	2.6
12	*services*	6.16	2	1.94	1	0.049	3	30.9	245	2.0	2.0
13	*morning*	6.16	2	1.95	2	0.048	2	31.4	245	4.5	2.6
14	*afternoon*	6.16	1	1.95	2	0.048	1	31.5	245	3.0	1.8
15	*summer*	6.17	1	1.95	1	0.047	1	31.8	245	4.5	1.9
16	*ln(annual MWh)*	6.17	1	1.96	3	0.045	1	32.0	245	3.0	2.0
17	*backupgen and power conditioning*	6.19	2	1.97	1	0.041	1	32.1	246	2.5	1.6
18	*backupgen or power conditioning*	6.20	1	1.98	1	0.036	1	32.1	246	2.0	1.3
19	*manufacturing*	6.22	1	2.00	2	0.029	1	32.1	246	1.5	1.4
20	*construction*	6.24	1	2.01	1	0.023	1	32.2	247	1.0	1.0
21	*duration^2*	6.52	1	2.16	1	-0.089	1	32.8	248	1.0	1.0
22	*duration*	6.32	1	2.13	1	-0.001	1	34.2	251	1.0	1.0

The final model for small C&I customers is shown below:

$$Interruption\ Cost = f(\ln(annual\ MWH), duration, duration^2, summer, industry, backup\ equipment, time\ of\ day)$$

Industry, backup equipment and time of day are the only categorical variables remaining, and many of the categories were removed. Note that as categories are removed, they are relegated to the reference category, so for example the construction binary variable should now be interpreted as the average impact on interruption cost associated with being in the construction industry, relative to all industries other than manufacturing, which is the only other industry that was retained as a binary variable. The categories that remain in the final model are shown in Table 4-2 below.

Table 4-2: Breakdown of Categorical Variables Featured in Final Model – Small C&I

Variable	Categories
industry	Other; Construction; Manufacturing
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning
time of day	Other (5 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM)

To confirm that the selection process did not produce an overfitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 4-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 4-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Small C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	5.50	1.82	0.045
Global	5.49	1.82	0.048

4.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 4-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer characteristics, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions;
- Afternoon interruptions are more likely to incur costs than any other time of day; and
- Manufacturing and construction customers are more likely to incur costs than customers in other industries.

Table 4-4: Customer Regression Output for Probit Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.780E-06	0.000	0.000
summer	0.215	0.030	0.000
morning	0.537	0.022	0.000
afternoon	0.664	0.029	0.000

Variable	Coefficient	Standard Error	P-Value
Customer Characteristics			
ln(annual MWh)	0.124	0.013	0.000
backupgen or power conditioning	0.082	0.025	0.001
backupgen and power conditioning	0.272	0.059	0.000
Industry			
construction	0.261	0.054	0.000
manufacturing	0.176	0.042	0.000
Constant	-1.332	0.048	0.000

Table 4-5 describes the final GLM regression model, which relates the level of interruption costs to customer and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing and construction industry customers incur larger costs for similar interruptions than equivalent customers in other industries; and
- Summer interruptions incur lower interruption costs than other times of the year.

Table 4-5: Customer Regression Output for GLM Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.004	0.000	0.000
duration^2	-2.160E-06	0.000	0.000
summer	-0.384	0.073	0.000
morning	-0.057	0.070	0.413
afternoon	-0.032	0.083	0.701
Customer Characteristics			
ln(annual MWh)	0.069	0.035	0.046
backupgen or power conditioning	0.308	0.058	0.000
backupgen and power conditioning	0.538	0.129	0.000
Industry			
construction	0.786	0.153	0.000
manufacturing	0.587	0.104	0.000
Constant	7.000	0.135	0.000

Finally, Table 4-6 shows the average values of the regression inputs for small C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

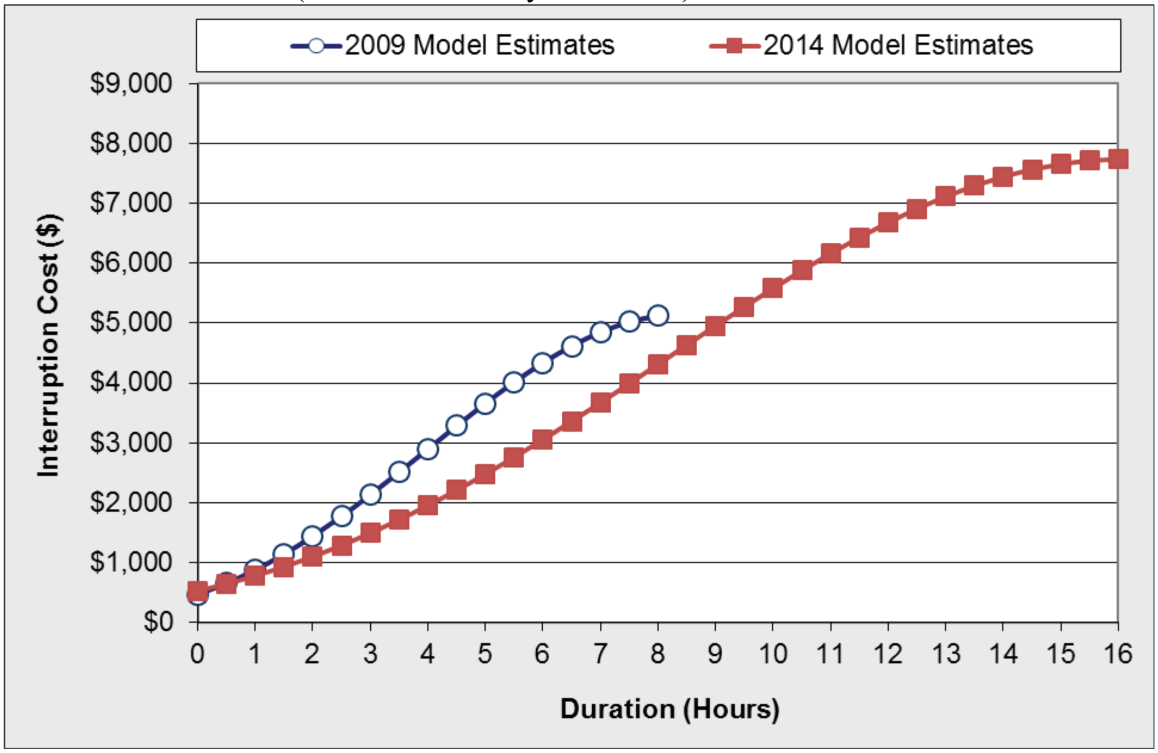
Table 4-6: Descriptive Statistics for Regression Inputs – Small C&I

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	27,751	191	0	60	60	240	1,440
duration^2	27,751	107,425	0	3,600	3,600	57,600	2,073,600
summer	27,751	89.3%	0%	100%	100%	100%	100%
morning	27,751	45.5%	0%	0%	0%	100%	100%
afternoon	27,751	37.6%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	27,751	2.6	-2.0	2.2	2.8	3.3	3.9
backupgen or power conditioning	27,751	27.1%	0%	0%	0%	100%	100%
backupgen and power conditioning	27,751	3.5%	0%	0%	0%	0%	100%
Industry							
construction	27,751	4.6%	0%	0%	0%	0%	100%
manufacturing	27,751	7.8%	0%	0%	0%	0%	100%

4.3 Comparison of 2009 and 2014 Model Estimates

Figure 4-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with medium and large C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 4-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Small C&I



4.4 Interruption Cost Estimates and Key Drivers

Table 4-7 shows how small C&I customer interruption costs vary by season and time of day. The cost of a summer power interruption is around 9% to 30% lower than a non-summer one, depending on duration, season, and time of day. Interestingly, this is opposite the pattern of medium and large C&I customers, which experience higher interruption costs during the summer. As for how interruption costs vary by time of day, costs are highest in the afternoon and are similarly high in the morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. Considering that the evening/night time period (5 PM to 6 AM) accounts for a majority of the hours of the day, the weighted-average interruption cost estimate is closer to the evening/night estimates. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 4-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Small C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		**$412**	**$520**	**$647**	**$1,880**	**$4,690**	**$9,055**

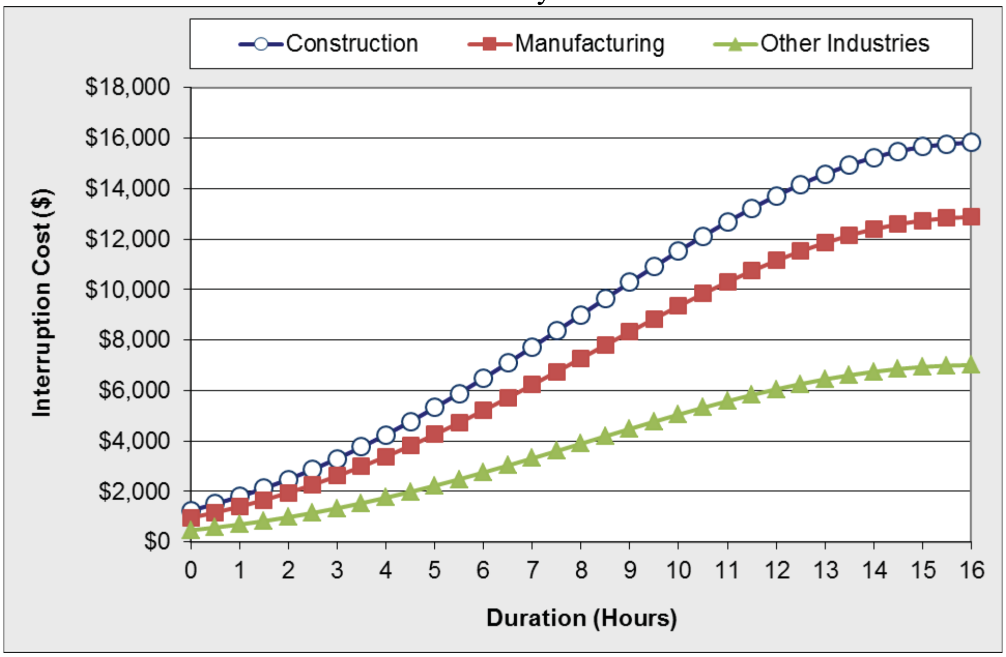
Based on the weighted-average interruption cost estimate, Table 4-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for small C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 4-8: Cost per Event, Average kW and Unserved kWh – Small C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0

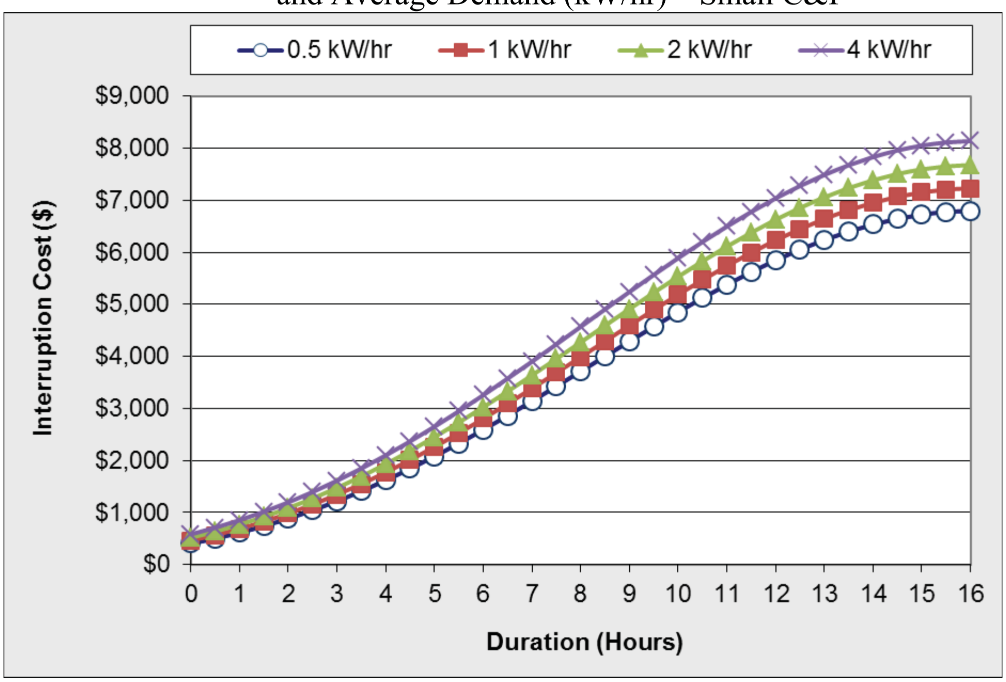
Figure 4-2 shows the small C&I interruption costs in the summer afternoon by industry. As in the 2009 model, interruption costs in the manufacturing and construction sectors are relatively high. At all durations, the estimated interruption cost for manufacturing and construction customers is around double or more the cost for customers in other industries. As in the medium and large C&I customer class, this is a key driver to consider for planning purposes – whether the planning area of interest includes small C&I customers with manufacturing or construction facilities that may be particularly sensitive to power interruptions.

Figure 4-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Industry – Small C&I



Finally, Figure 4-3 shows the small C&I interruption costs in the summer afternoon for various levels of average demand. Small C&I interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 10% from one level of average demand to the next.

Figure 4-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Small C&I



5. Residential Results

This section summarizes the results of the model selection process and provides the model coefficients for residential customers.

5.1 Final Model Selection

The global model for residential customers is shown below:

Interruption Cost = f(ln(annual MWh), duration, duration², household income, medical equip., backup generation, summer, weekday, outage in last 12 months, # residents 0-6, # residents 7-18, # residents 19-24, # residents 25-49, # residents 50-64, # residents over 64, time of day, housing)

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Time of day and housing are categorical variables, and their respective categories are shown in Table 5-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 5-1: Breakdown of Categorical Variables Featured in Global Model – Residential

Variable	Categories
time of day	Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM); Late Evening/Early Morning
housing	Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 5-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for residential customers can be estimated relatively accurately with variables representing customer usage, household income, and interruption duration, along with some binary variables for interruption timing. A few of the 16 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 5-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Residential

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value	Rank	Value	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	16.6	-	8.50	-	0.145	-	-	-	-	-
1	*late evening/early morning*	16.5	1	8.49	1	0.147	1	37.3	126	9.5	3.1
2	*mobile housing*	16.5	3	8.48	2	0.148	3	37.3	126	3.5	2.9
3	*outage in last 12 months*	16.5	1	8.48	1	0.149	1	37.3	126	9.5	3.1
4	*# residents 7-18 years old*	16.5	1	8.48	5	0.149	1	37.3	126	6.0	3.3
5	*# residents 25-49 years old*	16.5	2	8.48	3	0.149	2	37.3	126	6.5	3.4
6	*# residents 50-64 years old*	16.5	2	8.48	2	0.149	2	37.3	126	1.0	1.8
7	*manufactured housing*	16.5	2	8.48	2	0.149	2	37.3	126	4.0	2.5
8	*weekday*	16.5	1	8.48	2	0.149	1	37.3	126	5.5	2.4
9	*attached housing*	16.5	1	8.48	1	0.149	1	37.4	126	5.5	2.1
10	*apartment/condo*	16.5	3	8.48	2	0.149	3	37.4	126	1.0	2.3
11	*# residents 19-24 years old*	16.5	1	8.48	2	0.149	1	37.4	126	3.5	1.9
12	*backup generation*	16.5	1	8.48	1	0.149	1	37.4	126	4.0	1.8
13	*# residents 0-6 years old*	16.5	2	8.48	2	0.149	2	37.4	126	1.5	1.9
14	*unknown housing*	16.5	2	8.49	1	0.148	2	37.4	126	1.5	1.6
15	*medical equipment*	16.5	1	8.49	2	0.148	1	37.5	126	2.5	1.6
16	*# residents 65 and over*	16.6	1	8.49	1	0.146	1	37.5	126	2.5	1.4
17	*household income*	16.6	1	8.53	1	0.140	1	37.5	127	2.5	1.4
18	*evening, 5 pm to 8 pm*	16.7	1	8.61	2	0.133	1	38.7	127	3.0	1.8
19	*afternoon, 12 noon to 4 pm*	16.7	1	8.63	1	0.127	1	38.9	127	2.0	1.3
20	*summer*	16.8	1	8.71	1	0.119	1	39.7	127	2.0	1.3
21	*ln(annual MWh)*	17.0	1	8.82	1	0.098	1	39.7	128	1.5	1.1
22	*duration^2*	17.3	1	8.95	1	0.072	1	39.9	128	1.0	1.0
23	*duration*	17.9	1	9.44	1	0.000	1	41.6	130	1.0	1.0

The final model for residential customers is shown below:

Interruption Cost = f(ln(annual MWh), duration, duration^2, household income, summer, time of day)

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 5-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 5-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Residential

Model	RMSE	MAE	R-squared
Final	17.5	8.34	0.148
Global	17.3	8.28	0.165

5.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 5-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics and customer characteristics. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the more likely that the costs are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Customers are less likely to have a positive cost for an afternoon or an evening interruption versus any other time of day.

Table 5-4: Regression Output for Probit Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.130E-06	0.000	0.000
summer	0.541	0.019	0.000
afternoon	-0.266	0.026	0.000
evening	-0.755	0.024	0.000
Customer Characteristics			
ln(annual MWh)	0.038	0.018	0.035
household income	9.660E-07	0.000	0.004
Constant	-0.266	0.051	0.000

Table 5-5 describes the final GLM regression model which relates the level of interruption costs to customer and interruption characteristics. A few results of note:

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the higher the interruption cost;

- Customers have lower interruption costs for afternoon and evening interruptions than for those that occur at other times of day;
- Customers experience higher costs for summer interruptions than for non-summer interruptions; and
- Larger customers (in terms of annual MWh usage) have a higher cost for similar interruptions than otherwise equivalent, smaller customers.

Table 5-5: Regression Output for GLM Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.002	0.000	0.000
duration^2	-9.450E-07	0.000	0.000
summer	0.161	0.029	0.000
afternoon	-0.282	0.041	0.000
evening	-0.095	0.047	0.044
Customer Characteristics			
ln(annual MWh)	0.249	0.028	0.000
household income	1.850E-06	0.000	0.000
Constant	1.379	0.080	0.000

Finally, Table 5-6 shows the average values of the regression inputs for residential customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

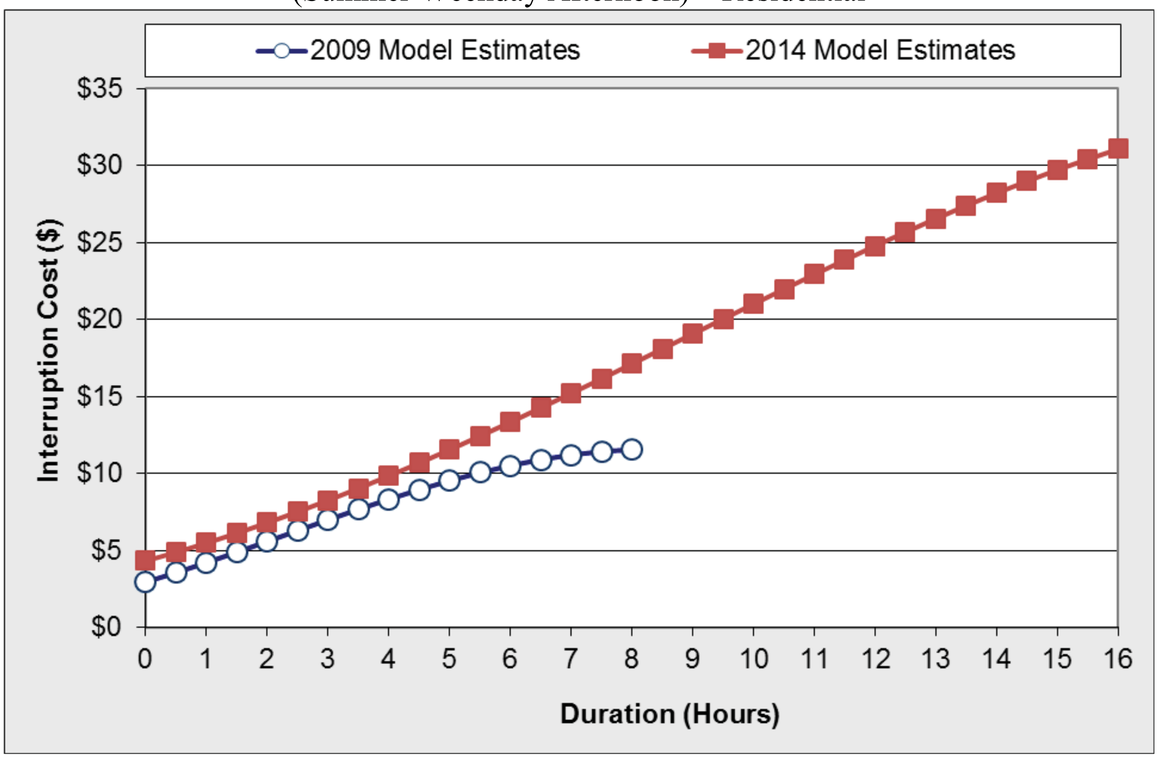
Table 5-6: Descriptive Statistics for Regression Inputs – Residential

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	34,212	168	0	60	60	240	1,440
duration^2	34,212	82,198	0	3,600	3,600	57,600	2,073,600
summer	34,212	73.4%	0%	0%	100%	100%	100%
afternoon	34,212	48.8%	0%	0%	0%	100%	100%
evening	34,212	29.1%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	34,212	2.4	0.3	1.9	2.4	2.9	4.4
household income	34,212	69,243	5,076	36,846	63,445	97,618	173,611

5.3 Comparison of 2009 and 2014 Model Estimates

Figure 5-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 5-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Residential



5.4 Interruption Cost Estimates and Key Drivers

Table 5-7 shows how residential customer interruption costs vary by season and time of day. The cost of a summer power interruption is substantially higher than a non-summer one, for all durations, seasons, and times of day. As for how interruption costs vary by time of day, costs are highest in the morning and night (10 PM to 12 noon). The weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 5-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Residential

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		**$3.9**	**$4.5**	**$5.1**	**$9.5**	**$17.2**	**$32.4**

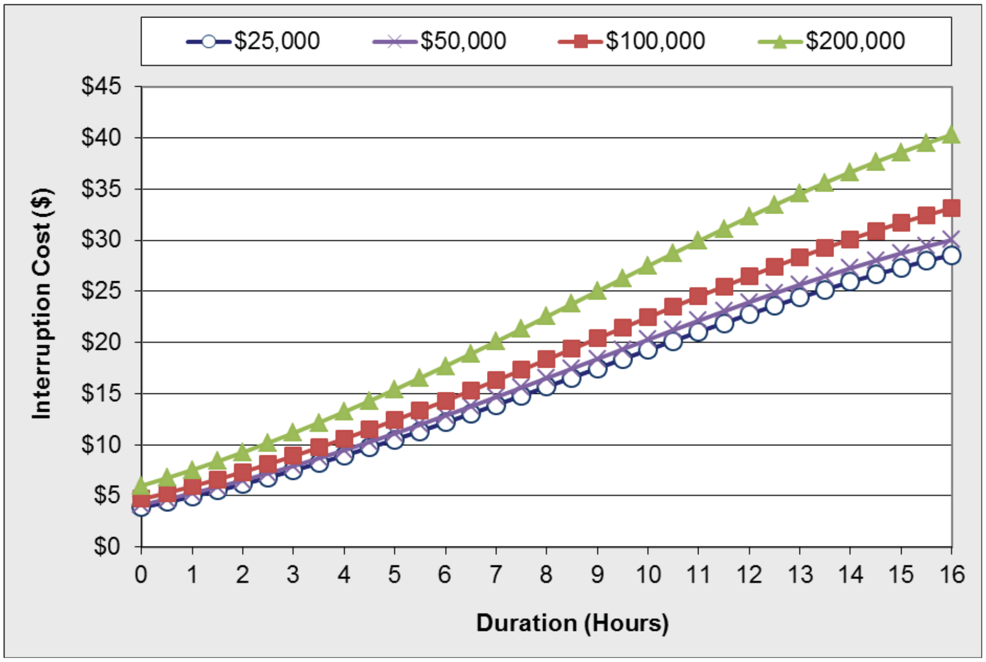
Based on the weighted-average interruption cost estimate, Table 5-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for residential customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 5-8: Cost per Event, Average kW and Unserved kWh – Residential

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

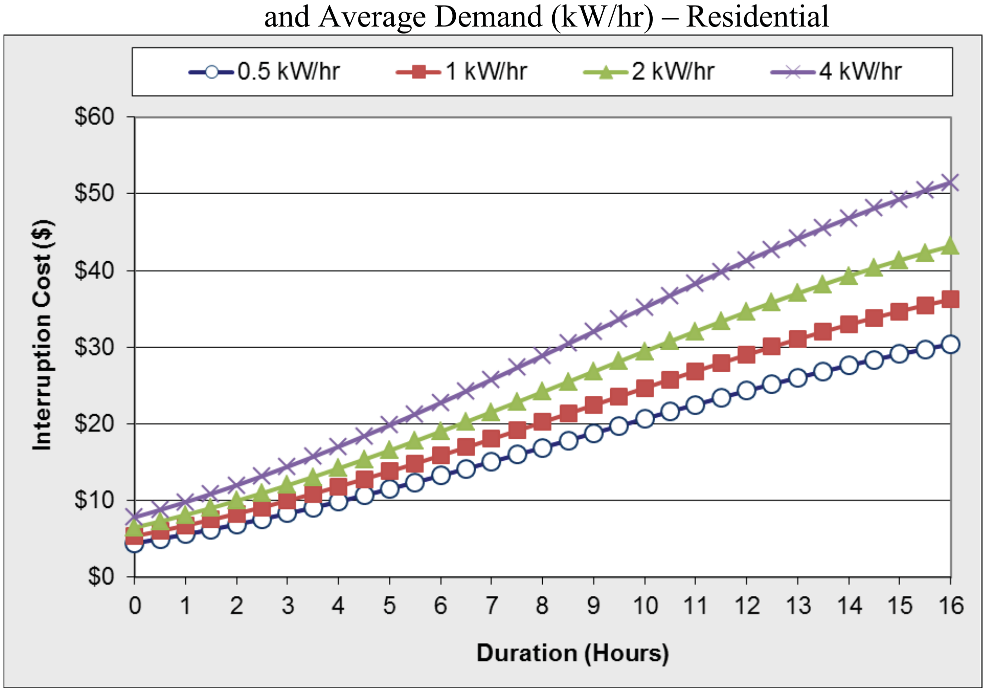
Figure 5-2 shows the residential interruption costs in the summer afternoon by levels of household income. Household income has a relatively modest impact on interruption costs. Between a household income of $50,000 and $100,000, the difference in interruption costs is only around 10% for all durations.

Figure 5-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Household Income – Residential



Finally, Figure 5-3 shows the residential interruption costs in the summer afternoon for various levels of average demand. Residential interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 20% from one level of average demand to the next.

Figure 5-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Residential



6. Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section. First, certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs. Thus, for example, it is unclear whether the higher interruption cost values for the southwest are purely the result of the hot summer climate in that region or whether those costs are higher in part because of the particular economic and market conditions that prevailed during the year when the study for that region was done. The same logic applies to the 2012 west study, which was the only survey to include power interruption scenarios of more than 12 hours, which makes it difficult to separate the effect of region and year from the effect of the relatively long interruption duration.

There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning for their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region. Unfortunately, the time periods when the chance of interruptions is greatest are not identical for all sponsors of the studies we relied upon, so interruption scenario characteristics tended to be different in different regions. Fortunately, most of the studies we examined included a summer afternoon interruption, so we could compare that condition among studies.

A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes. The absence of interruption cost information for the northeast/mid-Atlantic region is particularly troublesome because of the unique population density and economic intensity of that region. It is unknown whether, when weather and customer compositions are controlled, the average interruption costs from this region are different than those in other parts of the country.

Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

Finally, as described in Section 1, although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[12] These factors are not captured in this meta-analysis.

[12] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

DOC 11

1 Societal impact of loss of Bipole I & II or Dorsey for month of January ~C$4B, and ~C$20B for full year

Low societal impact ⟷ High societal impact

Short-term outage	Dorsey / Bipole I & II	Severe weather outage
Temporary (minutes–hours) inability to serve load • Black/brown-out	**Prolonged (week–year) inability to serve load** • Rolling blackouts • Shed industrial load • Prioritize residential heating	**Prolonged (day–week) inability to supply power** • Black-out until repair
MISO Value of Lost Load (VoLL) estimates: • Residential[1]: US$2/kWh • Small C/I: US$42/kWh • Large C/I: US$29/kWh	**MH VoLL estimate:** • C$10/kWh • Very unusual situation with uncertain long-term effects	**1998 Canada ice storm** • C$9/kWh **2012 Superstorm Sandy** • ~US$20B; 8.5M lost power

Bipole I & II transmission lines (for January)
- Un-served January demand * C$10/kWh = **~C$4B/mo**

Dorsey converter station (for a year)
- Un-served annual demand * C$10/kWh = **~C$20B/yr**

1. Likely higher for customers reliant on electric heating, and may underestimate modern reliance on electronics

Source: "Estimating the Value of Lost Load", London Economics (2013); "Manitoba Customer Interruption Cost Evaluation", R. Billington, PowerComp Associates (2001); "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages", Executive Office of the President (2013)

DOC 12

Table G4 - Prospective Peak Load Report – Energy

2024 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Energy Data

	Forecast # Cust. **C90**	Forecast Total KW.h Sales **Before DSM**	Forecast DSM KW.h Savings	Total KW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	KW.h Generated Adjusted **E12**
Residential							
Residential	521,539	8,087,025,562	(70,662,376)	8,016,363,185	621,648,231	532,028,416	9,170,039,833
Seasonal	18,417	72,502,074	-	72,502,074	5,622,348	4,811,803	82,936,225
Water Heating	2,318	8,219,875	-	8,219,875	637,430	545,535	9,402,840
Total Residential	542,274	8,167,747,510	(70,662,376)	8,097,085,134	627,908,010	537,385,755	9,262,378,898
GS Small - Single Phase							
Non-Demand	44,342	1,129,814,501	(49,413,609)	1,080,400,892	83,782,295	71,703,834	1,235,887,021
Demand	2,309	304,112,786	(17,147,522)	286,965,264	22,253,414	19,045,254	328,263,933
Subtotal	46,651	1,433,927,287	(66,561,131)	1,367,366,156	106,035,709	90,749,088	1,564,150,953
Seasonal	171	5,420,000	-	5,420,000	420,307	359,713	6,200,020
Water Heating	289	3,213,000	-	3,213,000	249,160	213,240	3,675,400
Total Single Phase	47,112	1,442,560,287	(66,561,131)	1,375,999,156	106,705,176	91,322,042	1,574,026,373
GS Small - Three Phase							
Non-Demand	16,660	992,787,716	(43,420,600)	949,367,116	57,481,723	62,013,369	1,068,862,209
Demand	5,931	1,509,705,185	(85,125,336)	1,424,579,849	86,254,625	93,054,620	1,603,889,095
Total Three Phase	22,591	2,502,492,901	(128,545,936)	2,373,946,965	143,736,349	155,067,990	2,672,751,303
Total G.S.Small							
Non-Demand	61,003	2,122,602,217	(92,834,210)	2,029,768,008	141,264,018	133,717,204	2,304,749,229
Demand	8,240	1,813,817,971	(102,272,858)	1,711,545,114	108,508,039	112,099,875	1,932,153,027
Sub-Total G.S. Small	69,243	3,936,420,189	(195,107,067)	3,741,313,121	249,772,057	245,817,078	4,236,902,257
Seasonal	171	5,420,000	-	5,420,000	420,307	359,713	6,200,020
Water Heating	289	3,213,000	-	3,213,000	249,160	213,240	3,675,400
Total GS Small	69,704	3,945,053,189	(195,107,067)	3,749,946,121	250,441,524	246,390,031	4,246,777,677
General Service - Medium	2,203	3,114,934,429	(157,830,775)	2,957,103,654	179,044,978	193,160,221	3,329,308,852
General Service - Large							
0 - 30 kV	378	1,929,573,552	(53,192,913)	1,876,380,639	96,722,569	121,526,463	2,094,629,671
30 - 100 kV	47	1,741,270,303	(14,229,762)	1,727,040,541	25,905,608	107,966,651	1,860,912,800
30 - 100 kV - Curtailable	1	207,000,000	(1,691,616)	205,308,384	3,079,626	12,834,938	221,222,948
Over 100 kV	19	1,507,339,453	(42,371,897)	1,464,967,556	-	90,229,606	1,555,197,162
Over 100 kV - Curtailable	2	1,836,000,000	(51,610,672)	1,784,389,328	-	109,903,285	1,894,292,613
Total G.S.- Large	447	7,221,183,308	(163,096,860)	7,058,086,448	125,707,803	442,460,943	7,626,255,194
SEP							
GSM	28	45,930,166		45,930,166	2,780,953	3,000,193	51,711,311
GSL 0 - 30 kV	3	2,102,712		2,102,712	108,389	136,185	2,347,287
Total SEP	31	48,032,878	-	48,032,878	2,889,342	3,136,378	54,058,598
Street Lighting	144,114	50,163,539	-	50,163,539	3,890,053	3,329,244	57,382,836
Sentinel Lighting	26,650	10,808,501	-	10,808,501	838,171	717,336	12,364,009
Total - Lighting	170,764	60,972,040	-	60,972,040	4,728,224	4,046,580	69,746,845
Total - General Consumers	785,422	22,557,923,354	(586,697,079)	21,971,226,276	1,190,719,881	1,426,579,908	24,588,526,064
Extra Provincial		-	-	-		-	-
Man Hydro - Construction		0		0	0	0	0
Integrated System	785,422	22,557,923,354	(586,697,079)	21,971,226,276	1,190,719,881	1,426,579,908	24,588,526,064

Table G5 - Prospective Peak Load Report – Demand

2024 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Demand Data

	CP Load Factor	CP @ Meter Before DSM MW	Forecast DSM MW Savings	CP @ Meter After DSM MW	Distrib Losses MW	Common Bus Losses MW	CP @ Gen. MW **D13/D14**	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**
Residential									
Residential	50.6%	1,820.1	(15.9)	1,804.1	178.3	123.9	2,106.3	90.0%	2,004.9
Seasonal	157.8%	5.2		5.2	0.5	0.4	6.1	8.0%	65.4
Water Heating	63.1%	1.5		1.5	0.1	0.1	1.7	80.0%	1.9
Total Residential	50.9%	1,826.8	(15.9)	1,810.8	178.9	124.4	2,114.2	87.4%	2,072.2
GS Small - Single Phase									
Non-Demand	62.4%	206.0	(9.0)	196.9	19.5	13.5	229.9	86.8%	226.9
Demand	66.4%	52.2	(2.9)	49.2	4.9	3.4	57.5	90.4%	54.5
Subtotal	63.2%	258.1	(12.0)	246.2	24.3	16.9	287.4	87.5%	281.4
Seasonal	162.5%	0.4		0.4	0.0	0.0	0.4	8.0%	4.8
Water Heating	68.1%	0.5		0.5	0.1	0.0	0.6	75.0%	0.7
Total Single Phase	63.4%	259.1	(12.0)	247.1	24.4	17.0	288.5	86.1%	286.9
GS Small - Three Phase									
Non-Demand	62.4%	181.0	(7.9)	173.1	13.3	11.7	198.1	86.8%	199.4
Demand	66.4%	259.0	(14.6)	244.3	18.8	16.5	279.6	90.4%	270.3
Total Three Phase	64.8%	439.9	(22.6)	417.4	32.2	28.1	477.7	88.9%	469.8
Total G.S.Small									
Non-Demand	59.7%	387.0	(17.0)	370.0	32.8	25.2	428.0	86.8%	426.4
Demand	62.6%	311.1	(17.6)	293.5	23.7	19.8	337.1	90.4%	324.8
Sub-Total G.S. Small	64.2%	698.1	(34.5)	663.5	56.5	45.0	765.1	88.3%	751.1
Seasonal	162.4%	0.4	-	0.4	0.0	0.0	0.4	8.0%	4.8
Water Heating	68.1%	0.5	-	0.5	0.1	0.0	0.6	75.0%	0.7
Total GS Small	64.3%	699.0	(34.5)	664.5	56.6	45.1	766.1	87.8%	756.6
General Service - Medium	73.0%	486.0	(24.7)	461.3	35.6	31.1	528.0	91.3%	505.2
General Service - Large									
0 - 30 kV	80.3%	273.7	(7.6)	266.1	17.5	17.7	301.3	89.9%	296.2
30 - 100 kV	91.3%	217.1	(1.8)	215.3	4.1	13.7	233.1	76.9%	280.0
30 - 100 kV - Curtailable	96.1%	24.5	(0.2)	24.3	0.5	1.6 †	26.3	95.6%	25.5
Over 100 kV	91.0%	188.6	(5.5)	183.1	-	11.4	194.5	85.8%	213.4
Over 100 kV - Curtailable	97.1%	215.2	(6.3)	208.9	-	13.1 †	222.0	85.3%	245.0
Total G.S.- Large	89.4%	919.1	(21.3)	897.7	22.1	57.5	977.3	84.7%	1,060.0
SEP									
GSM	47.3%	11.0		11.0	0.9	0.7	12.6	84.0%	13.2
GSL 0 - 30 kV	157.1%	0.2		0.2	0.0	0.0	0.2	10.9%	1.4
Total SEP	48.8%	11.2	-	11.2	0.9	0.8	12.8	77.0%	14.5
Street Lighting	76.2%	7.5	-	7.5	0.7	0.5	8.7	65.1%	11.5
Sentinel Lighting	76.2%	1.6	-	1.6	0.2	0.1	1.9	65.1%	2.5
Total - Lighting	76.2%	9.1	-	9.1	0.9	0.6	10.6	65.1%	14.0
Total - General Consumers	65.0%	3,951.2	(96.5)	3,854.7	294.9	259.4	4,409.0	87.2%	4,422.5
Extra Provincial	0.0%	-		-		-	0.0		
Man Hydro - Construction	73.0%	0.0		-	-	-	0.0		
Integrated System	65.0%	3,951.2	(96.5)	3,854.7	294.9	259.4	4,409.0		

† Demand for curtailable customers is forecast as if customers are not curtailed at time of system peak.

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Allocation Table

Prospective Cost Of Service Study
G&T Costs for Allocation of Net Export Revenue
(Excludes Non Tariffable Transmission)

		Generation Energy	Generation Demand	Transmission Energy	Transmission Demand	Total
Residential	Standard & All Electric	478.3	357.3	8.6	116.7	960.8
	Seasonal	4.3	1.0	0.1	0.3	5.8
	Water Heating	0.5	0.3	0.0	0.1	0.9
Total Residential		483.1	358.6	8.7	117.1	967.5
General Service Small:	Non-Demand	120.2	72.6	2.2	23.7	218.7
	Demand	100.8	57.2	1.8	18.7	178.4
	Seasonal	0.3	0.1	0.0	0.0	0.4
	Water Heating	0.2	0.1	0.0	0.0	0.3
Total General Service Small		221.5	129.9	4.0	42.4	397.9
SEP	GSM	n/a	n/a	n/a	n/a	-
	GSL	n/a	n/a	n/a	n/a	-
Total Interruptible		-	-	-	-	-
General Service Medium		173.6	89.6	3.1	29.3	295.6
General Service Large	0-30KV	109.2	51.1	2.0	16.7	179.0
	30-100KV	97.1	39.5	1.7	12.9	151.3
	30-100KV Curtailable	11.5	4.5	0.2	1.5	17.7
	>100KV	81.1	33.0	1.5	10.8	126.3
	>100KV Curtailable	98.8	37.6	1.8	12.3	150.5
Total General Service Large		397.8	165.8	7.1	54.1	624.8
Area & Roadway Lighting		3.6	1.8	0.1	0.6	6.1
Total General Consumers		1,279.6	745.7	22.9	243.6	2,291.8
Diesel		-	-	-	-	-
Export		n/a	n/a	n/a	n/a	-
Total System		1,279.6	745.7	22.9	243.6	2,291.8

Allocated Exports

Prospective Cost Of Service Study
Net Export Revenue on G&T Costs

		Generation Energy	Generation Demand	Transmission Energy	Transmission Demand	Total
Residential	Standard & All Electric	232.9	174.0	4.2	56.8	468.0
	Seasonal	2.1	0.5	0.0	0.2	2.8
	Water Heating	0.2	0.1	0.0	0.0	0.4
Total Residential		235.3	174.7	4.2	57.1	471.2
General Service Small:	Non-Demand	58.5	35.4	1.0	11.5	106.5
	Demand	49.1	27.8	0.9	9.1	86.9
	Seasonal	0.2	0.0	0.0	0.0	0.2
	Water Heating	0.1	0.1	0.0	0.0	0.2
Total General Service Small		107.9	63.3	1.9	20.7	193.8
SEP	GSM	-	-	-	-	-
	GSL	-	-	-	-	-
Total Interruptible		-	-	-	-	-
General Service Medium		84.6	43.6	1.5	14.2	144.0
General Service Large	0-30KV	53.2	24.9	1.0	8.1	87.2
	30-100KV Non Curtailable	47.3	19.3	0.8	6.3	73.7
	30-100KV Curtailable	5.6	2.2	0.1	0.7	8.6
	>100KV Non Curtailable	39.5	16.1	0.7	5.2	61.5
	>100KV Curtailable	48.1	18.3	0.9	6.0	73.3
Total General Service Large		193.7	80.7	3.5	26.4	304.3
Area & Roadway Lighting		1.8	0.9	0.0	0.3	3.0
Total General Consumers		623.3	363.2	11.2	118.6	1,116.2
Diesel		-	-	-	-	-
Total System		623.3	363.2	11.2	118.6	1,116.2