REFERENCE:

GAC/MH I-1 (e)-(h)

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following information:

a) The number of bills by month of LICO 125 customers with electric heat in the survey sample,
b) The number of bills by month of LICO 125 non-heating customers in the survey sample,
c) A bill frequency table for LICO 125 customers with electric heat in the form provided for basic residential customers in response to GAC/MH I-1 (a)-(d), including total kW.h in each block, total number of bills in each block, and a similar breakdown into smaller block sizes.

RATIONALE FOR QUESTION:

RESPONSE:

a) The following table presents the number of bills of LICO-125 customers with electric heat derived from the returns of 2014 Residential Energy Use Survey.

	LICO-125 Electric Heat	
	Unweighted Returns	**Weighted Returns**
Apr	580	63884
May	580	63884
Jun	580	63884
Jul	580	63884
Aug	580	63884
Sep	580	63884
Oct	580	63884
Nov	580	63884
Dec	580	63884
Jan	580	63884
Feb	580	63884
Mar	580	63884

b) The following table presents the number of bills of LICO-125 customers with non-electric heat derived from the returns of 2014 Residential Energy Use Survey.

	LICO-125 Non-Electric Heat	
	Unweighted Returns	Weighted Returns
Apr	743	78240
May	743	78240
Jun	743	78240
Jul	743	78240
Aug	743	78240
Sep	743	78240
Oct	743	78240
Nov	743	78240
Dec	743	78240
Jan	743	78240
Feb	743	78240
Mar	743	78240

c) Due to the small size of the LICO-125 determined survey returns in the lower blocks, the kWh blocks were collapsed. The following tables represent the weighted population estimates of Electric Heat LICO-125 customers by season for the 2014/15 fiscal year.

SPRING (MARCH - MAY)

(kWh/month)	#Bills In Strata	#Bills Cumulative	Consumption(kWh) In Strata	Consumption(kWh) Cumulative
1 - 200	7,056	7,056	737,729	737,729
201 - 500	11,390	18,446	4,160,814	4,898,543
501 - 750	10,732	29,178	6,684,192	11,582,735
751 - 900	7,595	36,773	6,273,455	17,856,190
901 - 1200	16,144	52,917	17,091,746	34,947,936
1201 - 1400	8,902	61,819	11,663,359	46,611,294
1401 - 1600	9,432	71,251	14,323,811	60,935,106
1601 - 1800	7,398	78,649	12,665,165	73,600,271
1801 - 2000	13,793	92,442	26,404,040	100,004,311
2001 - 2500	24,199	116,640	54,371,552	154,375,863
2501 - 3000	20,628	137,268	56,602,864	210,978,727
3001 - 3500	17,443	154,711	56,602,225	267,580,952
3501 - 4000	11,353	166,064	42,272,439	309,853,391
4001 - 5000	16,144	182,208	71,516,641	381,370,032
5001 - 50000	9,612	191,820	65,251,623	446,621,655

SUMMER (JUNE - AUGUST)

(kWh/month)	#Bills In Strata	#Bills Cumulative	Consumption(kWh) In Strata	Consumption(kWh) Cumulative
1 - 200	13,874	13,874	1,695,899	1,695,899
201 - 500	43,372	57,246	15,802,186	17,498,085
501 - 750	35,151	92,397	21,983,468	39,481,553
751 - 900	16,936	109,333	14,007,363	53,488,916
901 - 1200	32,215	141,547	33,788,615	87,277,531
1201 - 1400	12,495	154,042	16,225,574	103,503,105
1401 - 1600	8,757	162,799	13,192,790	116,695,895
1601 - 1800	7,228	170,026	12,281,293	128,977,187
1801 - 2000	4,657	174,684	8,824,490	137,801,677
2001 - 2500	6,521	181,205	14,511,196	152,312,873
2501 - 3000	3,963	185,167	10,740,172	163,053,044
3001 - 3500	939	186,106	2,953,142	166,006,186
3501 - 4000	794	186,900	3,002,682	169,008,868
4001 - 5000	644	187,544	2,886,275	171,895,142
5001 - 50000	1,049	188,593	9,191,711	181,086,853

FALL (SEPTEMBER TO NOVEMBER)

(kWh/month)	#Bills In Strata	#Bills Cumulative	Consumption(kWh) In Strata	Consumption(kWh) Cumulative
1 - 200	11,806	11,806	1,339,466	1,339,466
201 - 500	31,248	43,054	11,152,905	12,492,371
501 - 750	25,200	68,254	16,018,736	28,511,106
751 - 900	13,483	81,737	11,207,946	39,719,052
901 - 1200	27,816	109,553	29,213,500	68,932,552
1201 - 1400	16,494	126,047	21,447,860	90,380,412
1401 - 1600	12,689	138,736	19,045,510	109,425,922
1601 - 1800	10,362	149,098	17,675,294	127,101,216
1801 - 2000	7,228	156,326	13,752,272	140,853,488
2001 - 2500	14,242	170,568	31,541,888	172,395,376
2501 - 3000	10,234	180,802	27,864,507	200,259,883
3001 - 3500	5,770	186,572	18,336,461	218,596,345
3501 - 4000	2,782	189,354	10,379,263	228,975,608
4001 - 5000	1,988	191,342	8,592,507	237,568,115
5001 - 50000	2,171	193,513	14,622,366	252,190,481

WINTER (DECEMBER TO FEBRUARY)

(kWh/month)	#Bills In Strata	#Bills Cumulative	Consumption(kWh) In Strata	Consumption(kWh) Cumulative
1 - 200	1,660	1,660	220,125	220,125
201 - 500	9,159	10,819	3,338,323	3,558,448
501 - 750	10,150	20,969	6,372,952	9,931,400
751 - 900	4,672	25,641	3,887,066	13,818,466
901 - 1200	11,602	37,243	12,115,468	25,933,934
1201 - 1400	5,681	42,924	7,306,446	33,240,380
1401 - 1600	7,650	50,574	11,550,744	44,791,125
1601 - 1800	4,518	55,093	7,749,572	52,540,697
1801 - 2000	4,951	60,044	9,407,125	61,947,822
2001 - 2500	18,011	78,055	40,483,167	102,430,989
2501 - 3000	22,320	100,375	61,326,146	163,757,135
3001 - 3500	23,507	123,882	76,545,100	240,302,236
3501 - 4000	19,948	143,831	74,592,413	314,894,648
4001 - 5000	25,939	169,770	115,280,465	430,175,113
5001 - 50000	24,729	194,499	162,690,208	592,865,322

REFERENCE:

GAC/MH I-1e (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a description of the survey sample as requested, including an explanation of how the survey sample was derived and the categories of customers it contains.

RATIONALE FOR QUESTION:

RESPONSE:

Please refer to page 10 of 250 of the attachment to PUB/MH I-125a-d. As at November 1, 2014, there were a total of 466,398 accounts under the residential basic rate class that defined the sampling frame. A total of 20,000 residential accounts were randomly selected using a random number generating process. Excluded from the residential sampling frame were residential seasonal and residential diesel customers.

The sample of 20,000 accounts was derived in order to obtain approximately 5,000 returns. Prior survey experience suggested a 25% response rate. In order to receive the desired number of 5000 returns, a sample of 20,000 accounts was drawn. In total, 4,804 surveys were completed and returned, achieving a response rate of 24.0%. Based on the number of returns, the overall survey results are accurate within 1.5%, 19 times out of 20.

REFERENCE:

GAC/MH I-2a

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the average bill size in kW.h for a residential customer by month and by tariff subclass, for the past five years, for heating and non-heating customers separately.

RATIONALE FOR QUESTION:

RESPONSE:

The following tables show the average bill size in kWh for a residential customer by month and by tariff subclass for the past five years. The average bill was derived by dividing the total kWh's by the total number of customers.

RESIDENTIAL AVERAGE MONTHLY BILL (kWh)

Revenue Month	Basic Standard	Basic Electric Heat	Diesel	Seasonal Standard	Seasonal Electric Heat
2017/03	968	2,784	1,474		
2017/02	986	2,926	1,276		
2017/01	1,200	3,563	981		
2016/12	960	2,518	1,567		
2016/11	783	1,680	1,224		
2016/10	762	1,274	1,200	1,600	2,105
2016/09	815	984	1,259		
2016/08	889	953	909		
2016/07	860	962	1,046		
2016/06	761	1,067	1,394		
2016/05	752	1,474	1,085		
2016/04	883	2,279	1,658	935	2,207

RESIDENTIAL AVERAGE MONTHLY BILL

Revenue Month	Basic Standard	Basic Electric Heat	Diesel	Seasonal Standard	Seasonal Electric Heat
2016/03	954	2,675	1,350		
2016/02	1,020	3,035	1,248		
2016/01	1,166	3,374	1,393		
2015/12	932	2,424	1,248		
2015/11	821	1,772	1,037		
2015/10	720	1,155	1,213	1,775	2,244
2015/09	805	934	1,022		
2015/08	1,002	1,070	655		
2015/07	888	1,011	1,374		
2015/06	743	1,142	1,267		
2015/05	768	1,575	1,208		
2015/04	896	2,311	930	1,189	2,926
2015/03	1,063	3,200	1,663		
2015/02	1,111	3,430	1,473		
2015/01	1,229	3,609	1,810		
2014/12	1,047	3,070	1,153		
2014/11	874	2,087	1,147		
2014/10	761	1,309	1,274	1,839	2,599
2014/09	751	1,000	898		
2014/08	974	1,086	853		
2014/07	831	1,031	1,266		
2014/06	775	1,212	1,200		
2014/05	849	1,935	885		
2014/04	975	2,754	1,571	1,506	4,065
2014/03	1,102	3,438	1,350		
2014/02	1,209	3,850	2,141		
2014/01	1,301	4,129	1,485		
2013/12	1,048	3,179	1,395		
2013/11	903	2,173	1,285		
2013/10	718	1,255	903	1,764	2,540
2013/09	958	1,067	1,012		
2013/08	830	989	1,131		
2013/07	907	1,023	931		
2013/06	727	1,144	1,152		
2013/05	793	1,787	1,109		
2013/04	967	2,760	886	1,402	3,596

RESIDENTIAL AVERAGE MONTHLY BILL

Revenue Month	Basic Standard	Basic Electric Heat	Diesel	Seasonal Standard	Seasonal Electric Heat
2013/03	997	3,010	1,356		
2013/02	1,192	3,726	1,668		
2013/01	1,233	3,753	1,423		
2012/12	1,012	2,945	1,371		
2012/11	916	2,218	1,179		
2012/10	749	1,386	984	1,757	2,416
2012/09	825	1,026	981		
2012/08	956	1,036	1,056		
2012/07	988	1,121	1,007		
2012/06	754	1,127	1,151		
2012/05	762	1,503	1,026		
2012/04	854	1,973	1,409	1,118	2,816

REFERENCE:

GAC/MH I-2b

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate whether the estimate of 142,000 is the number of LICO-125 customers is the number in the sample or the estimated total Manitoba LICO-125 customers based on the number in the survey sample.

If the latter, explain how the estimate of 142,000 was derived from the sample.

RATIONALE FOR QUESTION:

RESPONSE:

The estimate of 142,000 is the estimated total Manitoba LICO-125 customers based on the weighted number of the survey returns.

The survey returns were weighted by billing class, dwelling type, fuel area, and First Nations status as described on page 11 of 250 of the attachment to PUB/MH I-125a-d. The weighting variables are present in the billing system and therefore are present in the sample frame. These variables were used to weight survey responses back to the residential basic population (at that time) of 468,398. Based on weighted survey responses of household income and people per household, the number of LICO-125 qualified customers was estimated to be 142,000.

LICO-125 status cannot be determined directly from the sample frame since household income and people per household are not variables present in the billing system (from which the sample frame was drawn).

REFERENCE:

GAC/MH I-7b

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the 2017 System Load Forecast.

RATIONALE FOR QUESTION:

RESPONSE:

Please refer to PUB MFR 65U-Attachment 1.

REFERENCE:

GAC/MH I-7b

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following information:

a) historical load factor data by class,
b) the derivation of the historical load factor data, and
c) the application of load factor to forecast kWh to produce class billing demands
d) Include workpapers and Excel spreadsheets, with data and formulas intact.

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) to c):

For all customer classes except those including the Top Consumers, the most current year's load factor for each class is used in determining forecasted demand. With regards to Top Consumers, the historical load factor for each customer is considered. Depending on each individual Top Consumer's current and forecast situation, either a one year load factor is used, or an average weighted five year or ten year load factor is used.

The load factor by class is derived using the total billed kWh divided by the total billed kVA, then further divided by 730 average hours per month. Once the actual load factor is determined, it is then applied to the forecasted energy (kWh) for each class to derive at the forecasted demand (kVA).

Attachment 1 ("Historical LF" Tab) is a spreadsheet showing five years of historical energy and demand data, and the calculated load factor. Note that there are two demand columns shown. "Demand Recorded" refers to the Measured Demand as recorded at the customer meter. "Demand Billed" refers to the Billing Demand units that were applied on customer bills. The Billing Demand differs from Recorded Demand for two reasons. First, "Demand Billed" figures shown for General Service Small and Medium sectors exclude the demand associated with the first 50 kVA for which no charge is applied. As a result, less demand is billed than recorded which results in a billed Load Factor in excess of 100% for certain classes.

In addition, the Billed Demand for General Service Medium and General Service Large customers includes contract demand charge provisions as set out in Manitoba Hydro's tariff, which are defined as the greatest of the following expressed in kVA:

1. Measured demand
2. 25% of contract demand
3. 25% of the highest measured demand in the previous 12 months.

Attachment 1 ("Fcst LF" Tab) provides the calculation of the forecast demand by class for fiscal years 2017/18 and 2018/19. Note that the load factor calculated based on actual 2016/17 billing data is applied to the forecasted kWh for each year to derive the projected demand for each rate class. The forecasted kWh and kVA shown on this tab correlate to the kWh and kVA shown in response to PUB/MH I-135, with the exception of the Large 30-100 and Large >100. The demands for these sub-classes vary slightly because of the fact that each individual Top Consumer is forecasted separately; therefore their demand is also forecasted individually, whereas the forecasted demands shown on Attachment 1 ("Fcst LF" Tab) for these sub-classes is based on the overall class average load factor.

Response to part d):

The Excel Attachment 1 containing historical load factor data by class for the past five years has separately been provided to the PUB and Registered Interveners.

REFERENCE:

GAC/MH I-6, Appendices 9.1 and 9.2 Updated

PREAMBLE TO IR (IF ANY):

GAC/MH I-6 requested the Excel spreadsheets used to derive the Proofs of Revenue. MH's response refers to PUB/MH I-135, which provides the calculation only under proposed rates, not under current rates.

QUESTION:

Please provide the workpapers and Excel spreadsheets (with formulas intact) used to derive the entire Proof of Revenue calculations in the updated Appendices, under both the current rates and the proposed rates.

RATIONALE FOR QUESTION:

RESPONSE:

Further to discussion with GAC Counsel on September 27, 2017, this Information Request has been withdrawn and a response is no longer required.

REFERENCE:

GAC/MH I-11

PREAMBLE TO IR (IF ANY):

MH's response to the GAC/MH I-11 request for a recent analysis of season variation in marginal cost refers to blacked-out table provided in response to PUB/MH I-131b.

QUESTION:

Please provide the following information regarding the table in PUB/MH I-131b-c:

a) Provide the levelized values for the summer and winter separately of generation capacity cost per kW.yr, generation energy cost per MW.h, and the all-in marginal cost in $/MW.h.
    i. If it is not possible for MH to provide an estimate of the variation of marginal cost with season without creating confidentiality concerns, explain how marginal cost-based seasonal rates could be designed or implemented.
b) Provide any in-house reports or other documents that describe the simulation model, give details on user inputs and options and describe its possible outputs.
c) Explain whether the base case simulation run that "corresponds to the IFF case" is:
    i. The average of 102 different system inflow conditions (as described on page 46 of Appendix 3.1),
    ii. one set of system inflow conditions that is the average of the 102 different conditions, or
    iii. something else.
d) Indicate what areas other than Manitoba are included in the simulation runs (e.g. MISO, Saskatchewan, other provinces)
e) Indicate whether the simulation model run assumes that the generation capacity on-line in each year is sufficient to meet load.
f) Indicate whether the simulation model of production costs also produces marginal generation capacity cost.
    i. If so, explain how.

g) Provide the non-confidential components of the estimation of marginal generation capacity cost, including all non-confidential assumptions made, and formulas and calculations used.
h) Explain how the summer and winter portion of marginal generation capacity cost is determined.
i) If the marginal generation capacity cost is based on the cost of a generic peaker, explain what elements of the calculation are considered confidential.
j) Indicate whether the estimates of generation capacity in the summer exceed zero.
k) Provide the ratio of summer to winter marginal generation capacity cost embedded in levelized marginal cost.
l) Provide the ratio of summer to winter marginal generation energy cost embedded in levelized marginal cost.
m) Provide the ratio of summer to winter "ALL-IN" marginal cost.
n) Specify how, mathematically, the seasonal marginal generation capacity and energy costs are combined to produce total marginal generation cost.

RATIONALE FOR QUESTION:

RESPONSE:

a) As noted in the response to PUB/MH I-131b, the generation marginal cost values, including the detailed breakdown of generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information. Public disclosure of portions of this response would result in the release of information considered to be confidential and commercially sensitive. GAC should request the PUB's IEC investigate if GAC wishes to pursue this matter further.

   In response to the question as to how marginal-cost based rates may be considered in the event that this information is commercially sensitive, Manitoba Hydro suggests that it may be possible to rely on publicly available pricing from Surplus Energy Program rates that are approved each week by the PUB. Seasonal trends in pricing may be discerned from the 52 weekly rate Orders issued by the PUB, which are summarized on pages 5 through 7 in the Report to the Public Utilities Board – Surplus Energy Program, found at Appendix 9.9 of this Application.

b) Manitoba Hydro uses its SPLASH (Simulation Program for Long-term Analysis of System Hydraulics) production-costing model to support the long-term resource planning processes including estimation of net export revenue and marginal costs analysis. SPLASH simulates system operational, revenue and cost impacts of changes to generating resources, interconnections, energy contracts or key input assumptions such as reservoir operating limits or export prices.

The SPLASH model determines the cost of system operation (production cost) on a monthly basis for a series of years into the future. The production cost is derived from the variable cost characteristics of the various generation sources and revenue is derived from surplus (opportunity) export sales. A simulation of system operation is undertaken for each of the 102 streamflow conditions between the years 1912 and 2013 in order to cover the range of possible flow conditions that may occur in the future. These factors combine to create a significant amount of complexity that must be accounted for in the simulation modeling tool.

The key simulation model outputs include: energy production (dependable and opportunity), future operating costs, operating revenues, and water levels and flows at key locations in the Manitoba Hydro system. Expected flow-related energy production costs and forecasted net flow-related revenues are required inputs into the marginal cost analysis.

c) The base case simulation run that “corresponds to the IFF case" is the average net revenue from simulation of 102 different inflow conditions.

d) The simulation includes representations of Saskatchewan, Ontario and MISO.

e) The simulation model run assumes that the generation capacity on-line in each year is sufficient to meet load.

f) The SPLASH production costing model does not produce marginal generation capacity costs. Please see Manitoba Hydro's response to Coalition/MH I-133a for an explanation of how the generation capacity costs were based on the market value for generation capacity contained in the electricity export price forecast.

g) As explained in Coalition/MH I-133, the generation capacity costs are based on the market value for generation capacity contained in the electricity export price forecast. As explained in Coalition/MH I-56, the electricity export price forecast is considered to be confidential and commercially sensitive. As such, Manitoba Hydro is unable to provide the information requested. The requested information is proprietary information belonging to a third party and Manitoba Hydro does not have consent to share this information.

h) As noted in the response to part a), the generation marginal cost values, including the detailed breakdown of generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information.

i) As explained in the response to part g), the information on the value of generation capacity comes from proprietary forecasts, thus all elements are considered confidential.

j) The value of generation capacity in the summer does exceed zero.

k) As noted in the response to part a), the generation marginal cost values, including the detailed breakdown of generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information .

l) As noted in the response to part a), the generation marginal cost values, including the detailed breakdown of generation marginal cost values, are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information.

m) As noted in the response to part a), the generation marginal cost values, including the detailed breakdown of generation marginal cost values, are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information.

n) Total Marginal Value (in cents/ kWh) = [(summer generation energy + summer generation capacity) + (winter generation energy + winter generation capacity + transmission capacity + distribution capacity] /2.

As noted in the response to Coalition/MH II-27a, the data in the "All-In" marginal cost columns in the table in PUB/MH I-131b are not used in DSM program analysis. Instead, DSM programs are analyzed using separate capacity and energy values provided in the Summer and Winter columns in the table in PUB/MH I-131b.

REFERENCE:

GAC/MH I-18

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate whether the common bus total energy in Appendix 8.5, page 3 is:

a) Calculated from the customer class total energy;
b) Determined from metering at the bus,
c) Something else. If so, how.

RATIONALE FOR QUESTION:

RESPONSE:

Common Bus Total Energy is determined from the metering at the bus.

REFERENCE:

GAC/MH I-18

PREAMBLE TO IR (IF ANY):

QUESTION:

If the common bus total energy in Appendix 8.5, page 3 is calculated from the customer class total energy, please provide the calculation, including the loss factors applied to the total energy of each customer class.

RATIONALE FOR QUESTION:

RESPONSE:

As indicated in response to GAC/MH II-9, the Common Bus total energy is measured at the bus and not calculated from the customer class total energy.

REFERENCE:

GAC/MH I-23

PREAMBLE TO IR (IF ANY):

QUESTION:

Please specify the changes in the planned expenditures and calculation of avoided transmission cost that led to a decline in the value since 2010.

RATIONALE FOR QUESTION:

RESPONSE:

The 2015 Transmission Marginal Cost study used data for the applicable projects, project costs, and interest rate variables that were current for August 18, 2015. The decrease in marginal transmission cost from 2009 to 2015 is driven by the decrease in the discount rate from 5.75% to 4.15%.

Please see the response to Coalition/MH I-132k for more details on the change in the marginal cost.

REFERENCE:

GAC/MH I-23

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the derivation of the Company's 2010 estimate of avoided transmission cost, including the relevant CEF, and all reports, workpapers, and Excel spreadsheets (with formulas intact).

RATIONALE FOR QUESTION:

RESPONSE:

The derivation of Manitoba Hydro's 2010 estimate of avoided transmission cost was based on approved capital projects at the time. The 2010 report is provided in response to GAC/MH II-18a and contains the marginal cost calculation as well as all the supporting data and formulas.

REFERENCE:

GAC/MH I-24

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the workpapers and Excel spreadsheets (with formulas intact) underlying Manitoba Hydro's current estimates of avoided T&D, as requested in GAC/MH I-24.

RATIONALE FOR QUESTION:

RESPONSE:

The derivation of Manitoba Hydro's estimates of avoided transmission and distribution costs is based on approved capital projects. The Transmission and Distribution Marginal Cost Estimate Reports provided in response to GAC/MH I-39 contains all the raw data, calculations and formulas used.

REFERENCE:

GAC/MH I-26a

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's response to GAC/MH I-26a refers to the use of customer maximum demand in the Cost of Service Study. IR GAC/MH I-26a is a question about cost causation, not about the COSS methodology.

QUESTION:

Please indicate what transmission, subtransmission, and distribution plant capacity, other than service drops, is driven by customer maximum demand. Include relevant cites to Company T&D planning manuals.

RATIONALE FOR QUESTION:

RESPONSE:

<u>Transmission:</u>
Transmission does not plan plant capacity based on customer maximum demand, but on provincial coincident peak load. Please see the responses to PUB/MH I-118a and PUB/MH II-71a regarding Transmission load forecasts and relevant planning documents.

<u>Marketing & Customer Service (Subtransmission and Distribution):</u>
All (100%) of subtransmission and distribution plant capacity is driven by the coincident peak demand of all customers in the study area.

The following are excerpts from the Distribution Planning Standard:

"The distribution system shall be planned to have adequate capacity and reliability to meet customer's needs and expectations."

"The purpose of planning is to develop and expand Manitoba Hydro's distribution system by reacting to present load requirements and by anticipating future load growth. This ensures adequate capacity is available to meet customer requirements".

"Load Flow Models examine voltage, current flow and phase imbalance of the primary distribution. Peak load conditions shall be modelled with 100% of peak feeder load to ensure the following:

1. *Sufficient station capacity exists to ensure customer supply.*
2. *Sufficient feeder capacity is available.*
3. *Feeder ties to other stations are viable"*

REFERENCE:

GAC/MH I-35a

PREAMBLE TO IR (IF ANY):

The response to GAC/MH I-35a appears to be focused on energy production by baseload and intermediate plants.

QUESTION:

Please provide the non-fuel O&M costs reflected in the estimate of marginal generation capacity cost per kW.yr.

RATIONALE FOR QUESTION:

RESPONSE:

The response to GAC/MH I-35a provides the non-fuel variable O&M costs for all the thermal and hydro generation which Manitoba Hydro owns in $/ MWh as requested in GAC/MH I-35a.

As explained in the response to Coalition/MH I-133a, the generation capacity costs are based on the market value for generation capacity contained in the electricity export price forecast. As explained in Coalition/MH I-56, the electricity export price forecast is considered to be confidential and commercially sensitive. As such, Manitoba Hydro is unable to provide the information requested. The requested information is proprietary information belonging to a third party and Manitoba Hydro does not have consent to share this information. GAC should request the PUB's IEC investigate if GAC wishes to pursue this matter further

REFERENCE:

GAC/MH I-38

PREAMBLE TO IR (IF ANY):

In response to GAC/MH I-38, MH addresses the cost-effectiveness of the future expenditures on Keeyask, net of sunk costs.

QUESTION:

Please indicate whether MH believes that the benefits of the Keeyask project will equal or exceed its total revenue requirements:

a) Through 2037,

b) Over the project's useful life of approximately 70 years.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro has assumed that the question is intended to measure the incremental revenue contribution of Keeyask as its definition of "benefits" as opposed to also including the value of collateral benefits of the project and/or relative benefits (in the form of lesser ratepayer impacts) of Keeyask as compared to a now theoretical decision to meet future load growth with a different choice of new resource. Manitoba Hydro has not updated that latter analyses as the present economic and ratepayer impacts abundantly favor completing the Keeyask project.

   In practice, once it enters service the Keeyask Generating Station becomes a system asset supporting the entirety of Manitoba Hydro's domestic and extra-provincial revenues. Nonetheless, based on the 2017 Load Forecast, it is not anticipated that the incremental capacity of Keeyask will be required to service domestic load until early in the 2030's. As such, for simplification, if the incremental revenues of Keeyask are deemed to be solely associated with new export contract and opportunity exports then it is not expected that Keeyask will produce sufficient revenue to fully offset its full cost burden. Based on the current capital budget, interest rate and export price outlook, the deficiency is substantial in the period between In Service Date (2021) and 2037. Table 2.21 of Tab 2, page 21 illustrates the issue. In the initial years after in-service, incremental export revenues will be approximately $300 million per year below the incremental revenue requirements driven by the operating and carrying costs of the Keeyask project.

b) Such an analysis requires assumptions of export prices, domestic rates, interest rates, capital structure and operating costs for the next 70 years. Manitoba Hydro has not undertaken this analysis.

REFERENCE:

GAC/MH I-39 and Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the workpapers and Excel spreadsheets (with formulas intact) underlying Manitoba Hydro's current estimates of marginal T&D cost, as requested in GAC/MH I-39 and shown in the Attachment.

RATIONALE FOR QUESTION:

RESPONSE:

Please see response to GAC/MH II-13.

REFERENCE:

GAC/MH I-39, Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following study reports:

a) SPD2010/02 referred to on page 5 of the Attachment.

b) SPD 04/05 referred to on page 7 of the Attachment.

RATIONALE FOR QUESTION:

RESPONSE:

Please see attached for the requested reports.

The most recent revision of the document Marginal Transmission Cost Estimates SPD 2015/11 was provided the response to GAC/MH I-39, and supersedes the past versions of the Transmission Marginal Cost reports attached to this IR.

Manitoba Hydro

TRANSMISSION PLANNING & DESIGN DIVISION

SYSTEM PLANNING DEPARTMENT

REPORT ON

2009 MARGINAL TRANSMISSION and DISTRIBUTION COST ESTIMATES

SPD 2010/02

Stamps here

PREPARED BY:

G. Fuerst

REVIEWED BY:

J. Shewchuk, P. Eng
K. Johnson, P. Eng

PROVINCE OF MANITOBA
2013 02 06
J.E.J.
SHEWCHUK
Member
25185
REGISTERED PROFESSIONAL ENGINEER

APPROVED BY:

Ron W. Mazur

Ron W. Mazur

Recommended for Implementation

DEPARTMENT: Ron Mazur 2013-01-06

DIVISION: G Neufeld

DATE: 2013 02 11

DISTRIBUTION

Executive
T.E. Tymofichuk
L. Kuczek
B. Reed

Transmission Planning & Design Division
G.H. Neufeld
S. Johnson
B. Petterson
B.C. Jorowski
G. Mullin
P. Gordon
M. Aikens

Corporate Strategic Review Division
I. Page

TC & LM Division
S. A. Mailey
W. Mueller
J. Wortley
G.B. Penner
M. Adamkowicz

Apparatus Maintenance
W. Wittmeier
G. Parent

Customer Service & Distribution
J. Kreml
J. Hall
D. Case
S. Dunn
G. Paskaruk
J. Cooke
C. Steele

Others
L. Demers
C.A. Nieuwenburg
G. Gray

Transmission System Operations
L. Midford
L. St. Hilaire
A.A. (Tony) Clark
A. Pinder
M. Rheault

Industrial & Commercial Solutions Division
D. Friesen
A.P. Gibson
B. De Monye

Power Planning Division
J. Flynn

1. Executive Summary

The objective of this report is to update the marginal Transmission and Distribution costs that were produced in the Marginal Cost study in 2004. This report formally finalizes the 2009 marginal cost estimate dollars. This report also addresses Public Utility Board questions on the 2004 report related to load factor, overhead transformers, operation and maintenance, and methodology assumptions.

By using the one year deferral (OYD) method, the current study determined the following long-term marginal costs:

<u>2009 Marginal Cost Estimate (2009 Dollars)</u>

Transmission - $51.20 /(kW·Year)

Distribution - $61.05 /(kW·Year)

T&D Total - <u>$112.25 /(kW·Year)</u>

In 2004, the study determined marginal costs for three categories: Transmission, Subtransmission and Distribution. In the current 2009 study, the Subtransmission category has been eliminated and these projects have been distributed between the Transmission and Distribution categories. To make a comparison to this year's marginal cost estimate, the 2004 marginal cost estimate has been restated utilizing only two categories as follows:

<u>2004 Marginal Cost Estimate (escalated to 2009 dollars)</u>

Transmission - $60.41 /(kW·Year)

Distribution - $64.32 /(kW·Year)

T&D Total - <u>$124.73 /(kW·Year)</u>

In 2009 the estimate of marginal cost is very similar to the 2004 estimate with a decrease of about 10%. One possible reason for the decrease is improvement to the methodology for determining the degree to which a project is capacity related. In the 2004 study, major projects were assumed to be 100% capacity related even if only a portion of the project was capacity related. Projects are now categorized on the percentage of the project that is capacity related. This would tend to increase the 2004 marginal costs compared to 2009.

2. Table of Contents

3. Introduction

For various purposes such as the evaluation of demand side management (DSM) programs and equipment losses, there is a need to estimate the additional (incremental) cost incurred by an increase in capacity and energy requirements, or equivalently the cost that can be avoided by not having to increase capacity and energy requirements to serve additional load. Such an incremental cost is labeled “marginal cost” or “avoided cost”.

The marginal cost for a power system is usually split into three system levels: generation, transmission and distribution (T&D). The marginal cost for generation includes both capacity and energy components because generation resources must meet both capacity and energy requirements. The marginal cost for transmission and distribution has only a capacity component because these facilities are installed solely on the basis of capacity requirements. The maximum requirement for capacity occurs during the winter period for the Manitoba Hydro system. Therefore, T&D facilities are sized to meet the winter peak load (demand).

This report provides current marginal (or avoided) T&D cost estimates for the Manitoba Hydro system. The results supersede the previous marginal T&D costs originally produced in the 2004 marginal cost study.

4. Recommendations

Manitoba Hydro should utilize the marginal values in Table A below as the updated (2009) estimate of Transmission and Distribution components of marginal cost.

Table A
Levelized Marginal T&D Costs (2009 constant dollars)

	Transmission ($/(kW·Year))	Distribution ($/(kW·Year))
Average (Mean)	51.20	61.05

These Transmission & Distribution marginal costs are non-area specific and are valid for a winter peak system. They are based on the “T&D Capital Expenditure Forecast (CEF09-1)” for the period of 2009/10 to 2019/20 and the Corporate “Electric Load Forecast” for the same period. The costs are derived using the one year deferral (OYD) method.

These marginal costs are to be adjusted by the Corporate rate of inflation when applied to a year other than 2009.

It is recommended that this marginal cost study should be updated in 2014-15 or earlier, as needed.

Note:
These marginal costs are non-area specific since they are an average derived from the total of the defined capital projects in the system over a 10 year period *[Appendix B, Tables B.1-3]*. Caution must be exercised in utilizing these marginal costs because some applications may have unique characteristics which differ from the average.

5. Assumptions

Summarized below are the assumptions used for the marginal T&D cost estimates:

- T&D facilities are sized to meet the winter peak load (demand). Load factor is not used as a result.
- T&D marginal costs are not area-specific (i.e., do not vary by area).
- The entire T&D system is equally affected by a load reduction on a percentage basis.
- The load-growth related investment plan contained in "T&D Capital Expenditure Forecast (CEF09-1), 2009/10– 2019/20" is assumed to meet winter system peak loads which are considered to be the net total peaks (MW) in the base-case scenario in "Electric Load Forecast, 2009/10 to 2019/20".[1]
- T&D capital expenditures in the 10 year period of CEF09-1 are a typical representation of the long-term future beyond the 10 year planning horizon.
- Overhead transformers and secondary services (i.e. the portion of distribution from distribution transformers to customer meters, which are typically 347/600V, 120/208V, etc.) are for individual customers and the associated costs are usually covered by the customer. These costs are required for the connection of new customers, and therefore can not be deferred by an incremental change in demand by those customers.
- Operation and Maintenance (O&M) costs weren't included in the Marginal T&D costs because the impact is small and incremental O&M due to a small change in demand is difficult to determine: it is estimated that including these costs may add approximately 1% to 2% in the avoided T&D costs.

Note that an item is said to be "capacity-related", "load-growth related" or "load-related" if it is driven by the need for capacity expansion in order to accommodate the forecasted system load growth or to meet the forecasted system peak loads.

[1] The net total peak is defined as the maximum hourly demand in a given year, required to meet the needs of Manitoba customers on the integrated system. It does not include diesel generation, industrial self-generation, exports, losses associated with exports/imports, and station service loads.

6. Methodology

In 2004, a report was done to develop a methodology for estimating marginal Transmission & Distribution (SPD 04/05 - Marginal Transmission & Distribution Cost Estimates). It concluded that the one-year deferral (OYD) method should be used to develop future marginal T&D costs.

6.1. One-Year Deferral (OYD) Method

In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth. This load reduction has the ability to defer by one year the cash flow of transmission (or distribution) associated with the load, resulting in a savings in capital expenditure. An analysis of this savings in cash flow on a present value basis is undertaken in order to determine the overall savings over the 10 year period. This value can be represented as a $/(kW·year) value that is the avoided cost of the Transmission (or Distribution) component.

The restriction on the deferral time is consistent with the planning practice that Transmission and Distribution capital investments are planned to meet the forecasted annual peak load.

The following one year deferral method was used to calculate marginal Transmission & Distribution cost estimates.

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ [\Delta L_{ave} \sum_{k=1}^{N} \frac{1}{(1+i)^k}]$$

C_{avoid} – avoided cost (marginal cost).

k – fiscal year with $k = 0$ representing the current year.

N – study period in years for which the marginal costs are estimated; this includes the future years within the T&D planning horizon with well defined capital expenditures (10 years).

i – real discount rate, i.e., discount rate without the effect of inflation.[2]

ΔL_{ave} – average annual load growth over the study period.

I_k – load-growth related investments (capital expenditures) for year *k* expressed in terms of "constant-worth" dollars, which do not escalate with time. Note that "load-growth related" is used to describe the investments driven by the needs for capacity expansion to accommodate the forecasted load growth.

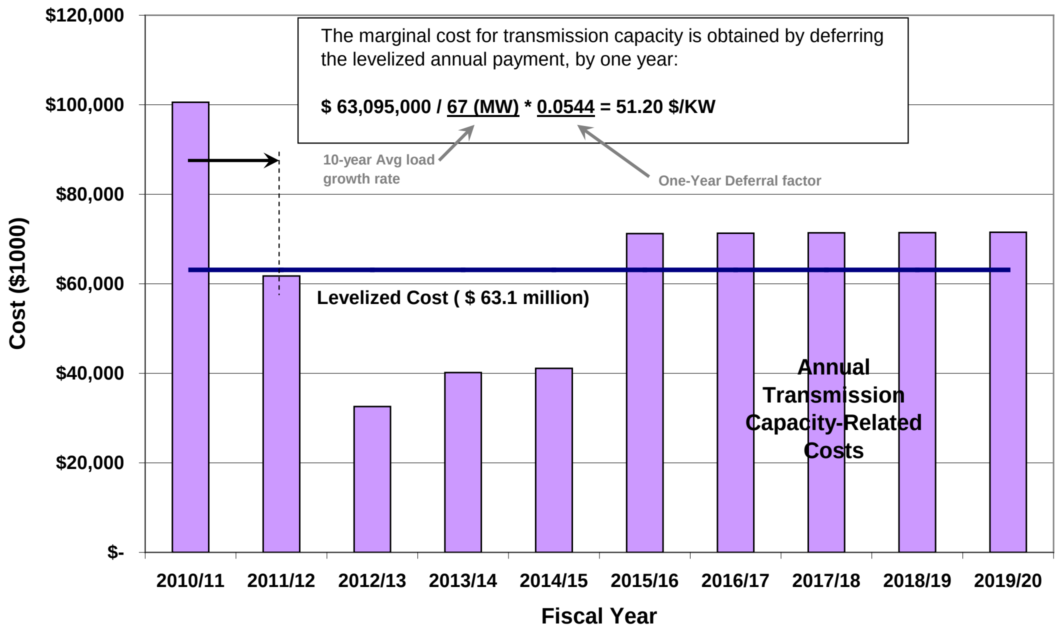
6.2. Levelized Cost

Over a 10 year planning period, the capacity capability of the system increases through the enhancements and/or additions of the hydro stations and service lines. The costs for these capacity additions vary on an annual basis because of the timing and sizing of the individual project. Collectively, these system enhancements are required to satisfy the growth of the future load increases. The levelized annual cost represents a constant stream of annual costs which give an equivalent present worth value when compared to the original cost stream. The marginal costs represent the deferral of the levelized cost by 1-year. The large number of projects which make up the system improvements over the 10 year period contributes to a stable, representative estimate of the system marginal cost.

[2] *i* is taken to be the real weighted average cost of capital in G911-1, issued 2009 05 19.

The OYD formula can be broken down to explain how it takes the costs of the capacity-related projects and uses the levelized cost over the 10-year planning period and defers it by 1-year. By using the transmission capacity-related costs, for an example, the graph below *[Table B]* can show how it gets the levelized costs over the 10 year study period.

Table B: Derivation of Marginal Cost - Transmission Capacity



7. Calculation of Marginal Costs

This section explains the preparation of the data for the marginal T&D cost estimates, which include annual load growth rates and annual load-growth related capital expenditures.

7.1. Forecasted System Peak Loads

The forecasted total system peak loads for the years 2009/10 to 2019/20 are provided in the "Manitoba Hydro Electric Load Forecast 2009/10 to 2029/30" *[Appendix A].*
The average annual load growth over the 10-year study period (2010/11 to 2019/20) is 67 MW. *[see Table C]*

Table C
Forecasted System Peak Loads

K	Fiscal Year	Total System Peak Load (MW)	Load Growth per Year (MW)*
0	2009/10 (current year)	4333	
1	2010/11	4407	74
2	2011/12	4499	92
3	2012/13	4570	71
4	2013/14	4633	63
5	2014/15	4733	100
6	2015/16	4789	56
7	2016/17	4845	56
8	2017/18	4893	48
9	2018/19	4942	49
10	2019/20	5007	65
Average			67

*Note: 67 MW/Year is the 10-year average load growth rate.

7.2. Division of Marginal Costs into Transmission & Distribution

The marginal T&D cost was divided into transmission, distribution and sub-transmission components in the 2004 marginal cost study. In this study, sub-transmission costs were absorbed into either transmission or distribution. They are defined as follows:

- *Transmission*: includes assets for bulk transmission of power. Specifically, it consists of transmission lines and terminal stations.[3]
- *Distribution*: includes assets for delivering power from terminal stations to customers.

7.3. Study Period

The latest T&D Capital Expenditure Forecast (CEF09-1) was issued in November 2009, and it includes the years 2009/10 to 2019/20. Each fiscal year is identified by a number k ($k = 0, 1, 2, 3, \cdots, N$) with *N=10*. The number $k = 0$ represents the current fiscal year of 2009/10. Considering that the capital expenditures for the current fiscal year cannot be deferred in practice, marginal costs are based on the study period of year 1 to 10 (i.e. 2010/11 to 2019/20).

7.4. Annual T&D Capital Expenditures

This section is to determine MB Hydro's increased capacity related expenditures that will be required to satisfy load-growth over the 10-year period.

[3] Terminal stations are defined as those providing connections between major transmission voltage levels (115 kV and above) or between major transmission and subtransmission voltage levels (66 kV, 33 kV).

7.4.1. T&D Capital Budget

The T&D capital budget is divided into major and domestic items. The major items are typically over $2,000,000 and each of them has a Capital Project Justification (CPJ) and a Capital Expenditure Revision (CER).

Domestic items consist of many smaller projects that are typically under $2,000,000. They consist of additions, improvements and maintenance to transmission lines; development and upgrades to communication systems; additions and replacement of field maintenance equipment; as well as station upgrades.

Capital budget items in the Transmission Planning & Design (TP&D) and Distribution Planning & Design (DP&D) areas that are load-growth related are selected for use in the marginal cost study.

7.4.2. Analysis of T&D Capital Expenditures

This section is to identify the load-growth related part of the TP&D and DP&D capital expenditures *[Appendix B]*. A load related capital item may be driven by several factors in addition to load growth. The following guidelines are used for allocating a capital item between load-related and non-load-related portions:

1) Major items: *[Appendix B, Table B.1]*

- 100% load related if it is primarily driven by load growth.
- Various percentages if it is partially driven by load growth[4].
- 0% load related if it is driven by factors other than load growth.

The major items are analyzed on a project-by-project basis and the results are summarized in Appendix B, Table B.1.

The transmission major budget in years 2015 to 2020 is judged to be uncharacteristically low, probably because not all system improvements for those future years have yet been identified. To be more representative of expected expenditures, an average cost over the first 6 years was used for

4 Each major item has a CPJ associated with it and in the justification of the project it states what portion of the project is capacity related along with an explanation.

capital expenditures for years 6-10 (2015/16-2019/20). [*Appendix B, Table B.4]*

The Distribution major budget in years 2013 to 2020 does not yet have capacity-related projects defined in this years' CEF (Capital Expenditure Forecast) *[Appendix B, Table B.4].* In discussions with Distribution Planning, it was concluded that a reasonable estimate for years 2013 to 2020 would be as follows:

- Take the average cost of the first 4 years (2009-2012)
- Add an extra $20 million to the average cost, for 2011 to 2016, due to upcoming major upgrades/new installations for stations St. James, Dawson, St. Vital, Mohawk, McPhillips and Harrow.

2) Domestic items: *[Appendix B, Tables B.2 & 3]*

Unlike major items, TP&D and DP&D domestic items include many small projects. The annual domestic budgets have been projected for future years within the planning horizon, but are not defined in detail. Therefore, the 2009/10 domestic budgets were analyzed and it is assumed that in 2009/10 is representative of future years. The domestic budgets for years beyond 2009/10 were scaled using a 2% inflation rate.

a) Transmission domestic budget: (Appendix B, Table B.2)

Transmission budget was filtered by Transmission Projects to include only capacity-related projects.

b) Distribution domestic budget: (Appendix B, Table B.3)

The DP&D domestic budget, for 2009/10 contributes to 48% of the costs when comparing it to the total 2009/10 Customer Service[5] & Distribution Domestic Budget. Therefore, it is assumed that the distribution-related budget for DP&D is 50% of the Customer Service & Distribution domestic budget *[see Table D].*

[5] Customer Service Budget includes mainly A&B Work Orders that pertains to single residential/commercial connections, line maintenance, ice melting, etc. that occurs at the District level. The Customer Service Budget is not included in this T&D Marginal Cost Study.

Table D

Distribution Domestic Budget

	Budget Costs (in 2009/10)	
Customer Service & Distribution Domestic Budget[6]	$115,900,000	(A)
Distribution Domestic Budget[7]	$55,736,510	(B)

Distribution Related Portion (B/A): **48.1%**

Summarized in Appendix B, *[Tables B.2 & 3]* is the analysis of the TP&D and DP&D domestic budgets provided in "2009/10 T&D Domestic Reports" issued by the Financing Department, T&D. According to Table B.3 in Appendix B, about 52.6% of the DP&D domestic budget is load related. Consequently, for purposes of this study it is assumed that a 50/50 split between load and non-load related expenditures is appropriate.

According to Table B.2, about 9.3% of the Transmission domestic budget is load related. Therefore, for purposes of this study it is assumed that 10% of the Transmission budget expenditures over the study period are load related.

The above described budget costs are then combined to yield the total capacity/load-growth related expenditures *[Appendix B, Table B.4]*. By utilizing the calculated load related percentages, the appropriate load-related expenditures are determined for the next 10 budget years.

6 Distribution & Customer Service Budget originates from the Capital Expenditure Forecast (CEF09-1).
7 The 2009/10 Distribution budget is calculated from the DP&D Annual Domestic Budget as stated in Appendix B, Table B.3

The load-growth related (capacity related) cash flows for the different categories are given in Table E *[referring to Appendix B, Table B.4]*.

Table E

Load-Growth Related Annual Investment Streams Expressed in Terms of "Constant" 2009 Dollars* (In Thousands of Dollars)

K	Fiscal Year	Transmission	Distribution	Transmission & Distribution Total
0	2009/10 (current year)	149,910	54,505	204,415
1	2010/11	100,575	70,400	170,975
2	2011/12	61,760	89,205	150,965
3	2012/13	32,570	71,610	104,180
4	2013/14	40,180	82,880	123,060
5	2014/15	41,115	83,505	124,620
6	2015/16	71,235	84,155	155,390
7	2016/17	71,305	64,805	136,110
8	2017/18	71,365	65,455	136,820
9	2018/19	71,435	66,130	137,565
10	2019/20	71,505	66,830	138,335

8. Comparison with Existing Marginal Costs

8.1. Results of Previous Study

The last Marginal T&D cost study was conducted in 2004. The marginal cost components produced in that study were as follows (in 2004 constant dollars):

Transmission = $45.44 /(kW·Year)

Subtransmission = $22.09 /(kW·Year)

Distribution = $40.93 /(kW·Year)

In 2004, the study determined marginal cost for three categories: Transmission, Subtransmission and Distribution. In the current 2009 study, the Subtransmission category has been eliminated and these projects have been distributed between the Transmission and Distribution categories. To make a comparison to this year's marginal cost update, the 2004 marginal cost estimate has been restated utilizing only two categories as follows (in 2004 constant dollars) [Table C.3, Appendix C]:

Transmission* = $52.38 /(kW·Year)

Distribution* = $55.77 /(kW·Year)

* - small discrepancy (0.28%) between the original and the re-calculated numbers due to the effect of rounding in original calculation.

8.2. Comparison

The restated transmission and distribution marginal costs recommended in the 2004 marginal cost study were $52.38/(kW·Year) and $55.77/(kW·Year), respectively *[see Appendix C, Table C.3]*. When these values are escalated to 2009 dollars *[see Table F]* and compared to the 2009 marginal costs, they show a decrease over the 5-year period.

Table F
Marginal Cost Comparison

	Previous study 2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	New Study 2009/10
GDP Price Deflator [8] (Canada)		3.5%	3.5%	2.4%	3.3%	2.7%	-0.9%	
Transmission	$52.38	$54.21	$56.11	$57.46	$59.35	$60.96	**$60.41**	**$51.20**
Distribution	$55.77	$57.72	$59.74	$61.18	$63.19	$64.90	**$64.32**	**$61.05**

Comparison to Previous Study

Transmission: **-15.2%**
Distribution: **-5.1%**

These 2004 estimates are comparable to the costs provided in the present study. The differences in the costs may be attributed to the following factors:

- **Improvements on Allocation of Capacity-Related Projects**

  In the 2004 Marginal T&D Cost Estimates study, the Major projects were assumed to be 100% capacity-related even if only a portion of the project was capacity related.

  In 2007, the Transmission Projects department devised a template that categorized all major capital projects into investment reasons as part of the justification of the project. The categories explain what percentage of the project is capacity-related or has other investment reasons.

[8] The inflation percentages are taken from G911-1, issued 2009 05 19.

- **T&D Domestic Budgets**

  In the 2004 Marginal cost study, Transmission & Distribution domestic budgets were combined into one budget making it difficult to separate the costs between the two groups. Therefore, it was necessary to make assumptions on the appropriate allocation between the two components. The domestic budgets used in this study were provided in more detail, therefore making the allocation of costs more accurate.

References

[1] "Capital Expenditure Forecast (CEF09-1), 2009/10 – 2019/20", Transmission & Distribution, Manitoba Hydro, November, 2009.

[2] "Electrical Load Forecast, 2009/10 to 2029/30", Market Forecast, Manitoba Hydro, May, 2009.

[3] "Marginal Transmission and Distribution Cost Estimates", ,File 2-14A6 or 5-5A, System Planning Dept, Transmission Planning Division, Manitoba Hydro, Dec 14, 2004.

Appendix A

Appendix A

– Manitoba Hydro Net Electric Load Forecast, 2008/09 to 2029/30

Table 1

NET MANITOBA HYDRO ELECTRIC LOAD FORECAST
2008/09 - 2029/30

Fiscal Year	Net Firm Energy (GW.h)	Net Firm Energy Change (%)	Net Total Peak (MW)	Net Total Peak Change (%)	Load Factor (%)
2008/09 Actual	24262		4477		61.9%
Weather	-268		-153		
2008/09 Adjusted	23994		4324		63.3%
2009/10	24080	0.4%	4333	0.2%	63.4%
2010/11	24600	2.2%	4407	1.7%	63.7%
2011/12	25159	2.3%	4499	2.1%	63.8%
2012/13	25599	1.7%	4570	1.6%	63.9%
2013/14	26012	1.6%	4633	1.4%	64.1%
2014/15	26618	2.3%	4733	2.2%	64.2%
2015/16	26973	1.3%	4789	1.2%	64.3%
2016/17	27331	1.3%	4845	1.2%	64.4%
2017/18	27644	1.1%	4893	1.0%	64.5%
2018/19	27923	1.0%	4942	1.0%	64.5%
10 Year Avg.		1.5%		1.3%	
2019/20	28288	1.3%	5007	1.3%	64.5%
2020/21	28654	1.3%	5071	1.3%	64.5%
2021/22	29021	1.3%	5136	1.3%	64.5%
2022/23	29391	1.3%	5202	1.3%	64.5%
2023/24	29762	1.3%	5268	1.3%	64.5%
2024/25	30136	1.3%	5334	1.3%	64.5%
2025/26	30516	1.3%	5401	1.3%	64.5%
2026/27	30899	1.3%	5469	1.3%	64.5%
2027/28	31285	1.3%	5537	1.3%	64.5%
2028/29	31674	1.2%	5606	1.2%	64.5%
2029/30	32066	1.2%	5675	1.2%	64.5%
21 Year Avg.		1.4%		1.3%	

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak

Appendix B

Appendix B

Table B.1	Analysis of the 2009/10 Transmission & Distribution Major Items
Table B.2	2009/10 Transmission Planning & Design Domestic Budget
Table B.3	2009/10 Distribution Planning & Design Domestic Budget
Table B.4	T&D Expansion Plan - Load Growth-Related Expenditures
Table B.5	2009/10 Marginal T&D (Avoided) Costs

Table B.1
Analysis of 2009/20 T&D Major Items in $1,000,000 (Constant 2009 CDN$)

Item	Justification	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Comments
Transmission - Major (100% load related)													
Winnipeg - Brandon Transmission System Improvements	Load & Reliability	1.4	1.6	3.4	3.6	5	21.7						To provide improvements to Western MB for future load growth
Transcona East 230-66KV Station	Load & Reliability	1.1	11	13.2	5.1								Required to supply increased load to East Winnipeg
Neepawa 230-66KV Station	Load & Reliability	1.1	14.1	9.5	5.1								To provide improvements to Neepawa & Western MB for future load growth
Pine Falls - Bloodvein 115KV Transmission Line	Load & Reliability		0.3	0.9	4.4	20.6	7.8						Required to supply increased load to Lake Winnipeg East area.
St. Vital - Steinbach 230 KV Transmission	Load & Reliability							0.8	0.9	2.6	6	9.6	To provide 230 KV in to the Steinbach areato support future load growth in South eastern MB.
Rosser Station 230-115 KV Bank 3 Replacement	Load & Reliability	2.6											To provide improvements on North Winnipeg & Selkirk 115KV for future load growth.
Transcona & Ridgeway Stations 66 kV Bus Upgrades	Load & Reliability	1.7	0.7										to replace existing overloaded ring bus.
Stanley Station 230-66 kV Transformer Addition	Load & Reliability				1.8	8.1	7.6	3.5					To improve voltage levels in the Morden/Winkler Area.
Wuskwatim - Transmission	Load & Reliability	90.1	30.5	18.9	0								The existing 230 kV transission system in Northern Manitoba does not have sufficient capacity to accommodate the additional output of the Wuskwatim Generating Station
Herblet Lake - The Pas 230 kV Transmission	Load & Reliability	41.9	30.4	7.2	1.9								The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads.
Firm Import Upgrades	Capacity, Reliablity & Import	4.8	0.6	2.1	2.1								Reconductor, resag transmission lines & Station work. This project will improve Manitoba Hydro's firm import capability during periods when we are expected to be energy deficient.
Transmission - Major (?% load related)													
Pointe du Bois - Transmission		9	26.3	10.4	20.6	13.9	3.1						To address aging infrastructure concerns with the existing 66 kV P Lines, provide adequate outlet transmission for future Pointe du Bois generating station expansion
(25% load related)	Load & Reliability	2.25	6.58	2.60	5.15	3.48	0.78						
Transcona Station - 66KV breaker replacement		0	3.6	1.8	0.6								The fault levels exceed 95% of the 9 existing breaker inerrupting ratings. A failure to these breakers can cause an outage to more than 10 000 customers.
(50% load related)	Reliability	0	1.8	0.9	0.3								
	Subtotal (Trans.)	**146.95**	**97.58**	**58.70**	**29.45**	**37.18**	**37.88**	**4.30**	**0.90**	**2.60**	**6.00**	**9.60**	
Distribution - Major (100% load related)													
Brereton Lake Station Area	Load & Reliability	0.3											A new station complete with a rebuilt distribution system will provide more acceptable customer service reliability
Martin New Outdoor Station	Load & Reliability	1	14.5	9.1	2.4								Install a new 3 bank outdoor station complete with 18 feeder positions and protection to replace the existing Martin station
Frobisher Station Upgrade	Load & Reliability	4.4											Replacing 2 existing transformers along with associated station material.
William New 66 kV-12 kV Station	Load & Reliability	0.5	3.6	3.1	2.9								Build a new two bank 66 kV-12 kV indoor station, complete with 10 feeder positions and protection to replace the Alfred and Charles stations
Waverley West Sub Division Supply - Stage 1	Load & Reliability	4.4											Install 20MVA capacity complete with pad mounted voltage regulators, 24 kV-2400 kVAR capacitor banks
York Station	Load & Reliability	2	1.8	0.1									Add a transformer bank and switchgear for nine feeder positions. alleviates loading problems at King station and interim relief at Sherbrook, and provides for future new loads
Brandon Crocus Plains 115-25 kV Bank Addition	Load & Reliability	0.6	3.1	1.9	0.6								To supply the load growth and the industrial loads in the south Brandon area
Perimeter South Station Distribution Supply Centre Installation	Load & Reliability	0.4	2										This option addresses the non-firm capacity issues
Niverville Station 66-12 kV Bank Replacements	Load & Reliability	2.6											This project was initiated as last year's peak load readings indicated that the capacity of this station has been exceeded
Distribution - Major (?% load related)													
Burrows New 66 kV-12 kV Station		9.1	12.2	5									Build a new two bank 66 kV-12 kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations
(25% load related)	Load & Reliability	2.28	3.05	1.25									
St. James 24 kV System Refurbishment		1.3	14.1	31.6	18.9								Terminate a new 24 kV Feeder (J54) at the St. James station to supply the Winnipeg Airport Authority load expansion
(75% load related)	Load & Reliability	0.98	10.58	23.70	14.18								
Shoal Lake New 33-12.47 kV DSC		3.2											Build a two bank Distribution Supply Centre (DSC) and rebuild and convert the town distribution system
(75% load related)	Load & Reliability	2.4											

Item	Justification	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Comments
Cromer Station and Reston RE12-4 25 kV Conversion		4.3	3	0.1	1.2								A new five mile feeder and 25 kV feeder conversion is required at Reston to address the increased demand due to oilfield exploration.
(80% load related)	Load & Reliability	3.44	2.4	0.08	0.96								
Winkler Market Feeder M25-13 Conversion		0.8											The load growth in the Winkler area is above Manitoba's average. The load has also caused feeder end voltage levels to fall & The increased load current has made it increasingly difficult to protect the 8 kV feeder
(30% load related)	Load & Reliability	0.24											
	Subtotal (Dist.)	25.53	41.03	39.23	21.04								
Other Major Items (0% load Related)													
Stanley Station 230-66 kV Hot Standby Installation	Reliability	4.9	1.2										To maintain voltage levels in the Morden/Winkler Area until the perminant transformer is to be installed in 2013.
Rosser - Inkster 115 KV Transmission	Reliability	3.3	1.4										To alleviate Contingency issues on the St.James to Tylehurst 115Kv cable in the event of the failure of the existing circuit.
Communication System - Southern MB (Great Plains)	Reliability	2.4											Required to provide continuous supply of reliable power to all of Manitoba Hydro's customers.
Communications Upgrade Winnipeg Area	Reliability	0.7											This project will provide more secure communications and replace cable that is nearing the end of useful life.
Pilot Wire Replacement	Reliability	1.3	1.4										The current equipment is no longer manufactured or supported by vendors.
Transmission Line Protection & Teleprotection Replacement	Reliability	1.4	6.1	6.1	2.3	1.1	0.9						To repair and restore existing failed teleprotection equipment
Winnipeg Central Protection Wireline Replacement	Reliability	2.5	0.6										This project minimizes or eliminates the need for hazardous work adjacent to high voltage cables
Mobile Radio System Modernization	communication	0.3	2.5	9.2	10.6	8							Replace the VHF mobile radio system with a modern digital system of increased capability.
Cyber Security Systems	security	3.6	0.4										Install or upgrade security and network systems for secure remote access, industrial data network installations, and compliance to NERC standards CIP-002-1 to CIP-009 1.
Site Remediation	safety	1.3	3.8	1.1									standards applicable to unrestricted use of abandoned former diesel sites, the sites must be investigated, remediated, and restored to equivalency of the surrounding area.
Oil Containment	safety	0.9	0.5										Design and construct oil containment systems to collect and recover any oil spilled within the system.
Station Battery Bank Capacity & System Reliability Increase	Reliability	5.3	4.7	6.4	6.4	6.6	6.3						Replace and/or upgrade battery bank capacity and chargers in 156 transmission and distribution stations and seven stand-alone communications sites to meet the NERC battery bank sizing criteria.
Transmission Line Re-Rating	Load,Safety & Reliability	3.2	0										To increase ground clearances to allow higher conductor temp. under all heavy current line loads.
Dorsey 500 kV R502 Breaker Replacement	Reliability	2.3	0.2										Existing breaker beyond its life cycle.
Birtle South - Rossburn 66 kV Line	Reliability					0.1	0.3	4.5					This new line will increase reliability for the Birtle South 230-66 kV station area by reducing the occurrence of line outages.
Neepawa North Feeder NN12-2 & Line 57 Rebuild	Reliability	1.9											Rebuild the main portion of feeder NN12-2 and a 16 km section of line 57
Winnipeg Central District Oil Switch Project	Reliability & safety	1.8											Replace the existing oil switches with pad mounted switch gear
Stony Mountain New 115 - 12 kV Station	Load & Reliability	0.7											The station equipment and supply lines are in a deteriorated condition and must be replaced. Load forecasts indicate Stony Mountain will also require a capacity increase
Defective RINJ Cable Replacement	Reliability	0.5	2.6										Replace approximately 62,500 metres of underground distribution 5kV and 15kV copper rubber insulated neoprene jacketed (RINJ) concentric neutral cable.
Rover Substation Replace 4 kV Switchgear	Reliability	0.4	3.3	3.9									Upgrade the existing switchgear.
Winnipeg Central District Underground Network Asbestos Removal	Safety	0.7											Remove or encapsulate asbestos wrap from high voltage cables currently present in approximately 1,800 manholes within the central Winnipeg area
Winnipeg Distribution Infrastructure Requirements	Reliability & Safety	1.7											Complete assessment and emergency replacement as required of distribution underground equipment in the City of Winnipeg, including plant previously associated with Winnipeg Hydro.
Dorsey - US Border New 500kV Transmission Line	Import & Export		0.5	1.9	8.2	17.6	32.4	79.3	64.8				Manitoba Hydro has received transmission service requests for more than 750 MW of new import and export service between the U.S. and Manitoba
Riel 230/500 kV Station	Reliability	36.1	58.4	79.6	45.1	38.2	4.6						The sectionalization of the 500 kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.
Bipole 3	Reliability	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	159.9			Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage
Subtotal (Non-load related)		**93.8**	**109**	**144.9**	**186**	**338.1**	**464.7**	**711.5**	**622.7**	**159.9**			
Domestic Budget													
Customer Service & Distribution Domestic	Load, Reliabilty, Safety	115.9	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135	137.7	140.5	This program consists of projects whose individual costs are of a relatively small amount
Transmission Domestic	Load, Reliabilty, Safety	29.6	30	30.6	31.2	31.8	32.4	33.1	33.8	34.4	35.1	35.8	This program consists of projects whose individual costs are of a relatively small amount

Note: Some Major projects were removed because it didn't pertain to load growth.

Table B.2
2009/2010 Transmission Planning & Design Domestic Budget

Project Type		Net Actual Costs
Customer Service		
	Capacity Enhancement	26,509
	New Connection	179,540
	Overhead Subdivision	0
Reliabilty - Import/Export Related		
	New/Increased General Delivery	52,388
	Transmission Service Delirvery	53,423
Reliabilty - Load Related		
	Capacity Enhancement	2,273,524
	New/Increased General Delivery	165,704

	(A)
Total	2,751,088

	(B)
Transmission Domestic Budget for 09/10:	$29,600,000
Capacity Related Portion (A/B):	**9.3%**

Table B.3

Distribution Planning & Design Annual Domestic Budget - 2009/2010 (Constant 2009 CDN$)

Project Type		BRANDON	SELKIRK	WINNIPEG	Total Sum of Net Annual Plan	Capacity Related Portion	
		Net Annual Plan	Net Annual Plan	Net Annual Plan		%	Net Gross
Customer Driven System Improvement							
	COMMERCIAL & SUBDIVISIONS	1,334,100	1,080,200	2,042,300	4,456,600	100%	$4,456,600
	HIGHWAY CHANGES	1,100,900	17,400	123,400	1,241,700	0%	$0
	MUNICIPAL AUTHORITY	-	-	147,900	147,900	0%	$0
Customer Sevice							
	4 PARTY URD*	194,300	639,400	3,122,000	3,955,700	75%	$2,966,775
	COMMERCIAL SERVICES	1,984,600	1,199,200	6,333,200	9,517,000	100%	$9,517,000
	PRELIMINARY ENGINEERING	235,200	406,300	252,700	894,200	0%	$0
	RESIDENTIAL SUBDIVISION	151,900	1,101,800	211,200	1,464,900	100%	$1,464,900
	STREETLIGHTING	75,200	56,100	419,700	551,000	0%	$0
System Improvement							
	AGING INFRASTRUCTURE	2,117,000	5,171,600	4,903,910	12,192,510	0%	$0
	OPERATIONAL ENHANCEMENT & RELIABILITY	1,903,617	820,200	4,635,783	7,359,600	0%	$0
	SAFETY	309,500	1,743,300	965,400	3,018,200	0%	$0
	VOLTAGE & GENERAL LOAD GROWTH	2,647,700	6,359,100	1,930,400	10,937,200	100%	$10,937,200

*** -** 25% of the cost in 4 party Underground Rural Distribution (URD) is the installation of Gas, MTS & TV

	(A)		(B)
Total:	55,736,510		$29,342,475

Capacity Related Portion (B/A): **52.6%**

Notes:
The following assumption can be made according to the above results:
- the Domestic Budget can be split between capacity and non-capacity related issues at a ratio of 50/50.

Table B.4

2010/20 T&D Expansion Plan - Load Growth-Related Expenditures in $1000 (Constant 2009 CDN$)

		Transmission				Distribution					
k	Fisical Years	Transmission Domestic Budget	Major [1]	Domestic	Total Capacity-Related	Customer Service & Dist. Domestic Budget	Distribution Domestic Budget	Major [2]	Domestic	Total Capacity-Related	Total Capacity-Related T & D
				(A) x 10%	(B)+(C)		(E)x50%		(F)x50%	(G)+(H)	(D)+(I)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
0	2009/10	29,600	146,950	2,960	149,910	115,900	57,950	25,530	28,975	54,505	204,415
1	2010/11	30,000	97,575	3,000	100,575	117,500	58,750	41,025	29,375	70,400	170,975
2	2011/12	30,600	58,700	3,060	61,760	119,900	59,950	59,230	29,975	89,205	150,965
3	2012/13	31,200	29,450	3,120	32,570	122,300	61,150	41,035	30,575	71,610	104,180
4	2013/14	31,800	37,000	3,180	40,180	124,700	62,350	51,705	31,175	82,880	123,060
5	2014/15	32,400	37,875	3,240	41,115	127,200	63,600	51,705	31,800	83,505	124,620
6	2015/16	33,100	67,925	3,310	71,235	129,800	64,900	51,705	32,450	84,155	155,390
7	2016/17	33,800	67,925	3,380	71,305	132,400	66,200	31,705	33,100	64,805	136,110
8	2017/18	34,400	67,925	3,440	71,365	135,000	67,500	31,705	33,750	65,455	136,820
9	2018/19	35,100	67,925	3,510	71,435	137,700	68,850	31,705	34,425	66,130	137,565
10	2019/20	35,800	67,925	3,580	71,505	140,500	70,250	31,705	35,125	66,830	138,335

Notes:

1 - Years 6 to 10 were revised by taking the average of years 0-5 (67,925,000) as stated in section 7.4.2 of the report.

2 - Years 4 to 10 were revised by taking the average of years 0-3 ($31,705,000) as stated in section 7.4.2 of the report.

Table B.5

2009/10 Marginal T&D (Avoided) Costs ($/KW/Year)

Discount Rate= 5.75%
Avg load Growth (MW)= 67 (A)
1-Year Deferral Factor = 0.05437352 (E)

Fiscal Year	K	Transmission Capacity-Related Costs ($1000)	Distribution Capacity-Related Costs($1000)	Present Worth of Trans. Cost($1000) (B)	Present Worth of Dist. Cost ($1000) (C)	Present Worth Factors (D)
2010/11	1	100,575	70,400	95,106	66,572	0.9456
2011/12	2	61,760	89,205	55,226	79,768	0.8942
2012/13	3	32,570	71,610	27,541	60,553	0.8456
2013/14	4	40,180	82,880	32,128	66,272	0.7996
2014/15	5	41,115	83,505	31,088	63,141	0.7561
2015/16	6	71,235	84,155	50,934	60,172	0.7150
2016/17	7	71,305	64,805	48,212	43,817	0.6761
2017/18	8	71,365	65,455	45,629	41,850	0.6394
2018/19	9	71,435	66,130	43,190	39,983	0.6046
2019/20	10	71,505	66,830	40,882	38,209	0.5717

	(B)	(C)	(D)
Total SUM	469,939	560,338	7.4481

Total Avoided Cost	
(E) x ((B) or (C)) / (A) x (D)	
Transmission	Distribution
$51.20	**$61.05**

One Year Deferral(OYD) Equation

$$C_{avoid} = \overbrace{\left(1-\frac{1}{1+i}\right)}^{E}\overbrace{\left[\sum_{k=1}^{N}\frac{I_k}{(1+i)^k}\right]}^{B \text{ or } C} \Bigg/ \left[\overbrace{\Delta L_{ave}}^{A}\overbrace{\sum_{k=1}^{N}\frac{1}{(1+i)^k}}^{D}\right]$$

Appendix C

Appendix C

Table C.1
Split of 2003/04 TP&D and DP&D Domestic Budget (Constant 2004 CDN$)

		Approved Domestic Budget (in$1000)			Capacity-Related Portion (in $1000)		
		Blanket	Non-blanket	Total (A) + (B)	Blanket	Non-Blanket	Total (D) + (E)
		(A)	(B)	(C)	(D)	(E)	(F)
(R1)	Transmission	1,132	6,825	7,957	0	1,784	1,784
(R2)	Subtransmission - TP&D	1,132	2,319	3,451	0	2,213	2,213
(R3)	Subtransmission - DP&D	2,761	3,898	6,659	2,071	1,846	3,917
(R4)	Distribution	22,087	8,805	30,892	15,150	4,045	19,195
(R5)	Total Transmission (R1+R2)	2,264	9,144	11,408	0	3,997	3,997
(R6)	Total Distribution (R3+R4)	24,848	12,703	37,551	17,221	5,891	23,112
(R7)	Total Approved T&D Domestic Budget (R5 + R6)			48,959			
(R8)	Total Capacity-related T&D Domestic Budget (R5 + R6)						27,109
(R9)	Capacity-related Portion (R6/R5)						55.4%
Split of Capacity-related domestic budget							
	Transmission (R5/R8)						14.7%
	Distribution (R6/R8)						85.3%

Notes:

1).The balances of targets are not included in the analysis

2). The following assumptions may be made according to the above results:

a). The domestic budget may be split between capacity and non-capacity related portions at a ratio of 50/50

b). Capacity-related domestic budget may be split as follows:

15% Transmission

85% Distribution

3). Effect of inflation is included

4). All Domestic & Budget Costs are aquired fro the 2004 Marginal Cost Study, SPD 04/05.

Table C.2

2004 T&D Revised Expansion Plan - Load Growth-Related Expenditures in $1000 (Constant 2004 CDN$)

k	Fisical Years	T&D Domestic Budget	TP&D and DP&D Domestic Budget	Capacity-related Domestic Budget	Transmission Major	Transmission Domestic	Transmission Total Capacity-Related	Distribution Major	Distribution Domestic	Distribution Total Capacity-Related	Total Capacity-Related T & D
			(A) x75%	(B)x55%		(C) x 15%	(B)+(C)		(C)x85%	(G)+(H)	(H)+(K)
		(A)	(B)	(C)	(D)	(G)	(H)	(I)	(J)	(K)	(L)
0	2004/05	81,300	60,975	30,488	526	4,573	5,099	0	25,914	25,914	31,014
1	2005/06	81,471	61,103	30,552	2,529	4,583	7,112	0	25,969	25,969	33,081
2	2006/07	81,795	61,346	30,673	8,722	4,601	13,323	1,187	26,072	27,259	40,582
3	2007/08	81,888	61,416	30,708	19,018	4,606	23,624	6,866	26,102	32,968	56,592
4	2008/09	82,130	61,598	30,799	29,828	4,620	34,448	6,053	26,179	32,232	66,680
5	2009/10	82,240	61,680	30,840	34,745	4,626	39,371	12,388	26,214	38,602	77,972
6	2010/11	82,670	62,003	31,001	44,960	4,650	49,610	4,075	26,351	30,426	80,037
7	2011/12	81,484	61,113	30,557	42,583	4,583	47,166	0	25,973	25,973	73,140
8	2012/13	80,484	60,363	30,182	11,857	4,527	16,384	0	25,654	25,654	42,039
9	2013/14	81,667	61,250	30,625	24,262	4,594	28,856	0	26,031	26,031	54,887

Notes:

1.) The Subtransmission Domestic & major projects were split up into Transmission & Distribution Budgets accordingly
2.) Column B - 75% of the T&D Domestic Budget is associated with Plannning & Design (as stated in the 2004 Marginal Cost Study)
3.) All Major, Domestic & Budget Costs are aquired fro the 2004 Marginal Cost Study, SPD 04/05.

Table C.3
2004 Revised Maginal T&D (Avoided) Costs ($/KW/Year)

Discount Rate= 6.00%
Avg load Growth (MW)= 30 (A)
1-Year Deferral Factor = 0.056603774 (E)

Fiscal Year	K	Transmission Capacity-Related Costs ($1000)	Distribution Capacity-Related Costs($1000)	Present Worth of Trans. Cost($1000) (B)	Present Worth of Dist. Cost ($1000) (C)	Present Worth Factors (D)
2005/06	1	7,112	25,969	6,709	24,499	0.9434
2006/07	2	13,323	27,259	11,857	24,261	0.8900
2007/08	3	23,624	32,968	19,835	27,680	0.8396
2008/09	4	34,448	32,232	27,286	25,530	0.7921
2009/10	5	39,371	38,602	29,420	28,845	0.7473
2010/11	6	49,610	30,426	34,973	21,449	0.7050
2011/12	7	47,166	25,973	31,368	17,274	0.6651
2012/13	8	16,384	25,654	10,280	16,096	0.6274
2013/14	9	28,856	26,031	17,080	15,408	0.5919

	(B)	(C)	(D)
Total SUM	188,809	201,042	6.8017

Total Avoided Cost
(E) x ((B) or (C)) / (A) x (D)

Transmission	Distribution
$52.38	**$55.77**

One Year Deferral(OYD) Equation

$$C_{avoid} = \overbrace{\left(1-\frac{1}{1+i}\right)}^{E}\left[\overbrace{\sum_{k=1}^{N}\frac{I_k}{(1+i)^k}}^{B\text{ or }C}\right] \Big/ \left[\overbrace{\Delta L_{ave}}^{A}\overbrace{\sum_{k=1}^{N}\frac{1}{(1+i)^k}}^{D}\right]$$

Manitoba Hydro

TRANSMISSION PLANNING & DESIGN DIVISION

SYSTEM PLANNING DEPARTMENT

REPORT ON

MARGINAL TRANSMISSION & DISTRIBUTION COST ESTIMATES

SPD 04/05

PROVINCE OF MANITOBA
X. LI
Xin Li
04-12-14
REGISTERED PROFESSIONAL ENGINEER

PREPARED BY: Xin Li, Ph.D., P. Eng.

REVIEWED BY: Garry Zielke, P.Eng. G Zielk 14 Dec 04

✓ (1) Report for Information or
(2) ~~Recommended For Implementation~~

DEPARTMENT:

DIVISION:

DATE: December 14, 2004

FILE NO.: 2-14A6 or 5-5A

DISTRIBUTION:

Executive
M. Snyder (CPJ)
G.W. Rose (CPJ) (if req'd)
K.R.F. Adams (CPJ)(if req'd)

Transmission Planning & Design Division
G.H. Neufeld
C. Steele
G. Allard

Power Planning & Development Division
E. Wojczynski
M.C. Saxton
H.M. Surminski

Rates & Regulatory Affairs Division
K.R. Wiens

Transmission System Operations Division
T.E. Tymofichuk
L.E. Midford
B.A. Poff
G.T. Arnason

Distribution Planning & Design Division
R.F. Dacombe
G. Buchanan
P.P.M. Mathew
R.Q. Boychuk
D.K. Solkoski
E.H. Wiebe

Customer Service Operations Dividion
M.P. Dudar (CPJ) (if req'd)

Apparatus Maintenance Division
W.M. DeJaegher

Trans Construction & Line Mtce Division
L.T. Moffat

Others
A. M. Snyder (CPJ)
C.E. Wray (CPJ)
C. Mazur (CPJ)

Contents

Executive Summary

Objectives

This report has the following two objectives:

1) To develop a methodology for estimating marginal (or avoided) T&D costs.
2) To update the existing marginal (or avoided) T&D costs that were originally produced in the 1990 avoided cost study [4,5,7].

Recommendations

1) **The one year deferral (OYD) method should be used for marginal (or avoided) T&D cost estimates.**

   This method is developed on the basis of the deferral value of load-growth related capital costs due to a reduction in the forecasted system peak load (demand). In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth. The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecast annual peak load.

2) **The values in Table A should be used as long-term marginal (or avoided) T&D cost components.**

TABLE A

LEVELIZED MARGINAL (OR AVOIDED) T&D COSTS ($/KW/YEAR)*

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average (Mean)	45.44	22.09	40.93
Standard Deviation	6.19	2.12	1.60

***Notes:**

a) The values are levelized over the study period of 2004/05 to 2013/14.

b) The values are expressed in 2004 constant dollars and escalate at the inflation rate.

c) The averages (means) are considered as the generic marginal T&D cost components. The probability that the marginal cost falls within 1, 2, and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively.

d) The values are valid for a winter peak system.

e) The values are non-area-specific (i.e., do not vary by area).

f) The values do not include the replacement costs associated with the capital investments.

g) The values can be assumed to continue into the future beyond the planning horizon of 2013/14.

h) Although the values are derived for load reductions between 0 and 1 year's worth of load growth, it has been shown that their application can be extended to the case of larger load reductions (say, up to two times the annual load growth).

i) The values are valid for a real discount rate of 6.0% (without the inflation rate component). If the real discount rate is significantly different from 6.0%, they should be modified using the information provided in this report.

j) The values are valid only for transmission, subtransmission and distribution-circuit defined in this report.

The costs are based on the "T&D Capital Expenditure Forecast (CEF03-1)" for the period of 2003/04 to 2013/14 and the Corporate "Electric Load Forecast" for the same period. They are derived using the OYD method and a random load reduction stream that is defined as $\{\delta L_k\} = \{\lambda_k \Delta L_k\}$, where ΔL_k ($k = 1,2,3,\cdots$) is the forecasted load growth in year k and λ_k ($k = 1,2,3,\cdots$) is a random number uniformly distributed between 0 and 1.

3) **The marginal costs should be updated 5 years from now or earlier as needed.**

Results of Pevious Study

The last avoided T&D cost study was conducted in 1990. The avoided cost components produced in that study are $11/kW/Year and $11/kW/Year (in 1990 constant dollars) for transmission and distribution, respectively. They are significantly lower than those recommended in the present study. This is mainly attributed to the differences in the methods, assumptions and data used for the avoided cost estimates.

1. Introduction

For various purposes such as the evaluation of demand side management (DSM) programs and equipment losses, etc. [4,7], we need to estimate the additional (incremental) cost incurred by an increase in capacity and energy requirements, or equivalently the cost that can be avoided if not having to increase capacity and energy requirements. Such an incremental cost is labeled “marginal cost” or “avoided cost”. The marginal cost for a power system is usually split into three system levels: generation, transmission and distribution (T&D). The marginal generation costs include both capacity and energy components; while the marginal T&D costs are capacity related only.

The term “avoided cost” was replaced by “marginal cost” in the report on “1996/97 Update to Marginal Costs”, PP&O Report 97-5, prepared by Resource Planning & Market Analysis because the latter was judged to be more descriptive and useful for the Manitoba Hydro situation [7]. To be consistent with the current marginal costing practices, the term “marginal cost” was adopted in this report. The term “avoided cost”, however, will occasionally be used for convenience, bearing the same meaning as “marginal cost”.

In this report, we will first propose a methodology for marginal T&D costs, and then provide marginal (or avoided) T&D cost estimates for the Manitoba Hydro system. The results will supercede the existing avoided T&D costs originally produced in the 1990 avoided cost study [4].

2. Methodology

Marginal T&D cost seems to be a simple concept, but its detailed definitions and calculation procedures vary widely in practice depending upon the way it is perceived [1,2,4,6,8,9,10]. The marginal (or avoided)

T&D costs currently used in Manitoba Hydro are based on the deferral values, i.e. the savings from capital cost deferrals in response to a reduction in the forecasted system peak load (demand). A similar definition has been used by other utilities/organizations such as PG&E, Energy and Environmental Economics, Inc., San Francisco, CA, etc. [8,9,10] as well. In this study, we will use the deferral concept and seek a methodology for marginal T&D costs with respect to small load reductions, say, close to the average annual load growth or smaller.[1]

2.1. Notations

For convenience, the notations to be used in this report are summarized below:

k – fiscal year with $k=0$ representing the current one.

N – study period in years based on which the marginal costs are estimated, which covers the future years within the T&D planning horizon (about 10 years) if not otherwise indicated.

j – inflation rate or escalation rate.[2]

i – real discount rate, i.e., discount rate without the effect of inflation.[3]

d – discount rate with the effect of inflation,[4] which is determined as

$$d=(1+i)(1+j)-1=i+j+ij \tag{1}$$

I_k – load-growth related investments (capital expenditures) for year k expressed in terms of "constant-worth" dollars, which do not

[1] In the existing Manitoba Hydro avoided costing method [4], load reductions are required to be significant enough to cause capital deferrals.

[2] j is taken to be the inflation or escalation rate in the document "Projected Escalation, Interest and Exchange Rates — G911-1", issued 2004 05 27.

[3] i is taken to be the real weighted average cost of capital in G911-1, issued 2004 05 27.

[4] d is taken to be the weighted average cost of capital in G911-1, issued 2004 05 27.

escalate with time. Note that “load-growth related” is used to describe the investments driven by the needs for capacity expansion to accommodate the forecasted load growth.

$\tilde{I}_k$ – load-growth related investments for year k expressed in terms of “then-current” dollars (including the effect of inflation). $\tilde{I}_k$ and I_k are related to each other as

$$\tilde{I}_k = I_k (1 + j)^k \tag{2}$$

I_{eq} – equivalent uniform annual investments expressed in “constant-worth” dollars over the study period, i.e.

$$I_{eq} = [\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{1}{(1+i)^k} \tag{3}$$

L_k – forecasted system peak load (demand) for year k.

ΔL_k – load growth in year k, which is defined as

$$\Delta L_k = L_k - L_{k-1} \tag{4}$$

ΔL_{ave} – average annual load growth over the study period, i.e.

$$\Delta L_{ave} = \frac{1}{N} \sum_{k=1}^{N} \Delta L_k \tag{5}$$

δL_k – expected reduction in the peak load in year k.

Δt_k – deferral time, i.e. a time period by which the capital expenditures for year k are deferred.

Δt – deferral time that does not vary from year to year.

I_{incr} – levelized incremental investment per unit of load growth ($/kW/Year).

C_{avoid} – levelized marginal (or avoided) cost ($/kW/Year).

2.2. General Deferral Concept

The deferral concept to be presented below is similar as the one used in the previous avoided cost study [4], which is on the basis that the load-growth related capital expenditures can be deferred if there is a reduction in the forecasted system peak load (demand).

Suppose the capital expenditures for year k, denoted by $\tilde{I}_k$, can be deferred by a time period, Δt_k, due to a load reduction, δL_k. The capital expenditures deferred to year $k+\Delta t_k$, after being adjusted for inflation, are equal to

$$\tilde{I}_k(1+j)^{\Delta t_k}$$

This amount of dollars is discounted back to year k as

$$\frac{\tilde{I}_k(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}$$

This indicates that the deferring of $\tilde{I}_k$ to year $k+\Delta t_k$ is equivalent to the spending of $\tilde{I}_k(1+j)^{\Delta t_k} / (1+d)^{\Delta t_k}$ in year k. Obviously, the saving (i.e. cost avoided) in year k is

$$\tilde{I}_k - \tilde{I}_k \frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}} = [1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\tilde{I}_k$$

The deferral value, i.e., the present value of all savings over the study period, is

$$\Delta PV = \sum_{k=1}^{N}[1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\frac{\tilde{I}_k}{(1+d)^k} \qquad (6)$$

Such a deferral value is also used in the Present Worth (PW) method [2,8,10].

Considering the relations $(d+1)=(1+i)(1+j)$ and $\tilde{I}_k = I_k(1+j)^k$, we can rewrite Eq. (6) as

$$\Delta PV = \sum_{k=1}^{N}[1-\frac{1}{(1+i)^{\Delta t_k}}]\frac{I_k}{(1+i)^k} \tag{7}$$

The deferral value, ΔPV, can be levelized over the study period to yield the marginal (or avoided) cost, as described below.

When the effect of inflation is not accounted for, the marginal (or avoided) cost ($/kW/Year), denoted by C_{avoid}, can be assumed to be constant over the study period. The present value of the costs avoided due to load reductions is

$$\sum_{k=1}^{N}\frac{C_{avoid}\delta L_k}{(1+i)^k}$$

This value should exactly match the deferral value, ΔPV, determined by Eq. (6) or (7). Therefore, the levelized marginal cost is

$$C_{avoid} = \{\sum_{k=1}^{N}[1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\frac{\tilde{I}_k}{(1+d)^k}\}\Big/\sum_{k=1}^{N}\frac{\delta L_k}{(1+i)^k} \tag{8}$$

or equivalently

$$C_{avoid} = \{\sum_{k=1}^{N}[1-\frac{1}{(1+i)^{\Delta t_k}}]\frac{I_k}{(1+i)^k}\}\Big/\sum_{k=1}^{N}\frac{\delta L_k}{(1+i)^k} \tag{9}$$

Equations (8) and (9) provide two equivalent approaches to arrive at the marginal cost, i.e., the “then-current” dollar approach and the “constant-worth” dollar approach.[5] In both equations, the load reduction is discounted at the real discount rate, i. Equation (9) is easier to handle and therefore will be used hereafter in this report.

The levelized marginal costs (or avoided) cost C_{avoid} determined by Eq. (8) or (9) is measured in constant-worth dollars. It can be converted to the "then-current" dollar value in year k as $C_{avoid}(1+j)^k$.

The two methods to be presented in the following sections are derived from the above concept. Their difference lies mainly in the restrictions imposed on the deferral time.

2.3. Load Reduction Streams

In the context of this report, a load reduction stream refers to a series of reductions in peak load (demand), which is represented mathematically as $\{\delta L_1, \delta L_2, \cdots, \delta L_N\}$. The marginal cost is affected by the type (shape) of load reduction stream. In this study, the following three types of load reduction streams will be considered:

- *Uniform load reduction stream*: It is defined such that the reduction in peak load is the same from year to year, i.e. $\delta L_k = \delta L$ for $k = 1, 2, 3, \cdots, N$.
- *Near-uniform load reduction stream*: It is defined such that its shape is similar to that of the annual load growth stream, i.e. $\delta L_k = \lambda \Delta L_k$ ($k = 1, 2, 3, \cdots, N$), where λ is a number between 0 and 1. Since the annual load growth usually does not deviate significantly from the average, this type of load reduction stream is referred to as near-uniform load reduction stream in this report.
- *Random load reduction stream*: It is defined such that the reduction in peak load varies from year to year in a random fashion. It is mathematically represented as $\{\delta L_k\} = \{\lambda_k \Delta L_k\}$ where λ_k ($k = 1, 2, 3, \cdots, N$) is a random number uniformly distributed between α and 1 with α being

[5] The "then-current" dollars include the effect of inflation, but the "constant-worth" dollars don't. The constant dollar cash flows can be brought forward or deferred without adjustment for inflation. For more detailed information, see Section 3.8.6 Inflationary Effects in "Principles of Engineering Economic Analysis" by A.J. Szonyi, et al. [3]. In Manitoba Hydro, "constant-worth dollar" is usually referred to as "constant dollar".

a fixed positive number smaller than 1. It covers all the possible types of load reduction streams in practice, including the above two types.

2.4. One-Year Deferral (OYD) Method

The method to be presented below may be viewed as a probability-based one. In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth.[6] The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecasted annual peak load.

Let us start with an example. Suppose the capacity of a substation is 40 MWA, the power factor is 1.0, and the expected peak loads of the station are 38.5 MW and 41.2 MW for 2010/11 and 2011/12, respectively. The expected load growth in 2011/12 at this station is 2.7 MW. The existing station capacity can meet the 2010/11 peak load but can not meet the 2011/12 one. The shortage or scarcity of capacity for 2011/12 is 1.2 MW, as shown in Fig. 1. Based on the above information, a new transformer has been planned for service in 2011/12. Now, a reduction of 1.5 MW in the peak load, for instance, is expected for 2011/12. Considering that the load reduction of 1.5 MW exceeds the capacity shortage of 1.2 MW for 2011/12, we can defer the installation of the new transformer from 2011/12 to 2012/13. This suggests that the load reduction needs not to reach at least one year's worth of load growth of 2.7 MW in order to cause a capital deferral*!*

[6] In the approach used in the previous avoided cost study [4,5], it is assumed that a reduction in load can not cause capital deferrals until it approaches a significant level. "Significant" is defined such that the size of load reduction reaches at least one-year load growth. Under such an assumption, we can not estimate the avoided costs due to small load increments. Besides, it is hard to obtain accurate avoided cost estimates unless the load reductions are chosen such that they are just "significant". As shown in this section, the "significant level" requirement is inconsistent with the practical situation.

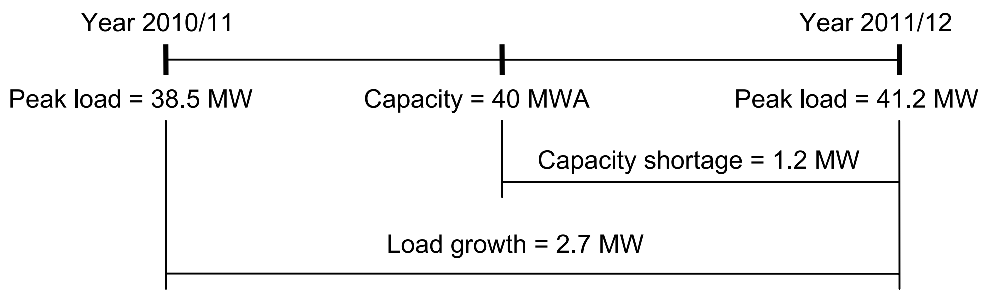


Fig. 1. Illustration of capacity shortage of a substation that is unable to accommodate the peak load in the year of 2011/12, assuming that the power factor is 1.0.

From a system-wide standpoint, the investments for year k are associated with capacity expansion of many facilities (e.g. lines, stations, etc.). The capacity shortage of each one could be anywhere between 0 and the annual load growth, ΔL_k. In other words, the capacity shortage is randomly distributed between 0 and ΔL_k. According to what has been observed from the above example, any load reduction, δL_k, even if it is less than ΔL_k, could possibly cause a capital deferral. Now the question is: What is the probability of capital deferral due to a load reduction of δL_k? To answer this question, we would like to look at the following three situations:

- For $\delta L_k / \Delta L_k = 0$ (no load reduction), the probability of capital deferral is 0%.
- For $\delta L_k / \Delta L_k = 1$ (the load reduction equal to the annual load growth ΔL_k), the probability of capital deferral is 100%.
- For $\delta L_k / \Delta L_k = 0.5$ (the load reduction is halfway between 0 and ΔL_k), the probability of capital deferral is 50%, which is based on the judgment that there is an equal chance for the capacity shortage to be above or below $0.5\Delta L_k$.

The above observations suggest that the probability of capital deferral is $\delta L_k / \Delta L_k$, which is a linear function of δL_k.

Thus, out of the investments for year k, the portion that would be deferred by one year due to a load reduction, δL_k, is equal to $\frac{\delta L_k}{\Delta L_k} \times 100\%$.

The remaining portion is equal to $(1 - \frac{\delta L_k}{\Delta L_k}) \times 100\%$, which would not be deferred and therefore would not contribute to any savings. Replacing I_k and Δt_k in Eq. (9) with $I_k \, \delta L_k / \Delta L_k$ and 1, respectively, we immediately get

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{\delta L_k}{\Delta L_k} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{\delta L_k}{(1+i)^k} \tag{10}$$

where δL_k is between 0 and ΔL_k.

If δL_k in Eq. (10) is replaced with $\delta L_k \beta$ with β being an arbitrary number, the marginal cost C_{avoid} remains unchanged. This means that the marginal cost determined by Eq. (10) is not sensitive to the size of load reduction for a similar shape of load reduction stream.

Below we would like to briefly analyze the marginal costs for uniform and near-uniform load reduction streams. The situation for the random load reduction will be examined later in this report.

For a uniform load reduction stream (i.e., $\delta L_k = \delta L$), Eq. (10) reduces to

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{I_k}{\Delta L_k} \frac{1}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{1}{(1+i)^k} \tag{11}$$

For a near-uniform load reduction stream (i.e., $\delta L_k = \lambda \Delta L_k$), Eq. (10) becomes

$$C_{avoid} = [(1 - \frac{1}{1+i})\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{\Delta L_k}{(1+i)^k} \tag{12}$$

Numerical results presented later in this report show that the differences between the avoided costs for uniform and near-uniform load reduction streams are so small that they are interchangeable. Equations (11) and (12) do not contain δL_k. This means that the marginal costs for uniform and near-uniform load reduction streams do not vary with the size of load reduction.

From the Corporate "Electric Load Forecast", it is seen that the annual load growth usually does not deviate significantly from the average. For this reason, the denominator in Eq. (12) can be approximated by $\sum_{k=1}^{N} \Delta L_{ave} \big/ (1+i)^k$, that is,

$$\sum_{k=1}^{N} \frac{\Delta L_k}{(1+i)^k} \approx \Delta L_{ave} \sum_{k=1}^{N} \frac{1}{(1+i)^k} \tag{13}$$

For the data provided in Table 1 for example, $\sum_{k=1}^{9} \Delta L_k \big/ (1+i)^k = 202.45$ and $\sum_{k=1}^{9} \Delta L_{ave} \big/ (1+i)^k = 202.72$, noting that a discount rate of $i = 6.0\%$ is used for the calculations. The two numbers, 202.45 and 202.72, are almost identical. Thus, a good approximation of Eq. (12) is

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ [\Delta L_{ave} \sum_{k=1}^{N} \frac{1}{(1+i)^k}] \tag{14}$$

The above facts suggest that a uniform load reduction stream equal to the average annual load growth can be assumed to cause the entire investment plan to shift by one year. This is the very assumption adopted in the PG&E's PW method [9].

2.5. Arbitrary Deferral Time (ADT) Method

In the PW method [2,10], the deferral time, Δt_k, is defined as the ratio of peak load reduction to peak load growth, i.e., $\Delta t_k = \delta L_k / \Delta L_k$. If the deferral time is not restricted to integer values in years, it can be used to obtain the marginal cost for any small size of load reduction [8]. The PW method with such a relaxed definition of deferral time is renamed the arbitrary deferral time (ADT) method in this report for convenience. However, the justification of using a non-integer deferral time seems still to be in question. Below we attempt to explore the meaning of such a deferral time.

In Section 2.4 it has been shown that $\frac{\delta L_k}{\Delta L_k} \times 100\%$ of the investments, I_k, for year k would be deferred by one year ($\Delta t_k = 1$) due to a load reduction $\delta L_k \le \Delta L$, and $(1 - \frac{\delta L_k}{\Delta L_k}) \times 100\%$ of the investments would not be deferred ($\Delta t_k = 0$). The weighted average deferral time is

$$\Delta t_k = 0 \times (1 - \frac{\delta L_k}{\Delta L_k}) + 1 \times \frac{\delta L_k}{\Delta L_k} = \frac{\delta L_k}{\Delta L_k} \tag{15}$$

Thus, the effect of deferring $\frac{\delta L_k}{\Delta L_k} \times 100\%$ of the investment, I_k, by one year is equivalent to that of deferring 100% of the investments by a period of Δt_k with $\Delta t_k = \delta L_k / \Delta L_k$. The non-integer deferral time can therefore be interpreted as the weight average deferral time. Substituting $\Delta t_k = \delta L_k / \Delta L_k$ in Eq. (9) yields

$$C_{avoid} = \{ \sum_{k=1}^{N} [1 - \frac{1}{(1+i)^{\delta L_k / \Delta L_k}}] \frac{I_k}{(1+i)^k} \} \Big/ \sum_{k=1}^{N} \frac{\delta L_k}{(1+i)^k} \tag{16}$$

where δL_k is between 0 and ΔL_k.

Numerical tests later in this report show that Eq. (16) and (10) give practically the same results.

2.6. Incremental Investment per Unit of Load Growth

The present value of the annual investments over the study period is calculated as follows:

$$PV = \sum_{k=1}^{N} \frac{\widetilde{I}_k}{(1+d)^k} = \sum_{k=1}^{N} \frac{I_k}{(1+i)^k} \tag{17}$$

When not considering the effect of inflation, we may assume that the incremental investment per unit of load growth, denoted by I_{incr}, is constant over the study period. The present value of the annual investments driven by the load growth can be expressed as

$$PV = \sum_{k=1}^{N} \frac{I_{incr} \Delta L_k}{(1+i)^k} \tag{18}$$

This value should exactly match the one determined by Eq. (17). Thus, we have

$$I_{incr} = [\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{\Delta L_k}{(1+i)^k} \tag{19}$$

This is the levelized incremental investment per unit of load growth.

There exists an interesting relation between I_{incr} and C_{avoid} for uniform and near-uniform load reduction streams. Comparing Eq. (19) with (12), we have

$$C_{avoid} = (1 - \frac{1}{1+i}) I_{incr} \approx i I_{incr} \tag{20}$$

This equation indicates that the marginal cost is approximately equal to the carrying charge or opportunity cost of the incremental investment per unit of load growth for a uniform or near-uniform load reduction stream. This may be used as an alternative approach to estimate the marginal cost.

3. Data Preparation

The task of this section is to prepare the data for marginal T&D cost estimates, which include annual load growth rates, annual load-growth related capital expenditures, etc.

3.1. Assumptions

Summarized below are the assumptions used for the marginal T&D cost estimates:

- T&D facilities are sized to meet the winter peak load (demand).
- T&D marginal costs are not area-specific (i.e., do not vary by area).
- T&D marginal costs expressed in constant dollars will continue into the future beyond the 10 year planning horizon.
- The entire T&D system is equally affected by a load reduction on a percentage basis.
- The load-growth related investment plan contained in “T&D Capital Expenditure Forecast (CEF03-1), 2003/04 – 2013/14” [11] is assumed to meet winter system peak loads which are considered to be the net total peaks (MW) in the base-case scenario in “Electric Load Forecast, 2003/04 to 2023/24” [12].[7]

[7] The net total peak is defined as the maximum hourly demand in a given year, required to meet the needs of Manitoba customers on the integrated system. It does not include diesel generation, industrial self-generation, exports, losses associated with exports/imports, and station service loads.

- The Customer Service Orders are not relevant to the T&D avoided costs.[8]

Note that an item is said to be "capacity-related", "load-growth related" or "load-related" if it is driven by the needs for capacity expansion in order to accommodate the forecasted system load growth or to meet the forecasted system peak loads.

It is assumed that load-growth related capital costs can not be deferred due to a reduction in the forecast load in the following situations:

- They are already committed.
- Their in-service dates are dictated by factors other than load growth such as safety, etc.

3.2. Split of Marginal T&D Cost

The marginal T&D cost was split into transmission and distribution components in the last avoided cost study [4,5]. Transmission and distribution are defined as follows:

- *Transmission*: It includes assets for bulk transmission of power. Specifically, it consists of transmission lines and terminal stations.[9] Assets providing connections between generation and transmission are excluded because they are included in the evaluation of marginal generation costs.
- *Distribution*: It includes assets for delivering power from terminal stations to customers. In this report, distribution is further split into two components:

[8] Overhead transformers and secondary services (i.e. the portion of distribution from distribution transformers to customer meters, which are typically 347/600 V, 120/208 V, etc.) are for individual customers and the associated costs are usually covered by the Customer Service Orders (previously called District Work Orders). It is assumed that these costs can not be deferred by a DSM program, etc. and is not relevant to the avoided distribution cost.

[9] Terminal stations are defined as those providing connections between major transmission voltage levels (115 kV and above) or between major transmission and subtransmission voltage levels (66 kV, 33 kV).

- Subtransmission: It includes subtransmission lines and distribution stations.
- Distribution-circuit: It includes assets between distribution stations (exclusive) and customer meters (e.g. overhead lines, underground cables, pad-mounted transformers, etc.).

These cost components are additive.

3.3. Study Period

The latest T&D Capital Expenditure Forecast (CEF03-1) was issued in November 2003, and it covers the years 2003/04 to 2013/14. The fiscal year of 2003/04 has passed and therefore the capital costs for that year are "sunk", i.e. irrelevant to the marginal costs. So we will look at the fiscal years 2004/05 to 2013/14. Each fiscal year is identified by a number k ($k = 0, 1, 2, 3, \cdots, N$) with $N = 9$. The number $k = 0$ represents the current fiscal year of 2004/05. Considering that the capital expenditures for the current fiscal year can barely be deferred in practice, we will determine the marginal costs based on the study period of year 1 to 9 (i.e. 2005/06 to 2013/14).

It is recommended that the marginal T&D cost estimates based on the 9 year study period be updated in 5 years or earlier as needed.

3.4. Forecasted System Peak Loads

The forecasted total system peak loads for the years 2004/05 to 2013/14 are given in the Manitoba Hydro Electric Load Forecast 2003/04 to 2023/24 (referring to [11] or Appendix A). They are reproduced in Table 1 for convenience.

The average annual load growth over the study period 2005/06 to 2013/14) is 30 MW. In the context of this study, the total system peak load beyond 2013/14 is assumed to grow at 30 MW per year.

TABLE 1
FORECASTED SYSTEM PEAK LOADS

K	Fiscal Year	Total System Peak Load (MW)	Load Growth per Year (MW)*
0	2004/05 (current year)	4028	
1	2005/06	4053	25
2	2006/07	4088	35
3	2007/08	4126	38
4	2008/09	4153	27
5	2009/10	4180	27
6	2010/11	4201	21
7	2011/12	4228	27
8	2012/12	4258	30
9	2013/14	4296	38
Average			29.778
k > 9	Beyond 2013/14		30

*Note: 29.778 MW/Year is the 9-year average load growth rate.

3.5. Annual T&D Capital Expenditures

3.5.1. A Quick Look at T&D Capital Budget

The T&D capital budget is divided into major and domestic items. The major items are typically over $2,000,000 and each of them has a Capital Project Justification (CPJ) and a Capital Expenditure Revision (CER). Domestic items consist of many smaller projects, which are usually grouped into the following areas:

- Transmission Planning & Design (TP&D)
- Distribution Planning & Design (DP&D)
- Construction and Line Maintenance
- Distribution Construction
- System Operations
- Apparatus Maintenance

- VP Transmission & Distribution

Domestic items are further split into blanket and non-blanket categories. Blanket projects are typically smaller than $300,000 and not required to have a CPJ or CER. Non-blanket projects are typically between $300,000 and $2,000,000, and each of them has a CPJ and CER.

Some items in the TP&D and DP&D areas are load-growth related; those in the other five areas, however, are not driven by load growth and therefore are excluded from the marginal cost study.

3.5.2. Analysis of T&D Capital Expenditures

This section is to identify the load-growth related part of the TP&D and DP&D capital expenditures (see Appendix B). A load related capital item may be driven by several factors in addition to load growth. As rules of thumb, the following guidelines are used for splitting a capital item between load-related and non-load-related portions:

- Major item or non-blanket item:
    - 100% load related if it is mainly driven by load growth.
    - 0% load related if it is mainly driven by factors other than load growth.
    - 50% load-related if it is driven by load growth and other factors.
    - Other percentage based on judgment.
- TP&D domestic budget - blanket:
    - Transmission line additions & modifications: 50% load-related.
    - Station site acquisition: 50% load-related.
    - Property land right acquisition: 0% load-related
    - Others: 0% load related.

- DP&D domestic budget – station blanket: 75% load-related.
- DP&D domestic budget – distribution blanket:
  - Subtransmission (S/T) additions & modifications: 50% load-related.
  - S/T system – ice melting: 0% load-related.
  - Street lighting: 0% load-related.
  - Highway changes: 0% load-related.
  - S/T modifications – storm damage: 0% load-related.
  - System improvements: 80% load-related.
  - Customer service: 50% load related.
  - New & upgraded feeders: 50% load-related.
  - Underground residential dist: 50% load-related.
  - Defective cable replacements: 0% load-related.
  - Others: 0% load-related.

Note that the guidelines for splitting the DP&D domestic blanket items are based on the advice from Distribution Planning & Design at Winnipeg, Brandon and Selkirk.

The major items are analyzed on a project-by-project basis and the results are summarized in Appendix B.

Unlike major items, TP&D and DP&D domestic items include many small projects. The annual domestic budgets have been projected for future years within the planning horizon, but are not defined in detail. In such a situation, what we can do is to analyze the 2003/04 domestic budget, and assume that the result (i.e. load-related portion in %) will hold for the future years. The non-blanket items for 2003/04 are analyzed on a project-by-project basis and the blanket budget is analyzed by categories.

According to the "Analysis of Domestic Items" provided in the "Manitoba Hydro Management Report" issued Feb. 2004 (see Appendix A), 76.6% of the T&D domestic budget goes to the TP&D and DP&D categories. So we may reasonably assume that the budget for TP&D and DP&D is 75% of the T&D domestic budget.

Summarized in Appendix B is the analysis of the TP&D and DP&D domestic budgets provided in "2003/04 T&D Domestic Reports" issued by Financing Department, T&D. According to Table B.2 in Appendix B, about 55% of the TP&D and DP&D domestic budget is load related. Thus we assume a 50/50 split between load and non-load related portions. Also according to Table B.2, we assume that the load-related part can be further divided as follows: 5% for transmission, 25% for subtransmission, and 70% for distribution-circuit.

The above results are summarized below:

- Total T&D domestic budget:
  - 75% for TP&D and DP&D categories
  - 25% for other categories (irrelevant to marginal costs)
- Total TP&D and DP&D domestic budget:
  - 50% for capacity-related projects
  - 50% for non-capacity related projects (irrelevant to marginal costs)
- Capacity-related part of TP&D and DP&D domestic budget:
  - 5% for transmission
  - 25% for subtransmission
  - 70% for distribution-circuit

The load-growth related (capacity related) cash flows for the different categories are given in Tables 2 and 3 (referring to Appendix B).

TABLE 2

LOAD-GROWTH RELATED ANNUAL INVESTMENT STREAMS EXPRESSED IN TERMS OF "THEN-CURRENT" DOLLARS* (IN THOUSANDS OF DOLLARS)

K	Fiscal Year	Transmission	Distribution		Transmission & Distribution
			Subtransmission	Distribution-Circuit	
0	2004/05 (current year)	2,050	7,622	21,341	31,014
1	2005/06	4,138	7,791	21,814	33,743
2	2006/07	10,670	9,561	22,339	42,570
3	2007/08	21,811	17,302	22,811	61,925
4	2008/09	33,070	15,932	23,336	72,339
5	2009/10	33,859	28,726	23,835	86,419
6	2010/11	50,040	16,156	24,439	90,635
7	2011/12	50,669	8,775	24,570	84,014
8	2012/12	15,660	8,841	24,754	49,255
9	2013/14	30,697	9,292	25,620	65,609

**Note: The effect of inflation is included and the assumed inflation rate is 2%.*

TABLE 3

LOAD-GROWTH RELATED ANNUAL INVESTMENT STREAMS EXPRESSED IN TERMS OF 2004 CONSTANT DOLLARS* (IN THOUSANDS OF DOLLARS)

K	Fiscal Year	Transmission	Distribution		Transmission & Distribution
			Subtransmission	Distribution-Circuit	
0	2004/05	2,050	7,622	21,341	31,014
1	2005/06	4,057	7,638	21,386	33,081
2	2006/07	10,255	8,856	21,471	40,582
3	2007/08	20,553	14,543	21,496	56,592
4	2008/09	30,551	13,398	21,559	65,509
5	2009/10	30,667	22,870	21,588	75,125
6	2010/11	44,434	13,321	21,701	79,456
7	2011/12	44,110	7,639	21,390	73,139
8	2012/12	13,366	7,545	21,127	42,038
9	2013/14	25,686	7,763	21,438	54,886
Equivalent		23,755	11,586	21,467	56,808
> 9	Beyond 2013/14	23,755	11,586	21,467	56,808

**Note: The values do not include the effect of inflation and the assumed inflation rate is 2%.*

3.6. Interest and Inflation Rates

The values for the inflation rate j, real discount rate i (not including the inflation rate component) and discount rate d (including the inflation rate component) are taken to be 2.0%, 6.0% and 8.15%, respectively, according to the document “Projected Escalation, Interest and Exchange Rates — G911-1” issued 2004 05 27. Note that (1+2.0%)×(1+6.0%) – 1 = 8.15%.

4. Results of Marginal T&D Costs

This section presents the results of marginal T&D costs calculated using the methodology and data in the previously sections. MS Excel and Visual Basic are used to realize the calculations.

4.1. Uniform and Near-Uniform Load Reduction Streams

The calculated marginal costs for uniform and near-uniform load reduction streams are shown in Tables 4 and 5, noting that for a near-uniform load reduction stream, the OYD and ADT methods become identical.

TABLE 4
MARGINAL COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE OYD METHOD

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Uniform Load Reduction Stream	48.86	23.09	42.35
Near-Uniform Load Reduction Stream	45.21	22.05	40.86

TABLE 5
MARGINAL COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE ADT METHOD FOR UNIFORM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Load Reduction Equal to Average Annual Load Growth	48.69	23.04	42.26
Load Reduction Equal to 0.1 Times Average Annual Load Growth	50.13	23.70	43.46

From Tables 4 and 5, the following observations can be made:

- The marginal costs for uniform and near-uniform load reduction streams are very close so that they are interchangeable.
- The marginal costs given by the two methods are very close so that they are interchangeable.
- The marginal costs are practically insensitive to the size of load reduction.

4.2. Random Load Reduction Stream

Consider a random load reduction stream $\{\delta L_k\} = \{\lambda_k \Delta L_k\}$ where λ_k is uniformly distributed between α and 1 with $\alpha = 0$. Results are produced for one million (1,000,000) samples of such a random load reduction stream. Each sample is obtained using the following algorithm:

Randomize
For k =1 to N
$\lambda_k \Leftarrow$ Rnd()
$\delta L_k \Leftarrow \lambda_k \Delta L_k$
Next k

The function Rnd() is a random-number generator in MS Visual Basic which returns a random number between 0 and 1. The Randomize statement is used to initialize the random-number generator so that each random-number sequence does not repeat the previous ones. The load reduction streams thus obtained are different from each other. An instance of them might look like {0.0277×25, 0.3086×35, 0.4042×38, 0.2399×27, 0.5535×27, 0.5878×21, 0.2465×27, 0.9231×30, 0.1233×38}.

The cumulative frequency distributions (CFD) of the marginal costs calculated using the OYD method are plotted in Figs. 2 to 4. The CFD, $F(x)$, is defined as the ratio of the number of data values smaller than x to the total number of data entries (i.e. 1,000,000).

Figures 2 to 4 indicate that the marginal costs are governed by the normal distribution. Thus, the probability that the marginal cost falls within 1, 2 and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively. The same is also true for the marginal costs obtained using the ADT method.

The averages (mean) and standard deviations of the marginal costs calculated using the two methods are shown in Tables 6 and 7. The values provided in the two tables are almost identical. Thus, we may conclude that the OYD and ADT methods are equivalent or interchangeable.

In addition, upon comparing Table 6 or 7 with Table 4 it is found that the average (mean) of the marginal cost is very close to the marginal cost for a uniform or near-uniform load reduction stream.

Based on the above discussions, we recommend using the values provided in Table 6 as the generic marginal costs. The range of 1, 2 or 3 standard deviations from the average may be chosen for sensitivity study.

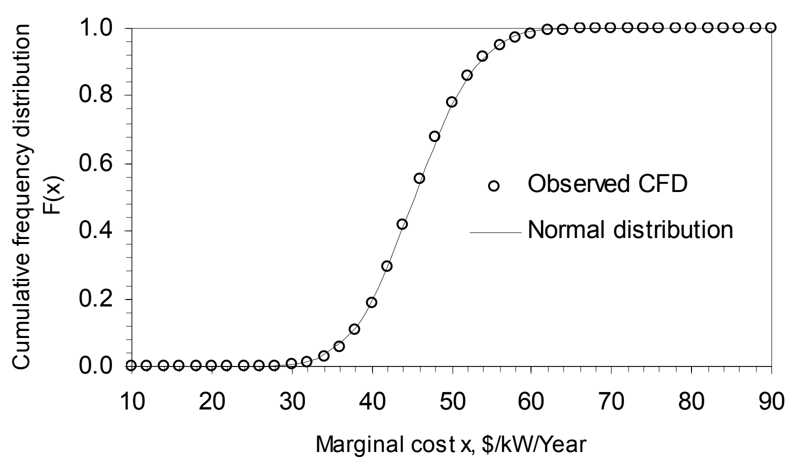


Fig. 2. The cumulative frequency distribution (CFD) of transmission marginal costs. The mean = 45.44 $/kW/Year; the standard deviation = 6.19 $/kW/Year.

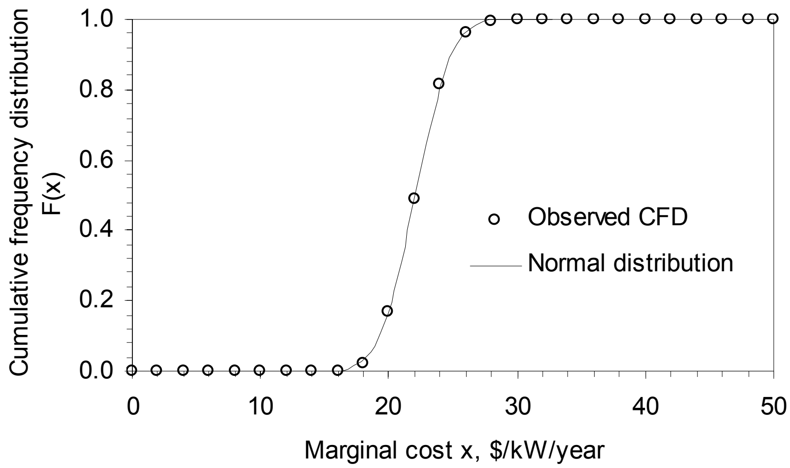


Fig. 3. The cumulative frequency distribution (CFD) of subtransmission marginal costs. The mean = 22.09 $/kW/Year; the standard deviation = 2.12 $/kW/Year.

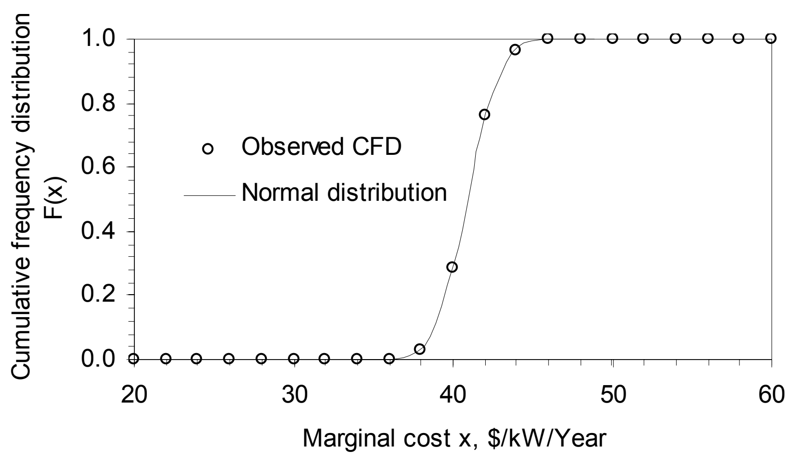


Fig. 4. The cumulative frequency distribution (CFD) of distribution marginal costs. The mean = 40.93 $/kW/Year; the standard deviation = 1.60 $/kW/Year.

TABLE 6
MARGINAL T&D COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE OYD METHOD FOR A RANDOM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average	45.44	22.09	40.93
Standard Deviation	6.19	2.12	1.60

TABLE 7
MARGINAL T&D COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE ADT METHOD FOR A RANDOM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average	45.90	22.31	41.35
Standard Deviation	6.21	2.13	1.62

4.3. Comparison with Existing Avoided Costs

The transmission and distribution avoided costs (in 1990 dollars) recommended in the 1990 avoided cost study [4,5] are $11/kW/Year and $11/kW/Year, respectively (see Appendix C). They escalate to $15/kW/Year and $15/kW/Year (in 2004 dollars), respectively, assuming an escalation rate of 2%. These values are much lower than those provided in the present study, which is attributed to the following factors:

- The increment transmission and distribution investments per kW of load growth were $130/kW/Year and $286/kW/Year (1990 dollars), respectively, as estimated in Appendix C, which are much lower than those in the present study. The lower values are due to lower capital investments and higher load growth (see Appendix C).

- Because of the “significance level” requirement, the load reductions associated with the 100 MW DSM program were not considered to cause capital deferrals until after 1998/99. That is, the capital costs for the first 7 years (between 1990/91 to 1998/99) were treated as “sunk” costs in the avoided cost estimates. The avoided costs derived from the capital expenditures in the distant future (from 1998/99 to 1014/15) were heavily discounted. For example, $1 in 1997 was discounted to $0.665 in 1990 assuming a real discount rate of 6%.

- The residual values of the capital investments at the end of the study period were treated as actual cash flows and accounted for in the

1990 avoided cost estimates. This lowers the transmission and distribution deferral values (i.e. savings from capital deferrals) by 29% and 57%, respectively (see Appendix C).

5. Related Subjects

5.1. Predicting Marginal Costs beyond Planning Horizon

The marginal (or avoided) cost C_{avoid} is calculated over the planning horizon that is 10 years in the current T&D planning practice. There is no approved investment plan available for us to calculate the marginal cost beyond the planning horizon. On the other hand, the marginal cost is often used for evaluating alternatives spanning across a period much longer than 10 years. Therefore we need to project the marginal cost beyond the planning horizon. One way of doing it is simply to assume that the levelized marginal cost in constant-worth dollars will continue into the future beyond the planning horizon. Another way is to assume that the 10 year T&D constant-worth dollar investment stream will repeat itself every 10 years and apply the methods previously presented to estimate the marginal cost for a longer period.

5.2. Effect of Discount Rate

The marginal costs in the previous sections are obtained for a real discount rate of 6% (without the inflation rate component). For a different real discount rate, we will have different marginal costs. Because the marginal costs reflect the savings from capital cost deferrals, a larger discount rate will lead to larger marginal cost values. The marginal costs calculated for a number of different real discount rates are plotted in Fig. 5 where the factor f_d is the ratio of the marginal cost for a discount rate of 6% to that for a discount rate of i. An approximate mathematical expression for the relationship is found through curving fitting as follows:

$$f_d = -67.8i^2 + 19.7i + 0.057 \tag{21}$$

The f_d v.s. i curve can be used to modify the marginal cost values provided in this report if the projected real discount rate is significantly different from 6.0%. For example, the results in Tables 6 and 7 can be multiplied by a factor of 1.2 to obtain those for a real discount rate of 8.0%. It is noted that the factor f_d is not only applicable to the average, but also to the standard deviation.

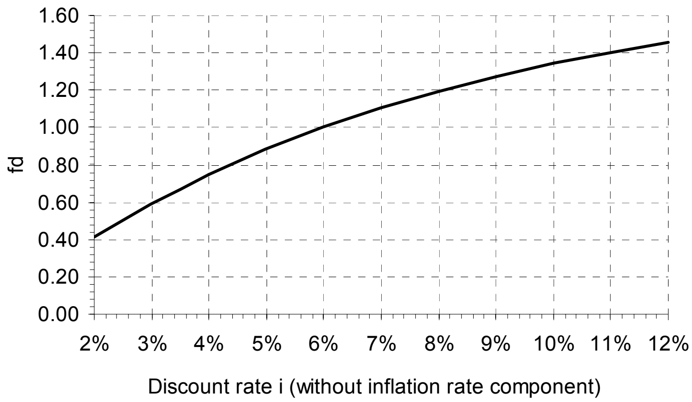


Fig. 5. Marginal cost v.s. real discount rate.

5.3. Marginal Cost with Respect to Larger Load Reduction

In the previous sections, we focus on the marginal cost associated with small load reductions, i.e. from 0 to the amount of one-year load growth. It has been shown that a variation in the size of load reduction within this range would cause a negligible change in the marginal cost for uniform and near-uniform load reduction streams. Now we would like to examine the situation with respect to larger load reductions, say, close to two times the average annual load growth.

As discussed in Section 2.4, a uniform load reduction stream equal to the average annual load growth ΔL_{ave} over the study period can be assumed to cause the entire load growth related investment plan to shift by one year and the resultant error is negligible. This assumption can actually be extended to the situation where load reductions are equal to $m\Delta L_{ave}$ ($m = 2, 3$) by changing the deferral time from one year to m years. Thus, the marginal cost can be approximately determined as

$$C_{avoid\_m} = \frac{1}{m}[1 - \frac{1}{(1+i)^m}][\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ [\Delta L_{ave} \sum_{k=1}^{N} \frac{1}{(1+i)^k}] \tag{22}$$

From this equation, we have

$$C_{avoid\_m} \big/ C_{avoid\_1} = \frac{1}{m}[1 - \frac{1}{(1+i)^m}]/(1 - \frac{1}{1+i}) \tag{23}$$

For $m = 2$,

$$C_{avoid\_2} \big/ C_{avoid\_1} = \frac{1}{2}[1 - \frac{1}{(1+i)^2}]/(1 - \frac{1}{1+i}) \approx 1 - i/2 \tag{24}$$

This indicates that as the size of load reduction is increased from one to two year load growth, the marginal cost varies by about $0.5i \times 100\%$, which is 3% for $i = 6.0\%$ for example. Therefore, the marginal costs given by the OYD method and the ADT method can be applied in the situation where the size of load reduction is between zero and two times the average annual load growth.

6. Concluding Summary

A rigorous method for estimating marginal T&D costs has been developed in this report on the basis of the deferral value of future load-growth related capital expenditures due to a reduction in the forecasted system peak load (demand). It is named the one-year deferral (OYD) method. Another deferral value based method has been presented as well, which is essentially the Present Worth method proposed in [2,8,10] and renamed the arbitrary deferral time (ADT) method in this report. The OYD and ADT methods differ mainly in the restrictions imposed on the deferral time. In the OYD method, the deferral time is restricted to one year, and only part of the load-growth related annual investments are deferred; in the other one, all the load-growth related annual investments are deferred by a period Δt_k that is defined as $\Delta t_k = \delta L_k / \Delta L_k$ and not restricted to integer values in years.

The marginal cost estimates in this report are based on the “T&D Capital Expenditure Forecast (CEF03-1)” for the years 2003/04 – 2013/14 and the Corporate “Electric Load Forecast” for the years 2003/04 to 2013/14. The marginal costs are split into transmission, subtransmission, and distribution-circuit components. The inflation rate, j, and the real discount rate, i (without the inflation rate component), are taken to be 2.0% and 6.0%, respectively, according to the document “Projected Escalation, Interest and Exchange Rates — G911-1”, issued 2004 05 27.

Numerical tests on the two methods are conducted for three types of load reduction streams: uniform, near-uniform and random. The followings observations have been made:

- The marginal costs for uniform and near-uniform load reduction streams are very close so that they are interchangeable.
- The marginal cost for a random load reduction stream is governed by the normal distribution. The probability that the marginal cost is within 1, 2 and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively.
- The OYD and ADT methods give practically the same marginal costs.
- The average (mean) of the marginal cost for a random load reduction stream is practically equal to that for a uniform or near-uniform load reduction stream.

Several related issues have been discussed, which includes the marginal costs beyond the 10 planning horizon, the effect of the discount rate on the marginal cost, etc.

The marginal costs presented in the report are non-area specific and winter-peak-load related. The values in Table 6 are recommended as the generic marginal T&D costs. The range of 1, 2 or 3 standard deviations from the average may be chosen for sensitivity study.

It should be borne in mind that the marginal costs provided in this report may not be applicable in the situations where there is a very large load change (say, much larger than two times the annual load growth), or where the capacity expansion is based on the summer system peak load (demand).

Recommended future work is summarized below (but not limited to):

- To develop more sophisticated guidelines for extracting the load-growth related capital costs from the T&D Capital Expenditure Forecast;
- To update the marginal T&D costs every 5 years or on an as-needed basis;
- To develop an area-specific marginal T&D costing method if needed;
- To develop marginal costs for summer peaking distribution systems if needed.

7. References

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[11] "Capital Expenditure Forecast (CEF03-1), 2003/04 – 2013/14", Volume 2 of 2, Transmission & Distribution, Manitoba Hydro, November, 2003.

[12] "Electrical Load Forecast, 2003/04 to 2023/24", Market Forecast, Manitoba Hydro, May, 2003.

Appendix A

- **Manitoba Hydro Net Electric Load Forecast, 2003/04 to 2023/2024**
- **Projected Escalation, Interest and Exchange Rates – G911-1, Issued 2004 05 27**
- **Analysis of Domestic Items, Manitoba Hydro Management Report, Feb. 2004**

Table 1

MANITOBA HYDRO NET ELECTRIC LOAD FORECAST
2002/03 - 2023/24

Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
2002/03 Actual	21940	7.1%	3916	4.1%	64.0%
Weather	-272		14		
2002/03 Adjusted	21668 -	4.5%	3930	4.3%	62.9%
2003/04	22171	2.3%	3956	0.7%	64.0%
2004/05	22690	2.3%	4028	1.8%	64.3%
2005/06	22976	1.3%	4053	0.6%	64.7%
2006/07	23262	1.2%	4088	0.9%	65.0%
2007/08	23554	1.3%	4126	0.9%	65.2%
2008/09	23783	1.0%	4153	0.7%	65.4%
2009/10	24009	1.0%	4180	0.7%	65.6%
2010/11	24203	0.8%	4201	0.5%	65.8%
2011/12	24430	0.9%	4228	0.6%	66.0%
2012/13	24680	1.0%	4258	0.7%	66.2%
10 Year Avg.		1.3%		0.8%	
2013/14	24927	1.0%	4296	0.9%	66.2%
2014/15	25191	1.1%	4338	1.0%	66.3%
2015/16	25458	1.1%	4380	1.0%	66.4%
2016/17	25729	1.1%	4422	1.0%	66.4%
2017/18	26001	1.1%	4465	1.0%	66.5%
2018/19	26274	1.1%	4508	1.0%	66.5%
2019/20	26576	1.1%	4556	1.1%	66.6%
2020/21	26847	1.0%	4599	0.9%	66.6%
2021/22	27143	1.1%	4646	1.0%	66.7%
2022/23	27436	1.1%	4692	1.0%	66.8%
2023/24	27675	0.9%	4730	0.8%	66.8%
21 Year Avg.		1.2%		0.9%	

\- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

PROJECTED ESCALATION, INTEREST AND EXCHANGE RATES—G911-1

ITEM (Fiscal Year)		HISTORICAL**						PROJECTED***					
		1998/ 99	1999/ 00	2000/ 01	2001/ 02	2002/ 03	2003/ 04	2004/ 05	2005/ 06	2006/ 07	2007/ 08	2008/ 09	2009/ 10 & on
* 1. Hydro-electric Generation Plant						Preliminary							
	Weight												
Structures	0.502	1.2	1.6	3.7	2.8	2.0	2.1						
Equipment	0.216	0.8	1.1	2.3	2.2	2.4	1.7						
Camps & Site Roads	0.167	0.8	0.8	2.3	1.7	0.9	-1.4						
Eng.& Admin.	0.115	8.5	3.6	0.1	1.5	0.4	0.4						
	1.000												
Hydro Projects: Composite Escalation Rate		1.9	1.6	2.7	2.3	1.7	1.1	2.0	2.0	2.0	2.0	2.0	2.0
*2.General Constr.(Composite)		2.3	2.4	3.6	3.4	1.9	2.1	2.0	2.0	2.0	2.0	2.0	2.0
Labour		2.9	2.8	5.2	2.3	2.9	2.3						
Materials		2.0	2.1	2.0	4.4	1.0	1.9						
3.MH short term Cdn debt rate		5.74	5.74	6.40	4.22	3.91	3.61	3.65	4.35	4.95	5.25	5.50	5.70
MH long term Cdn debt rate		6.35	7.00	7.03	6.90	6.74	6.32	6.50	6.95	7.15	7.15	7.20	7.40
MH long term U.S. debt rate		6.71	7.67	7.66	7.22	6.09	5.80	6.35	6.95	7.15	7.20	7.45	7.65
4.Weighted Average Cost of Capital (%)								← 8.15 →					
*5.Consumer Price Index													
MbCPI		1.45	2.30	2.50	2.10	2.31	0.97	2.0	2.0	2.0	2.0	2.0	2.0
CdnCPI		0.94	2.20	2.76	2.22	2.98	1.87	2.0	2.0	2.0	2.0	2.0	2.0
6.Real Weighted Avg. Cost of Capital (8.15 - 2.0)/1.02 (%)								← 6.00 →					
7.Real Hurdle Rates for Project Evaluation (minimum % rates of return)								← 6.00 to 15+ → See item 7 below and Hurdle Rates (G911-4)					
* 8.U.S Price Deflator		1.16	1.63	2.21	2.29	1.50	1.71	1.55	1.80	2.05	2.25	2.25	2.25
9.U.S.—Cdn. Exchange Rate (Cdn. $ per U.S. $)		98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
		1.504	1.471	1.504	1.565	1.549	1.353	1.31	1.33	1.37	1.36	1.35	1.35
		10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/10	20/21	21/22
		1.35	1.35	1.34	1.34	1.34	1.34	1.33	1.33	1.33	1.32	1.32	1.32
		22/23	23/24	24/25									
		1.31	1.31	1.31									

*	Represents current fiscal year over previous fiscal year, % change
**	Historical:
Item 1	Statistics Canada – ELECTRIC UTILITY CONSTRUCTION PRICE INDEX SERIES As Statistics Canada preliminary estimates for 2004 are NOT available, the 2003 values are being used as preliminary estimates.
Item 2	Canadata - SOUTHAM CONSTRUCTION COST INDEX
Item 3	Manitoba Hydro—Treasury (includes Provincial Guarantee Fee of 0.5% for 1998/99). Actuals may also reflect short term and foreign borrowing costs. NOTE: 1999/00 includes a guarantee fee of 0.65% while 2000/01 includes a guarantee fee of 0.70%. NOTE: 2001/02 and beyond includes a guarantee fee of 0.95%.
Item 4	Cost of Capital = 0.75 * Cost of Debt + 0.25 * Imputed Cost of Equity = 0.75(7.40) + 0.25(7.40 + 3) = 8.15 where a 3% premium is added to the cost of debt to impute value for equity
Item 5	Manitoba Bureau of Statistics—MANITOBA STATISTICAL REVIEW, Table 29 & 30 and Stats Bulletin
Item 6	(Nominal Cost of Capital - MbCPI)/(1+[MbCPI/100]) – This is rounded to 6%.
Item 7	For project evaluation real hurdle rates ranging from 6.00% to 15%+ are to be applied. The hurdle rates used will reflect the degrees of risk deemed to be inherent in the associated cash flows. [See Application and Derivation of Hurdle Rates (G911-41) for further information]
Item 8	U.S. Bureau of Economic Analysis – National Accounts Data – Table 5
Item 9	Bank of Canada Weekly Financial Statistics – For economic evaluations only
***	Projected as per Economic Outlook 2004 – Spring 2004 (EO04-1)

☐ = Preliminary

EFFECTIVE 2004 05 18
ISSUED 2004 05 27

Executive Committee Minute #1028.03

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Note: This page is part of the Manitoba Hydro Management Report, Feb. 2004.

ANALYSIS OF DOMESTIC ITEMS
(IN THOUSANDS OF DOLLARS)
FOR THE ELEVEN MONTH PERIOD ENDED FEBRUARY 29, 2004

	BLANKETS			NON-BLANKETS					
	FORECAST	RELEASES	ACTUAL	FORECAST	RELEASES	ACTUAL	FORECAST	RELEASES	ACTUAL
CORPORATE	4 922 *						4 922 *		
PUBLIC AFFAIRS	--	--	--	--	--	--	--	--	--
GAS SUPPLY & SERVICES	--	--	--	--	--	--	--	--	--
HUMAN RESOURCE	301	--	160	--	--	--	301	--	160
RATES & REGULATORY AFFAIRS	--	--	--	500	500	225	500	500	225
INFORMATION TECHNOLOGY	8 946	8 800	6 170	4 626	4 626	7 264	13 572	13 426	13 434
CORPORATE PLANNING	--	--	--	--	--	--	--	--	--
CORPORATE CONTROLLER	--	--	--	--	--	--	--	--	--
PRESIDENT & CEO	--	--	--	5	5	11	5	5	11
	14 169	8 800	6 330	5 131	5 131	7 500	19 300	13 931	13 830
POWER SUPPLY	919 *						919 *		
POWER PLANNING	70	--	15	603	603	56	672	603	71
HVDC	565	209	280	2 590	2 591	2 209	3 155	2 800	2 489
GENERATION NORTH	769	--	887	2 258	2 257	1 432	3 026	2 257	2 318
GENERATION SOUTH	1 856	710	1 407	5 974	5 974	7 292	7 830	6 684	8 698
ENGINEERING SERVICES	250	--	19	1 248	1 247	546	1 498	1 247	565
POWER SUPPLY ADMINISTRATION	100	--	1	--	--	--	100	--	1
	4 528	919	2 609	12 672	12 673	11 534	17 200	13 592	14 142
TRANSMISSION & DISTRIBUTION	1 533 *						1 533 *		
TRANSMISSION PLANNING & DESIGN	2 313	910	1 693	9 495	9 494	6 896	11 808	10 403	8 589
DISTRIBUTION PLANNING & DESIGN	26 990	24 343	30 597	14 942	14 973	13 626	41 932	39 316	44 223
CONSTRUCTION & LINE MAINTENANCE	2 000	--	1 632	6	6	2	2 006	6	1 634
DISTRIBUTION CONSTRUCTION	325	--	190	365	365	324	690	365	514
SYSTEM OPERATIONS	3 636	--	1 923	2 572	2 571	2 912	6 208	2 571	4 835
APPARATUS MAINTENANCE	5 090	3 844	4 436	774	887	610	5 864	4 731	5 046
VP TRANSMISSION & DISTRIBUTION	942	482	461	672	(345)	467	1 614	137	928
	42 829	29 579	40 933	28 826	27 950	24 838	71 655	57 530	65 769
CUSTOMER SERVICE & MARKETING	(148) *						(148) *		
CUSTOMER SERVICE OPERATIONS	52 596	47 576	47 402	--	--	507	52 596	47 576	47 909
SUPPORT SERVICES	2 273	--	2 442	--	--	--	2 273	--	2 442
CUSTOMER SERVICE & MARKETING ADMINISTRATION	--	--	--	18	18	55	18	18	55
	54 721	47 576	49 844	18	18	562	54 739	47 595	50 406
TOTAL	116 248	86 873	99 716	46 647	45 773	44 435	162 894	132 647	144 147

* BALANCE OF ALLOCATED FORECAST

04 03 16

Appendix B

- **Summary of T&D Capital Expenditure Forecast (CEF03-1)**
- **Analysis of TP&D and DP&D Major and Domestic Items**
- **Load-Growth Related T&D Annual Investment Streams**

CAPITAL EXPENDITURE FORECAST (CEF03-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2003/04 TO 2013/14

	PROJECT TOTAL	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TRANSMISSION & DISTRIBUTION												
GLENBORO-RUGBY 230KV T/L	30.5	0.9	0.4									
HERBLET LAKE - THE PAS 230kV TRANSMISSION	57.3			1.1	4.8	15.4	18.4	16.6	0.9			
WINNIPEG to BRANDON TRANSMISSION SYSTEM IMPROVEMENTS	34.9						1.9	1.1	3.1	3.0	4.7	21.1
RIDGEWAY 230-66KV TRANSFORMER ADDITION	9.3			0.2	0.5	0.7	4.4	3.5				
DORSEY-ROSSER 230KV TRANSMISSION IMPROVEMENT	2.5	0.1	0.4									
DORSEY - LaVERENDRYE - ST. VITAL 230kV TRANSMISSION	28.1										5.6	7.7
ROSSER - SILVER 230KV TRANSMISSION	30.4	2.4	7.6	13.9								
NEEPAWA 230-66KV STATION	20.9	0.0	0.0	0.0	0.0	0.0	0.2	1.1	9.2	10.3		
ROSSER - MCPHILLIPS 115KV TRANSMISSION IMPROVEMENTS	2.8	2.5	0.2									
RICHER SOUTH 230-66KV TRANSFORMER ADDITION	5.3	0.0	0.5	0.6	2.3	1.8						
PINE FALLS - BLOODVEIN 115kV TRANSMISSION	32.3				0.2	0.3	1.1	2.9	7.1	17.1	3.6	
ST. VITAL - STIEBACH 230kV TRANSMISSION	24.7			0.6	0.6	1.0	3.8	4.9	13.8			
RIDGEWAY - SELKIRK 230KV TRANSMISSION	27.1		1.0	2.6	4.0	4.4	5.0	10.0				
SOURIS - PEMBINA VALLEY 230kV TRANSMISSION	34.0	0.0	0.0	0.0	0.7	0.9	1.6	1.9	12.2	16.8		
WINNIPEG AREA TRANSMISSION REFURBISHMENT	8.4	0.5	0.9									
DORSEY - US D602F 500KV AC T/L INSULATOR REPL	7.4	0.2	0.0									
DORSEY 230KV BUS ENHANCEMENTS	17.5	4.8	2.0									
FLIN FLON AREA TRANSMISSION IMPROVEMENTS PHASE 2	13.1	1.9	7.9	1.5	0.0							
PINE FALLS - GREAT FALLS 115-66KV SUPPLY	10.3	5.7	0.0	0.0	0.0	0.0	0.0	0.2	1.9	1.7	0.0	
RUTTAN - SOUTH INDIAN LAKE 66KV LINE	13.7	2.8	1.1									
CENTRAL SUPPLY PIKWITONEI & THICKET PORTAGE	5.4	0.3										
BIRTLE SOUTH - ROSSBURN 66KV LINE	4.9											0.1
ST. BONIFACE PLESSIS RD 115-25KV STATION	18.3	0.3	0.5									
ST. BONIFACE PLESSIS RD BK2 ADDITION	2.1	0.4	0.2									
ROSSER OAK POINT 115-24kV STATION	22.1	0.0	0.0	0.0	0.0	1.6	2.3	13.5	4.6			
ROSSER OAK POINT BANK 2 ADDITION	10.3						1.0	6.4	2.8			
BRANDON CROCUS PLAINS 115-24KV BANK ADDITION	8.6	0.0	0.0	0.0	0.8	4.6	2.9	0.3				
FT GARRY PERIMETER SOUTH BANK REPL	5.1				0.7	3.0	1.4					
ROVER SUB STATION REPLACE 4KV SWITCHGEAR	5.6	0.2	4.2	1.3								
PORTAGE SOUTH 230-66kV 2nd TRANSFORMER ADDITION	7.9	0.2	5.4	2.2								
VIRDEN AREA DISTRIBUTION CHANGES	17.2	0.8	1.0	1.7								
DEFECTIVE RINJ CABLE REPLACEMENT	8.6	1.0	1.4	1.4	1.5							
BRERETON LAKE STATION AREA	8.6	5.3	0.7	0.8	0.6	0.1						
SHAMATTAWA NEW DIESEL GS & TANK FARM	16.4	1.8	0.4	1.7	0.7							
HARROW STATION BANK 3 INSTALLATION	2.6	0.0	1.9	0.7								
STONY MOUNTAIN NEW 115-12KV STATION	3.3	0.0	0.5	1.3	0.3	1.2						
COMMUNICATIONS	158.2	39.8	16.2	23.9	22.8	10.2	1.0					
MAPINFO IMPLEMENTATION	30.5	1.0										
INTEGRATION OF SYSTEM CONTROL CENTRES	3.8	0.7	1.9	1.2								
SITE REMEDIATION	10.9	0.7	3.1	1.0	0.1							
OIL CONTAINMENT	7.5	0.6	1.1	1.1	1.2	1.1	1.4					
DOMESTIC ITEM		71.7	81.3	83.1	85.1	86.9	88.9	90.8	93.1	93.6	94.3	97.6
TRANSMISSION & DISTRIBUTION TOTAL		146.7	141.5	142.2	127.1	133.3	135.4	153.2	148.9	142.5	108.1	126.6

Table B.1. Analysis of T&D Major Items for Years 2003/04 To 2013/14 (Including Effect of Inflation)

Items	Justification	Comments	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Transmission -- major items:		100% load related											
Herblet Lake - The Pas 230 kV Transmission	Load and reliability	To provide firm supply for increasing Flin-Flon and The-Pas loads			1,147	4,785	15,398	18,378	16,607	945			
Winnipeg to Brandon Transmission System Improvement	Load and reliability	To accommodate West MB area future load growth						1,889	1,065	3,110	2,974	4,726	21,119
Ridgeway 230-66 kV Transformer Addition	Load and reliability	To supply increased Wpg load			244	453	727	4,410	3,487				
Dorsey - LaVerendrye - St. Vital 230 kV Transmission	Load and reliability	To provide firm supply for East MB loads										5,576	7,748
Neepawa 230-66 kV Station	Load and reliability	To supply Neepawa and related Western region future load growth						195	1,126	9,219	10,326		
Richer South 230-66 kV Transformer Addition	Load and reliability	To provide firm supply to Richer area loads	1	516	602	2,294	1,836						
Pine Falls - Bloodvein 115 kV Transmission	Load and reliability	To accommodate Lake Wpg East area load increases				241	266	1,135	2,880	7,134	17,103	3,554	
St. Vital - Steinbach 230 kV Transmission	Load and reliability	To accommodate load growth in South-eastern MB			576	632	1,017	3,819	4,883	13,769			
Souris - Pembina Valley 230 kV Transmission	Load and reliability	To support load growth in South-western MB	1	1	1	658	926	1,564	1,858	12,217	16,801		
Pine Falls - Great Falls 115-66 kV Supply	Load and reliability	To provide contingency capacity for Paine Falls 66 kV system that will run short due to load growth	5,713	9	10	11	12	13	250	1,900	1,710	36	
Subtotal			**5,715**	**526**	**2,580**	**9,074**	**20,182**	**31,403**	**32,156**	**48,294**	**48,914**	**13,892**	**28,867**
Subtransmission -- major items:		100% load related											
Birtle South - Rossburn 66 kV Line	Load and reliability	To support Rossburn and Shoal Lake area load growth											142
Rosser Oak Point 115-24 kV Station	Load and reliability	To support load growth in the area				37	1,592	2,310	13,494	4,631			
Rosser Oak Point Bank #2 Addition	Load and reliability	To support load growth in the area						1,019	6,449	2,797			
Brandon Crocus Plains 115-24 kV Bank Addition	Load, reliability, etc.	To support load growth in the area		-1	-1	830	4,600	2,875	270				
Ft. Garry Perimeter South Bank Replacement (66-12 kV)	Load	To supply load growth in South Brandon area				716	2,963	1,394					
Subtotal			**0**	**-1**	**-1**	**1,583**	**9,155**	**7,598**	**20,213**	**7,428**	**0**	**0**	**142**
Other major items:		0% load related or 0% of costs can be deferred due to a load reduction											
Dorsey - Rosser 230 kV Transmission Improvements	Load and reliability	To refurbish 230 kV line DR5. Costs should be considered as partially load-related. $1.953 millions has been spent.	132	368									
Rosser - McPhillips 115 kV Transmission Improvements	Load and reliability	To increase transmission capacity for load support. ISD is the current year and costs can not be deferred.	2,536	174									

Ridgeway - Selkirk 230 kV Transmission	Load and reliability	To provide supply to Selkirk area to alleviate flicker problems and to support Parkdale area. The flicker problems will be resolved by installing an SVC and this item will be deferred beyond the 10 planning horizon		965	2,648	3,959	4,433	5,046	10,038				
Winnipeg Area Transmission Refurbishment	Load and reliability	To refurbish the lines to insure safe operating ground clearances. $6.139 millions have been spent.	536	935									
Flin Flon Area Transmission Improvements (Phase 2)	Load, safety, reliability and efficiency	Mainly due to factors other than load growth.	1,873	7,915	1,539	37							
Rosser - Silver 230 kV Transmission	Load and reliability	To provide firm supply to Silver Station to accommodate load growth in Interlake area. Project has already started.	2,417	7,581	13,880								
Ruttan - South Indian Lake 66 kV Line	Load	To support increased South Indian Lake load. ISD is the current year and can not be deferred	2,765	1,076									
St. Boniface Plessis Road 115-25 kV Station	Load and reliability	ISD is the current year and can not be deferred	289	465									
St. Boniface Plessis Road Bank #2 Addition	Load and reliability	ISD is the current year and can not be deferred	363	200									
Portage South 230-66 kV 2nd Transformer Addition	Load and reliability	Costs have been committed	206	5,382	2,222								
Virden Area Distribution Changes	Load, safety, etc.	The project was mainly driven by factors other than load growth	762	993	1,744								
Horrow Station Bank #3 Installation (115-24 kV)	Load and reliability	To provide addition 24 capacity for high load growth. ISD is one year away and can not be deferred		1,906	716								
Stony Mountain New 115-12 kV Station	Load, reliability and efficiency	Existing station equipment and their supply line are in a deteriorated condition and must be replaced. Cost can not be deferred		470	1,342	298	1,232						
Glenboro - Rugby 230 kV T/L	Reliability and other		877	383									
Dorsey - US D602F 500 kV AC T/L Insulator Replacement	Reliability	Replace defective ones	234	24									
Dorsey 230 kV Bus Enhancements	Safety, reliability and efficiency		4,786	1,963									
Central Supply Pikwitonei & Thicket Portage	Salvage diesel units and remediate sites		292										
Rover Substation Replace 4 kV Switchgear	Safety and reliability		159	4,154	1,320								
Defective Rinj (Red Jacket) Cable Replacement	Reliability and service		1,021	1,395	1,445	1,542							
Brereton Lake Station Area	Safety, reliability service and efficiency		5,330	696	751	607	101						
Shamattawa New Diesel GS & Tank Farm	Load and service	Generation related	1,843	358	1,675	673							
Communications	Reliability and service		39,828	16,249	23,908	22,829	10,178	1,038					
MapInfo Implementation	Efficiency		1,041										
Integration of System Control Centers	Reliability and service		721	1,861	1,222								

Site Remediation	Safety and other		656	3,055	1,009	144							
Oil Containment	Safety and other		644	1,075	1,122	1,244	1,138	1,385					
Subtotal			**69,311**	**59,643**	**56,543**	**31,333**	**17,082**	**7,469**	**10,038**	**0**	**0**	**0**	**0**
Domestic items	Part of the costs is load related and to be identified		**71,700**	**81,300**	**83,100**	**85,100**	**86,900**	**88,900**	**90,800**	**93,100**	**93,600**	**94,300**	**97,600**
Total			***146,726***	***141,468***	***142,222***	***127,090***	***133,319***	***135,370***	***153,207***	***148,822***	***142,514***	***108,192***	***126,609***

Table B.2. Split of 2003/04 TP&D and DP&D Domestic Budget (Including Effect of Inflation) Based on Tables B.3 to B.6

		Approved Domestic Budget (in $1,000)			Capacity-Related Portion (in $1,000)		
		Blanket	Non-blanket	Blanket & Non-blanket	Blanket	Non-blanket	Blanket & Non-blanket
				(A) + (B)			(D) + (E)
		(A)	(B)	(C)	(D)	(E)	(F)
(R1)	Transmission	1,132	6,825	7,957	0	1,784	1,784
(R2)	Subtransmission - TP&D	1,132	2,319	3,451	0	2,213	2,213
(R3)	Subtransmission - DP&D	2,761	3,898	6,659	2,071	1,846	3,917
(R4)	Subtransmission (R2+R3)	3,893	6,217	10,110	2,071	4,059	6,130
(R5)	Distribution-circuit	22,087	8,805	30,892	15,150	4,045	19,195
(R6)	Total approved T&D domestic budget (R1+R4+R5)			48,959			
(R7)	Total capacity-related T&D domestic budget (R1+R4+R5)						27,109
(R8)	Capacity-related portion (R7/R6)						55.4%
Split of capacity-related domestic budget:							
	Transmission (R1/R7)						6.6%
	Subtransmission (R4/R7)						22.6%
	Distribution-circuit (R4/R7)						70.8%

Notes:

1). The balances of targets are not included in the analysis

2). The following assumptions may be made according to the above results:

a). The domestic budget may be split between capacity and non-capacity related portions at a ratio of 50/50

b). Capacity-related domestic budget may be split as follows:

5% for transmission,
25% for subtransmission,
70% distribution-circuit.

3). Effect of inflation is included

Table B.3. Analysis of 2003/04 TP&D Domestic Budget -- Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Comments
			in $1,000	
Transmission Lines - Additions & Modifications	125	50%	63	50% load-related (Note: This is an arbitrary assumption)
Station Site Acquisition	85	50%	43	50% load-related based on the assumption that it is for expanding station (or station capacity)
Station Supervisory Control & Automation Modifications	50	0%	0	
Protection & Metering	301	0%	0	
Surveys & Mapping Equipment	123	0%	0	
Property Survey Equipment	20	0%	0	
Property Land Rights Acquisition	650	0%	0	Not used for the purchase of additional land to expand capacity (according to comments from Doreen Devloo, Property Dept.)
TP&D Preliminary Engineering - Stations	784	0%	0	
TP&D Preliminary Engineering - Transmission Lines	125	0%	0	
Total TP&D Blankets -- Transmission	**1,132**		**53**	50/50 split between transmission and subtransmission
Total TP&D Blankets -- Subtransmission	**1,132**		**53**	
Total TP&D Blankets	**2,263**		**105**	TP&D blanket budget is about 7% capacity-related

Notes:

1). The total TP&D blanket of $105,000 is tiny compared to the total of TP&D major items, and therefore will be ignored.

Table B.4. Analysis of 2003/04 TP&D Domestic Budget -- Non-Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Justifications or Comments
			in $,1000	
Transmission				
Dorsey-Neepawa-Cornwallis 230kV T/L	220	100%	220	To provide initial ac system improvements required to transmit power to Brandon area to supply future load growth.
Dorsey-Riel (South Loop) Property Requirements	296	100%	296	Right-of-way for all future contemplated EHV lines in the Winnipeg area
Dorsey West Property Requirements	66	100%	66	Right-of-way for all future contemplated EHV lines in the Winnipeg area.
Dorsey - St. Vital 230kV T/L	42	100%	42	To provide for part of system changes to transmit power from Dorsey to east half of Winnipeg.
William River Stn - G8P Line Switches	-272	0%	0	To provide supply flexibility to Norway House and minimize extended customers outages.
St. Vital 230-115 kV Transformer Addition	178	100%	178	Install a 230-115 kV transformer to meet increased Winnipeg area load
St. Vital 230-115 kV Transformer Addition	4	100%	4	To accommodate Winnipeg area load growth, etc.
500kV Line D602F 'A' Protection Replacement	156	0%	0	Because it is obsolete and requires extensive annual maintenance.
500kV Line 602F 'B' Protection Replacement	0	0%	0	Because it is obsolete and requires extensive annual maintenance.
Flin Flon Border new 115kV Station	17	100%	17	To provides necessary facilities to terminate 115 kV lines from Cliff Lake and Ross Lake stations and from Island Falls (SaskPower).
Pine Fall Protection Changes for Lines PA1 and PA2	29	0%	0	The relay system is obsolete and there are no spares available.
Roblin South Station 230 KV Reactor Addition	1,816	0%	0	To maintain 230 kV voltage limits within 95-105% during normal and contingency conditions.
T/L Thermal Rating Verification (W.I.R.E. Services)	1,018	0%	0	To complete missing information on the "conductor thermal rating" list issued by Transmission Line Design to System Performance.
Transmission System Metering	1,215	0%	0	To replace obsolete strip chart recorders and indicating demand meters with digital meters, and install them at 11 new sites to complete the metering system for transmission tariff purposes.
Transmission Line Vibration Study	51	0%	0	To monitor aeolian and motion arising from extreme weather events on the sky wire of line D54C.

Rosser-St.James 115kV TL Property Acquisition	465	0%	0	To allow MH to control the use of the land encumbered by the St. James 115 kV T/L. Ownership allows MH to benefit under its secondary land use program from the potential for parking revenue.
Target transferred from VP:				
Dorsey 500kV Spare Transformer Cold Standby	777	100%	777	To allow for design and construction of pad foundation for a single phase spare transformer at Dorsey.
Nelson River Crossing Strobe Light Replacement	478	0%	0	To replace antiquated strobe light system.
St. Vital Battery Banks	184	100%	184	Larger battery banks are required due to recent additions to St. Vital station.
Star Lake SK1-1 vacrupter switch	84	0%	0	To maintain short customer interruptions during switching.
Subtotal	**6,825**		**1,784**	
Subtransmission				
Jenpeg Terminal 66 kV Changes	40	100%	40	Required for operation and protection of a new line to Norway house.
Glenboro South Station Bank 3 Addition	105	100%	105	In stall a 230-66 kV transformer to deal with load growth in Glenboro South 66 kV system
Richer South 230-66kV Emergency Transformer	0	100%	0	To provide a second contingency backup to all 230-66 kV transformers on the MH system.
Target transferred from VP:				
Assiniboine Wilkes Ave - 115-24kV Transformer Addition	261	100%	261	To support load growth in the area and provide backup to other 24 kV stations nearby.
Portage South Station 66kV Breaker Addition	258	100%	258	Associated with the 66 kV line from Portage South to Portage Westco Drive which deals with load growth
Portage South-Portage Westco Drive 66kV Line	164	100%	164	Construction of the new 16 km, 66 kV line will off-load the line 84 whose limit is being approached.
Selkirk MRM Primary Metering	55	0%	0	
Selkirk MRM Protection	51	0%	0	
Portage South Station Hot Standby	1,385	100%	1,385	To replace the 230-66 kV bank #1 in the event of its failure in order to quickly restore supply to large customers including new loads.
Subtotal	**2,319**		**2,213**	
TP&D Non-blanket -- Transmission	**6,825**		**1,784**	
TP&D Non-blanket -- Subtransmission	**2,319**		**2,213**	
TP&D Non-blanket -- Transmission + Subtransmission	**9,144**		**3,997**	TP&D non-blanket budget is about 44% capacity-related

Table B.5. Analysis of 2003/04 DP&D Domestic Budget -- Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Comments
			in $1,000	
1) Brandon				
Station	**736**	75%	552	
Distribution				
S/T Adds & Mods	0	75%	0	
S/T System - Ice Melting	0	0%	0	
Street Lighting	156	0%	0	
Highway Changes	669	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	2,892	80%	2,314	
Customer Service	1,978	50%	989	Arbitrary assumption
New & Upgrd Feeders	0	80%	0	
Underground Residential Dist	192	100%	192	
Adjustment made to Dist Const Activity Rate	0	0%	0	
Defective Cable Replacements	0	0%	0	
Subtotal	**5,887**		**4,047**	
2) Selkirk				
Station	**1,200**	75%	900	
Distribution				
S/T Adds & Mods	400	63%	250	
S/T System - Ice Melting	250	0%	0	
Street Lighting	500	0%	0	
Highway Changes	800	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	3,900	75%	2,925	
Customer Service	2,150	50%	1,075	Arbitrary assumption
New & Upgrd Feeders	0	75%	0	
Underground Residential Dist	50	100%	50	
Duct Systems	0	0%	0	
Defective Cable Replacements	500	0%	0	
Subtotal	**8,550**		**5,200**	
3) Winnipeg				
Station	**825**	75%	619	

Distribution				
S/T Adds & Mods	100	10%	10	
S/T System - Ice Melting	0	0%	0	
Street Lighting	350	0%	0	
Highway Changes	0	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	4,500	85%	3,825	
Customer Service	1,500	50%	750	Arbitrary assumption
New & Upgrd Feeders	0	85%	0	
Underground Residential Dist	700	100%	700	
Carryover and Unreleased Projects	0	0%	0	
Defective Cable Replacements	500	0%	0	
Subtotal	**7,650**		**5,904**	
Total DP&D Blankets -- Station*	**2,761**		**2,071**	Station blanket budget is about 75% capacity-related
Total DP&D Blankets -- Distribution*	**22,087**		**15,150**	Distribution blanket budget is about 69% capacity-related
Total DP&D Blankets	**24,848**		**17,221**	DP&D blanket budget is about 69% capacity-related

***Notes:**

1) "Station" is part of "subtransmission" in this marginal cost study (Report SPD 04/05).
2) "Distribution" is interpreted as "distribution-circuit" in this marginal cost study (Report SPD 04/05).

Table B.6. Analysis of 2003/04 DP&D Domestic Items -- Approved Non-Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1000)	Capacity-Related Portion		Justifications or Comments
			in $1000	
1) Bdn Distribution Planning & Design Non-Blankets				
Station				
Benito Station Rebuild	0	0%	0	Due to poor conditions
Holland 66-8.32kv Stn 03-833	0	0%	0	Due to poor conditions
Gladstone Stn Salvage	52	50%	26	A new station has been built. Existing station is old, and inadequate in space for adding larger transformers.
Boissevain Stn 66kV Rebuilt	1	0%	0	Due to its poor conditions
Rorketon 66-24.9/14.4 kV Station	795	0%	0	Construct a new single banks station near the existing site due to various operating and maintenance concerns
Brandon 65th St East Bank Add	0	100%	0	Addition of a 115-24.9 kV bank will address the inadequate capacity concern
74437 - Flin Flon Ross L. Neut Reactor	0	0%	0	For equipment and operator safety concerns
Holland 66-8.32kv Stn	-13	0%	0	Existing station is in poor condition
Dauphin Vermillion Stn Bk Sal & Mobile	45	100%	45	To serve more load
Dauphin Second St Stn Convert to 12 KV	9	50%	4	Existing switchgear is in poor condition, etc. Better spare bank locations for future load growth
Brandon Highland Mobile Provision	0	100%	0	To provide for mobile connection
Subtotal	**887**		**75**	
Distribution				
DAUPHIN 2ND ST. CONVERSION	8	0%	0	Part of two year plan to convert Dauphin to 12 kV
L74 Rebuild Killarney - Ninette	-12	0%	0	L74 is old and is in poor condition. A new 66 kV line will address all old-age related issues
Prospector Corner 66-24.9kv Dist. Supply	525	100%	525	To reduce feeder losses
Stage 2 - Dauphin Second St. Conversion	3	50%	2	Existing switchgear is in poor condition, etc. Better spare bank locations for future load growth
66kV Line 85 Rebuild and GE12-1	-72	0%	0	Due to poor condition with old poles, etc.
MacGregor S.I. Fdr MR12-4 & New MR12-3	-15	50%	-8	New feeder will improve voltage and losses

FLIN FLON ROSS LAKE NEW FEEDER	-2	100%	-2	To meet a demand of 1500 kVA (new load)
L52 66kV Rebuild Pilot Mound - Swan Lake	143	0%	0	Due to rotten arms, rottens poles, etc.
66kV TAP PELICAN RAPIDS CORNER DSC	479	100%	479	To deal with load increase at Pelican Rapids
MAFEKING TO PELICAN RAPIDS CORNER 66 KV	917	100%	917	To deal with load increase at Pelican Rapids
SHOAL LAKE RURAL REBUILD	1,576	50%	788	Existing 33-8 kV station is in poor condition. As a result of upgrading 8 kV distribution to 12 kV and subtransmission to 66 kV, load capability will be increased
Subtotal	**3,549**		**2,701**	
Total Bdn Distribution Planning & Design Non-Blankets	**4,436**		**2,775**	
2) Selkirk Distribution Planning & Design Non-Blankets				
Station				
Parkdale Stn-Bnk Add'n	0	100%	0	To deal with load growth
038374 NIVERVILL STN CON NEW 66-12KV STN	8	0%	0	Deficiencies and condition of the existing station results in need for a new station
Ilford Station	0	0%	0	Many deficiencies cause serious operating problems and safety concerns
Vivian Stn-Improvement	15	50%	7	To address safety concerns and also provide for mobile connection
Sarto Station Bank Replacement	1	100%	1	For higher station capacity to accommodate load growth
WINKLER NORTH STATION BANK ADDITIO	-202	100%	-202	To handle load growth
Winkler Market Bank Replacement	0	100%	0	To insolate harmonics produced at Monarch industries, and also provide transformer redundancy
East Selkirk Stn.-Disconnects Repl	-54	0%	0	For safety concerns
Cross Lake Station ISD 2003-09-30	962	100%	962	Install a 3rd transformer
Gimli Station - New Station	305	50%	153	The existing station is too old. The 2nd bank in new station provides one level of redundancy into the system
Gillam Station-New Station	481	50%	240	The existing station is too old. The 2nd bank in new station provides one level of redundancy into the system
06458 STEINBACH 1st AVE ACR REPLACEMENT	413	0%	0	
Stony Mountain Stn - Site acquisition/Eng	102	100%	102	For new 115-12 kV station to deal with load growth

Subtotal	**2,031**		**1,264**	
Distribution				
Rebuild Line 64 Fort Alexander	591	50%	295	Wpg River caused erosion of river banks that results in distributed soil and leaning poles. A new school requires feeder extension and line modification as well.
Brokenhead-Beausejour N 33kV	0	0%	0	For safety concerns
KOMARNO FDR KO08-2 CONVER INWOOD	0	0%	0	To address the low voltage problem
NORWAY HOUSE SCHOOL	1,359	0%	0	This project is customer service for Norway House Cree Nation.
STAR LAKE FDR STL12-1 RELOCATION	-7	0%	0	To improve reliability, service and power quality.
Inwood Conversion - Stage 2 N/B	141	0%	0	To address the low voltage problem
04326 INWOOD CONVERSION - STAGE 3 N/B	432	0%	0	To address the low voltage problem
L#20 Stuartb-Vita S/T	669	50%	334	To increase reliability and also reduce losses.
THOMPSON WESTWOOD ACRs	-59	0%	0	
WINKLER MARKET 8kV CONVERSION WM8-	0	0%	0	To maintain operating and safety standards
06200 WABOWDEN DSC'S NON-BLANKET	511	100%	511	Install 2 new 66-12 kV distribution supply centers to replace existing Wabowden station
PINEY SUPPLY CENTRE - NON-BLANKET	683	0%	0	For safety concerns
06989 HADISHVILLE DSC INSTALLATION	0	0%	0	For safety concerns
06990 MEDIKA DSC INSTALLATION	0	100%	0	Construct new distribution supply center
Subtotal	**4,319**		**1,141**	
Total Selkirk Distribution Planning & Design Non-Blankets	**6,351**		**2,405**	
3) Winnipeg Distribution Planning & Design Non-Blankets				
Station				
Court - Install 115 12kV Bank	0	100%	0	Installation of a 2nd bank provides firm capacity
Augier 115-12kV Bus Rebild	489	0%	0	For safety concerns
Birds Hill Station Property	-17	0%	0	
Transcona RAVELSTONE STN - PROPERTY ACQUISITION	507	100%	507	For the future Ravelstone Station to accommodate load growth
Subtotal	**979**		**507**	
Distribution				
12kV Padmount Feeder Capacitors	45	0%	0	To complete outstanding work and deficiencies related to installation of various feeder capacitors
EK Spgfld Add 66-12kV Bank #2	-10	100%	-10	Provides for additional 12 kV capacity for north-east Winnipeg

Winnipeg 63.5kV Network T/L Refurbish	-42	0%	0	To ensure safe operating ground clearances
Oak Bluff 12kv S.I.	-1	100%	-1	Facilities are required to integrate the new Oak Bluff station into the distribution system
Kitchen Craft 1180 Springfield	0	100%	0	To meet the increased load requirement
Pembina Station Rebuild	312	0%	0	Transformer replacement to maintain reliability standards
MAPLES SILICONE CABLE INJECTION	418	0%	0	To revitalize existing cables in Maples area using a technique of cable injection
Dakota-Upgrade 731DK Feeder	214	100%	214	To relieve heavily loaded feeders DK731, etc.
Subtotal	**937**		**203**	
Total Winnipeg Distribution Planning & Design Non-Blankets	**1,916**		**710**	
Total DP&D Non-Blankets -- Station*	**3,898**		**1,846**	
Total DP&D Non-Blankets -- Distribution*	**8,805**		**4,045**	
Total DP&D Non-Blankets -- (Station + Distribution)	**12,703**		**5,891**	DP&D non-blanket budget is about 46% capacity-related

***Notes:**

1) "Station" is part of "subtransmission" in this marginal cost study (Report SPD 04/05).
2) "Distribution" is interpreted as "distribution-circuit" in this marginal cost study (Report SPD 04/05).

Table B.7. T&D Expansion Plan — Load Growth Related Expenditures in $1,000 (Including Effect of Inflation)

k	Fiscal Year	T&D Domestic Budget	TP&D and DP&D Domestic Budget	Capacity-Related Domestic Budget	Transmission			Distribution: Subtransmission			Distribution: Distribution-circuit			Total T&D
					Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	
			(A)×(75%)	(B)×(50%)		(C)×(5%)	(D)+(E)		(C)×(25%)	(G)+(H)		(C)×(70%)	(J)+(K)	(F)+(I)+(L)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
0	2004/05	81,300	60,975	30,488	526	1,524	2,050	0	7,622	7,622	0	21,341	21,341	31,014
1	2005/06	83,100	62,325	31,163	2,580	1,558	4,138	0	7,791	7,791	0	21,814	21,814	33,743
2	2006/07	85,100	63,825	31,913	9,074	1,596	10,670	1,583	7,978	9,561	0	22,339	22,339	42,570
3	2007/08	86,900	65,175	32,588	20,182	1,629	21,811	9,155	8,147	17,302	0	22,811	22,811	61,925
4	2008/09	88,900	66,675	33,338	31,403	1,667	33,070	7,598	8,334	15,932	0	23,336	23,336	72,339
5	2009/10	90,800	68,100	34,050	32,156	1,703	33,859	20,213	8,513	28,726	0	23,835	23,835	86,419
6	2010/11	93,100	69,825	34,913	48,294	1,746	50,040	7,428	8,728	16,156	0	24,439	24,439	90,635
7	2011/12	93,600	70,200	35,100	48,914	1,755	50,669	0	8,775	8,775	0	24,570	24,570	84,014
8	2012/13	94,300	70,725	35,363	13,892	1,768	15,660	0	8,841	8,841	0	24,754	24,754	49,255
9	2013/14	97,600	73,200	36,600	28,867	1,830	30,697	142	9,150	9,292	0	25,620	25,620	65,609

Table B.8. T&D Expansion Plan — Load Growth Related Expenditures in $1,000 (Not Including Effect of Inflation)

					Transmission			Distribution						
								Subtransmission			Distribution-circuit			
k	Fiscal Year	T&D Domestic Budget	TP&D and DP&D Domestic Budget	Capacity-Related Domestic Budget	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Total T&D
			(A)×(75%)	(B)×(50%)		(C)×(5%)	(D)+(E)		(C)×(25%)	(G)+(H)		(C)×(70%)	(J)+(K)	(F)+(I)+(L)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
0	2004/05	81,300	60,975	30,488	526	1,524	2,050	0	7,622	7,622	0	21,341	21,341	31,014
1	2005/06	81,471	61,103	30,551	2,529	1,528	4,057	0	7,638	7,638	0	21,386	21,386	33,081
2	2006/07	81,795	61,347	30,673	8,722	1,534	10,255	1,187	7,668	8,856	0	21,471	21,471	40,582
3	2007/08	81,888	61,416	30,708	19,018	1,535	20,553	6,866	7,677	14,543	0	21,496	21,496	56,592
4	2008/09	82,130	61,597	30,799	29,012	1,540	30,551	5,699	7,700	13,398	0	21,559	21,559	65,509
5	2009/10	82,240	61,680	30,840	29,125	1,542	30,667	15,160	7,710	22,870	0	21,588	21,588	75,125
6	2010/11	82,670	62,003	31,001	42,884	1,550	44,434	5,571	7,750	13,321	0	21,701	21,701	79,456
7	2011/12	81,484	61,113	30,557	42,583	1,528	44,110	0	7,639	7,639	0	21,390	21,390	73,139
8	2012/13	80,484	60,363	30,182	11,857	1,509	13,366	0	7,545	7,545	0	21,127	21,127	42,038
9	2013/14	81,667	61,250	30,625	24,155	1,531	25,686	107	7,656	7,763	0	21,438	21,438	54,886

Notes:

1). Inflation or escalation rate j = 2%

Appendix C

– Existing Avoided T&D Costs

5.5 Conclusions

- The significant variation in Transmission Cumulative Savings (Table 1 of Appendices G and I) is due to the discrete nature of the Major Items included in the analysis. If a forecast of future Major Transmission Items Capital requirements was used, a more consistent result would be expected. Such a forecast does not exist at the present time.

- Transmission and Distribution capital requirements are generally well determined for the initial 10 year budget period. Beyond 10 years, few specific plans are formalized in the budget. For this reason, T&D Avoided Costs were determined for only a maximum 25 year period.

- In terms of levelized cost savings, the results are consistent between the two D.S.M. programs which were evaluated.

- Considering the variation between the 100 MW and 200 MW DSM programs, it is recommended that the following costs be used as representative of T&D Avoided Costs.

Distribution	\$11/kW/YR (\$1990)
Transmission	\$11/kW/YR (\$1990)
TOTAL	\$22/kW/YR (\$1990)

- NUG's or DSM programs which are located in or targetted to specific areas of the system may have significantly different T&D Avoided Costs than those determined in this report.

  Specific programs will require specific determinations of potential savings.

APPENDIX 1: DISTRIBUTION SYSTEM AVOIDED COSTS FOR THE 100MW DSM PROGRAM

TABLE 6: CALCULATION OF LEVELIZED AVOIDED COSTS DUE TO D.S.M.

YEAR	CAPITAL REQUIREMENTS 1995 PRESENT VALUE		DIFFERENCE IN PRESENT VALUE	CUMULATIVE PRESENT VALUE SAVING ($M)	LEVELIZING FACTORS (MW)	LEVELIZED AVOIDED COST ($/KW/YR 1995)
	WITHOUT D.S.M.	WITH D.S.M.				
1995/96	$27.25	$27.25	$0.00	$0.00	32.00	
1996/97	$26.02	$26.02	$0.00	$0.00	46.56	
1997/98	$24.81	$24.81	$0.00	$0.00	62.29	
1998/99	$23.67	$21.18	$2.49	$2.49	71.19	
1999/00	$22.63	$20.25	$2.38	$4.87	74.16	
2000/01	$21.51	$19.24	$2.26	$7.14	74.33	
2001/02	$20.50	$18.34	$2.16	$9.30	73.56	
2002/03	$19.52	$17.47	$2.05	$11.35	71.99	
2003/04	$18.56	$16.61	$1.95	$13.30	70.39	
2004/05	$17.73	$15.87	$1.87	$15.17	69.41	
2005/06	$16.89	$15.11	$1.78	$16.95	68.34	
2006/07	$16.12	$14.42	$1.70	$18.65	67.21	
2007/08	$15.34	$13.72	$1.61	$20.26	66.02	
2008/09	$14.62	$13.08	$1.54	$21.80	64.79	
2009/10	$13.89	$12.42	$1.46	$23.26	63.51	
2010/11	$13.19	$11.81	$1.39	$24.65	62.20	
2011/12	$12.54	$11.22	$1.32	$25.97	60.86	
2012/13	$11.91	$10.66	$1.25	$27.22	59.50	
2013/14	$11.32	$10.13	$1.19	$28.41	58.12	
2014/15	$10.75	$9.62	$1.13	$29.55	56.74	
RESIDUAL VALUE AT THE END OF THE STUDY PERIOD	($182.82)	($165.85)	($16.97)	$12.58		$9.88

APPENDIX 2: TRANSMISSION SYSTEM AVOIDED COSTS FOR THE 100MW DSM PROGRAM

TABLE 6: CALCULATION OF LEVELIZED AVOIDED COSTS DUE TO D.S.M.

YEAR	CAPITAL REQUIREMENTS WITHOUT D.S.M. 1995 PRESENT VALUE	CAPITAL REQUIREMENTS WITH D.S.M. 1995 PRESENT VALUE	DIFFERENCE IN PRESENT VALUE	CUMULATIVE PRESENT VALUE SAVING ($M)	LEVELIZING FACTORS (MW)	LEVELIZED AVOIDED COST ($/KW/YR 1995)
1995/96	$14.95	$12.75	$2.20	$2.20	32.00	
1996/97	$14.70	$14.17	$0.53	$2.73	46.56	
1997/98	$32.34	$13.96	$18.39	$21.12	62.29	
1998/99	$46.05	$29.55	$16.50	$37.62	71.19	
1999/00	$46.29	$42.71	$3.59	$41.21	74.16	
2000/01	$9.80	$42.91	($33.11)	$8.09	74.33	
2001/02	$9.36	$8.37	$0.99	$9.08	73.56	
2002/03	$9.34	$7.91	$1.43	$10.51	71.99	
2003/04	$11.60	$7.52	$4.08	$14.58	70.39	
2004/05	$13.79	$7.58	$6.21	$20.79	69.41	
2005/06	$11.22	$9.66	$1.56	$22.35	68.34	
2006/07	$16.72	$11.69	$5.03	$27.38	67.21	
2007/08	$26.37	$9.41	$16.96	$44.34	66.02	
2008/09	$16.44	$14.40	$2.04	$46.38	64.79	
2009/10	$6.17	$23.14	($16.98)	$29.40	63.51	
2010/11	$5.86	$14.23	($8.37)	$21.03	62.20	
2011/12	$5.57	$4.98	$0.59	$21.62	60.86	
2012/13	$5.29	$4.73	$0.56	$22.17	59.50	
2013/14	$5.02	$4.50	$0.53	$22.70	58.12	
2014/15	$4.77	$4.27	$0.50	$23.21	56.74	
RESIDUAL VALUE AT THE END OF THE STUDY PERIOD	($155.53)	($148.91)	($6.63)	$16.58		$13.02

Table C.1. A Brief Look at Capital Cost v.s. Load Growth in 1990 Voided Cost Study

	k	Fiscal Year	Peak (MW)	Load Growth (MW/Year)	Load Growth Discounted @6%	Distribution Capital Costs (Base 1995 Dollars) (in Millions of Dollars)	Present Value of Distribution Capital Costs @6%	Transmission Capital Costs (Base 1995 Dollars) (in Millions of Dollars)	Present Value of Transmission Capital Costs @6%
	0	1995/96	3,988			27.25		12.75	
	1	1996/97	4,055	67	63	27.38	26	12.71	12
	2	1997/98	4,161	106	94	27.48	24	12.70	11
	3	1998/99	4,236	75	63	27.60	23	12.66	11
	4	1999/00	4,296	60	48	27.77	22	12.71	10
	5	2000/01	4,365	69	52	27.78	21	12.65	9
	6	2001/02	4,441	76	54	27.78	20	12.72	9
	7	2002/03	4,509	68	45	27.93	19	12.65	8
	8	2003/04	4,578	69	43	27.95	18	12.66	8
	9	2004/05	4,645	67	40	28.10	17	12.63	7
	10	2005/06	4,714	69	39	28.18	16	12.65	7
	11	2006/07	4,783	69	36	28.30	15	12.63	7
(R1)	Average load growth rate (MW/Year) =			72					
(R2)					576				
(R3)							219		
(R4)									100
	Incremental Distribution Cost per kW of Load Growth ($/kW/Year, 1995 dollars) (1000×R3/R2) =						380		
	Incremental Distribution Cost per kW of Load Growth ($/kW/Year, 1990 dollars) =						284		
	Incremental Transmission Cost per kW of Load Growth ($/kW/Year, 1995 dollars) (1000×R4/R2) =								173
	Incremental Transmission Cost per kW of Load Growth ($/kW/Year, 1990 dollars) =								130

References:

[D-1] W. Pyl, "Transmission and Distribution System Avoided Costs", Memo to File, File 2-14-1, AC Transmission Planning Division, Manitoba Hydro, March 20, 1990.

REFERENCE:

GAC/MH I-39, Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

Regarding the calculation of marginal transmission and distribution costs described in the Attachment, please provide the following information:

a) Indicate whether Manitoba Hydro includes in load growth-related expenditures, the costs of projects planned to serve load growth in the study period but completed before year 1 or 2016/2017.

b) Indicate whether Manitoba Hydro includes in load growth-related expenditures, the costs of projects planned to meet load growth during the study period but started before year 1 or 2016/2017.
   i. If so, does Manitoba Hydro include all expenditures on the project, or only expenditures in the study period?

c) Indicate whether Manitoba Hydro includes as load growth-related expenditures on projects that are planned to meet to serve load growth in the study period, committed before the start of the study period but started on year 1 or after.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro does not include costs before year 1 as it is assumed they cannot be avoided.

b) Costs before year 1 are not included, but subsequent years (year 1+) are included. This includes only costs in the study period not including year 0 costs.

c) Confirmed. Costs only include committed projects that start from year 1 and on during the study period.

REFERENCE:

GAC/MH I-39, Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

Regarding the calculation of marginal transmission cost described in the Attachment, please provide the following information:

a) Specify the source of the load forecast presented in Table A on page 10 and in Appendix A;

b) Indicate whether the load forecast used in the calculation described in the Attachment:
   i. consists of domestic load only,
   ii. consists of domestic load plus exports; or
   iii. something else. If so, explain what loads are included in the forecast.

c) Indicate whether the forecasted peak loads in Table A are:
   i. measured at the Common Bus,
   ii. measured at the meter, or
   iii. something else. If so, what.

d) Indicate whether the forecasted peak loads in Table A are:
   i. Maximum winter peak load;
   ii. Average of winter monthly peaks,
   iii. Average of winter and summer peaks,
   iv. Something else. If so, explain what.

e) Indicate whether MH assumes in Appendix B, Table E.3 that the Domestic Budget for Reliability: Outage-Related purposes are 0% load-related.

f) Explain whether load growth can increase the likelihood of outages and therefore the need for Reliability: Outage-Related projects.

g) For each project in Table E.1, provide the % of expenditures that are reliability-related but not load-related.

h) Provide the basis for the assumption that the portion of the Domestic Budget that is load-related in 2015/16 is representative of expenditures throughout the Study Period.

i) Reconcile the marginal transmission cost estimate of $42.33/kW.year in the Attachment with the estimate of 0.56 cents/kW.h in Figure 8.14 in Tab 8, page 31.

j) Specify where in the Attachment by page number, if anywhere, losses are incorporated in the estimate of marginal transmission cost.

RATIONALE FOR QUESTION:

RESPONSE:

a) The load forecast is generated from the 2015 Electric Load Forecast, provided by the Market Forecast and Load Research department. Table A is generated by using the gross total peak, and subtracting 25 MW of station service load to produce the net total peak. Note that the 2015 transmission marginal cost report references the 2014 Electric Load Forecast, which is an error as the 2015 Electric Load Forecast was the actual data used.

b) The load forecast consists of net domestic load only, and does not include station service load.

c) The forecasted peak loads are provided from the generation source.

d) The forecasted peak loads are maximum winter peak load.

e) Reliability: Outage-Related is spending that addresses outage-related reliability of the transmission system including system emergencies and regulatory compliance. A project could have a split of categories that would include Reliability: Outage-Related and Reliability: Load-Related. This means that spending for Domestic Budget items for Reliability: Outage-Related purposes are 0% load-related as they would be captured under Reliability: Load-Related.

f) Load growth isn't expected to increase the likelihood of outages such that they would be captured as a Reliability: Outage-Related domestic project.

g) This data is no longer available. Reliability project values that aren't directly load related are considered out of scope for the Transmission Marginal Cost study so they are not included in the information of the report.

h) The 2015/16 Domestic Program budget amounts, including Reliability: Load Related expenditures, are based on historical actual expenditures.

i) Please see Manitoba Hydro's response to Coalition/MH II-34a-c for the reconciliation of the Transmission Marginal Cost.

j) Transmission losses are not discussed within the marginal transmission loss estimate report. Please see Manitoba Hydro's response to Coalition/MH II-34a-c for an explanation of how transmission marginal costs are added.

REFERENCE:

GAC/MH I-39, Attachment, page 23 and response to Coalition/MH I-174, Attachment 2, Attachment 72

PREAMBLE TO IR (IF ANY):

The marginal transmission cost analysis assumes the Stanley Area 115kV Load Migration to 230kV Supply Network Phase III - Third Bank project is 48% load-related. The project justification document provided in Coalition/MH I-174, Attachment 2 indicates that the other 52% is the cost of decommissioning of two stations and lines no longer needed after installation of a third transformer at Stanley Station.

QUESTION:

Please explain whether the decommissionings would be needed if there were no load growth in the Stanley area.

RATIONALE FOR QUESTION:

RESPONSE:

The decommissioning of YF11 and YM31 is related to the age, condition and safety concerns regarding the 115 kV assets supplying the Stanley area. This portion is unrelated to the load growth in the Stanley area. Instead of rebuilding the supply lines, transferring the load to the 230 kV system and decommissioning the 115 kV system was considered the lower cost alternative.

REFERENCE:

GAC/MH I-39, Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

Regarding the calculation of marginal distribution cost described in the Attachment, please provide the following information:

a) Reconcile the marginal distribution cost estimate of $58.12/kW.year in the Attachment with the estimate of 0.87 cents/kW.h in Figure 8.14 in Tab 8, page 31.

b) Reconcile the statement on page 37 that the capacity-related portion of projects >$2 million "was determined to be" 53.3% with the result reported in Table B.1 on page 45 that the capacity-related portion is 37.7%.

c) Reconcile the statement on page 37 that the capacity-related portion of total Distribution Capital Expenditures is on average 52% with the result reported in Table B.3 on page 46 that the capacity-related portion is 46%.

d) Provide project by project, the analysis of distribution projects over $2 million, in the same form as provided for major transmission projects in Table E1 on pages 22-24 of the Attachment.

e) Provide the calculations underlying Table B.3 on page 46, including all workpapers and Excel spreadsheets (with formulas intact).

f) Regarding the statement on page 37 that projects are treated as 0% load-related if driven by reliability concerns,
    i. Explain whether reliability problems such as increasing likelihood of outages can be caused by load growth,

ii. Provide the total (in $ million and %) of expenditures on projects >$2 million that are considered reliability-related and not load-related.
iii. Provide a list of projects >$2 million that are considered partly or entirely reliability-related and not load-related.
iv. Provide the total (in $ million and %) of expenditures on distribution domestic programs that are considered reliability-related and not load-related

g) Indicate whether the forecasted system peak loads in Table 2 on page 36 consist of domestic load only.

h) Provide the forecasted system peak loads in Table 2 on page 36 net of the loads of customers that are not served by the distribution system.
   i. Specify where in the Attachment, by page number, if anywhere, losses are incorporated in the estimate of marginal distribution cost.

RATIONALE FOR QUESTION:

RESPONSE:

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

b) The reference to "capacity-related portion of projects >$2 million "was determined to be" 53.3%" was reported in error. The capacity-related portion is 37.7%, and this number is used for generating the marginal cost.

c) The reference to "the capacity-related portion of total Distribution Capital Expenditures is on average 52%" was reported in error, the capacity-related portion is 46%, and this number is used for generating the marginal cost.

d) Please see the Table on Page 4-8 of this response.

e) CEF15 column in Table B.3 is multiplied by 46% to generate all capacity related expenditures. All relevant calculations are included in the report.

f) Regarding the statement on page 37 that projects are treated as 0% load-related if driven by reliability concerns, please see the following responses:
   i. Load growth isn't expected to increase the likelihood of outages.
   ii. Reliability project values that are not directly load related are considered out of scope for the Distribution Marginal Cost Study.
   iii. Part or entire reliability project values that are not directly load related are considered out of scope for the Distribution Marginal Cost Study.
   iv. Distribution domestic reliability programs that are not load related are considered out of scope for the Distribution Marginal Cost study.

g) The forecasted system peak loads in Table 2 on page 36 only consist of domestic load.

h) The forecasted system peak loads in Table 2 on page 36 only consist of domestic load.
   i. Distribution losses are not discussed within the 2015 Distribution Marginal Cost Estimate report. Please see Manitoba Hydro's response to Coalition/MH II-35a-c.

d) Analysis of the 2015/16 Distribution Major Projects > $2.0M for Marketing and Customer Service (MCS) is provided below:

(in million dollars-Constant 2016 CDN$)

Projects	Justification	% Capacity Related	Owning B.U.	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	Source	Total
Brandon Crocus Plains 115 - 25kV Bank Addition	Capacity Enhancement	100%	MCS	0.012	0.013	0.014	0.486	0.014	4.763					Approved Outlook	5.302
Carmen 8th Ave DSC	Capacity Enhancement	100%	MCS		0.200	3.800								Approved Outlook	4.000
Corbett Road New 115/12 kV DSC	Capacity Enhancement	100%	MCS	0.050	0.148	1.498	2.498	2.498							6.692
Elie Station Bank Replacement	Capacity Enhancement	100%	MCS	0.010	0.200	2.202								Approved Outlook	2.412
Enbridge Gretna Capacitor Bank Addition	Capacity Enhancement	100%	MCS	0.050	0.384	2.066								Approved Outlook	2.500
Hochfeld DSC	Capacity Enhancement	100%	MCS	2.300										Approved Outlook	2.300
Iles des Chenes New DSC	Capacity Enhancement	100%	MCS	0.250	2.235	1.000	1.004							Approved Outlook	4.489
Kleefeld DSC	Capacity Enhancement	100%	MCS	0.320										Approved Outlook	0.320
La Salle DSC Supply & Dist. Feeders	Capacity Enhancement	100%	MCS		0.010	1.700									1.710
Landmark DSC (Site & Land)	Capacity Enhancement	100%	MCS			3.500									3.500
Lee River DSC	Capacity Enhancement	100%	MCS	0.030	0.030	3.682									3.742
Lockport DSC	Capacity Enhancement	100%	MCS	2.250										Approved Outlook	2.250
Martin New 66-4kV Station	Capacity Enhancement	100%	MCS	4.071										Approved Outlook	4.071
McTavish DSC & Feeder Conversion	Capacity Enhancement	100%	MCS	0.540										Approved Outlook	0.540
Middlechurch Stn Bank & Feeder Additions	Capacity Enhancement	100%	MCS	0.020	0.101	2.014	3.021								5.156

Projects	Justification	% Capacity Related	Owning B.U.	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	Source	Total
Morden Ninth Station Bank Addition	Capacity Enhancement	100%	MCS		0.500	2.000									2.500
Morden Thornhill DSC	Capacity Enhancement	100%	MCS		0.200	0.200	3.600								4.000
Norway House Station Bank Addition	Capacity Enhancement	100%	MCS	0.090	2.900	1.000								Approved Outlook	3.990
Notre Dame de Lourdes DSC	Capacity Enhancement	100%	MCS	3.000	0.500									Approved Outlook	3.500
Oak Bluff Bank Addition	Capacity Enhancement	100%	MCS	0.005	0.100	2.300									2.405
Oakbluff Stn Bank & Feeder Addition	Capacity Enhancement	100%	MCS	0.200	0.200	2.000									2.400
Outlets of Seasons Development Expansion	Capacity Enhancement	100%	MCS	1.250	1.950									Approved Outlook	3.200
Portage la Reine Station Voltage Conversion	Capacity Enhancement	100%	MCS			2.600									2.600
Selkirk North DSC	Capacity Enhancement	100%	MCS	0.040										Approved Outlook	0.040
Skelding DSC	Capacity Enhancement	100%	MCS	0.200	2.300									Approved Outlook	2.500
Ste. Agathe Station Bank Addition	Capacity Enhancement	100%	MCS	0.210	0.090	1.752								Approved Outlook	2.052
Steinbach North & South DSC's	Capacity Enhancement	100%	MCS	4.000	1.400									Approved Outlook	5.400
Stony Creek DSC	Capacity Enhancement	100%	MCS		0.050	2.500									2.550
Teulon East Stn Bank Upgrade	Capacity Enhancement	100%	MCS			3.500									3.500

Projects	Justification	% Capacity Related	Owning B.U.	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	Source	Total
Tyndall DSC	Capacity Enhancement	100%	MCS	2.200	1.650									Approved Outlook	3.850
Waverley West Supply - Stage 2 (DSCs)	Capacity Enhancement	100%	MCS	4.354										Approved Outlook	4.354
Winkler Eastview Dr DSC	Capacity Enhancement	100%	MCS		0.100	0.200	3.700								4.000
Winkler West DSC	Capacity Enhancement	100%	MCS	4.000										Approved Outlook	4.000
York Stn-Bank 1,3,5 & Switch Gear Addition	Capacity Enhancement	100%	MCS	11.246	6.779									Approved Outlook	18.025
Gimli West Stn GW08-5 & CW08-8 Conversion	Capacity Enhancement	90%	MCS	0.100	1.900									Approved Outlook	2.000
Interlake 66kV System Improvement Work	Capacity Enhancement	75%	MCS	0.430	3.490	0.760	1.950							Approved Outlook	6.630
Portage South 66kV L54 & L84 Upgrade	Capacity Enhancement	75%	MCS			3.000	1.400							Approved Outlook	4.400
Victoria Beach DSC	Capacity Enhancement	70%	MCS	0.400	3.200									Approved Outlook	3.600
William Avenue - New Ductline	Capacity Enhancement	60%	MCS	6.689	7.999									Approved Outlook	14.688
Alexander 66-25kV DSC & Conversion	Capacity Enhancement	50%	MCS	0.050	1.850									Approved Outlook	1.900
Alexander 8-25kV Voltage Conversion	Capacity Enhancement	50%	MCS		3.145										3.145
Bdn Patricia/Alexander Load Transfers	Capacity Enhancement	50%	MCS			0.500									0.500
Brandon Victoria Bank Replacement & Brandon Louise Station Conversion & Salvage	Capacity Enhancement	50%	MCS				2.000	2.000							4.000
Brandon West 4kV - 12kV Conversion	Capacity Enhancement	50%	MCS	2.300	2.000									Approved Outlook	4.300
Gimli West GW08-11 & -09 25kV Conversion	Capacity	50%	MCS	0.600										Approved	0.600

Projects	Justification	% Capacity Related	Owning B.U.	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	Source	Total
	Enhancement													Outlook	
Glenboro Town 8-25kV Conv'n&8kV Stn Salv	Capacity Enhancement	50%	MCS	1.525										Approved Outlook	1.525
Heaslip DSC & 8/24.9kV Conversion	Capacity Enhancement	50%	MCS	0.050	1.700	2.000									3.750
Neepawa Area 66kV System Improvement	Capacity Enhancement	50%	MCS	4.110	1.000									Approved Outlook	5.110
Norcraft DSC Site Bank Addition	Capacity Enhancement	50%	MCS	0.501	1.950	0.610								Approved Outlook	3.061
St. Laurent Station New Feeder	Capacity Enhancement	50%	MCS		2.230										2.230
Whiteshell 33 kV System Improvements	Capacity Enhancement	50%	MCS	0.320	3.100	0.100								Approved Outlook	3.520
Winnipeg Area 66kV Line Upgrades	Capacity Enhancement	50%	MCS	1.160	0.455	0.060	0.150	0.095						Approved Outlook	1.920
HSC Service Consolidation & Dist Upgrade		42%	MCS	5.187										Approved Outlook	5.187
New Madison Station - 115-24kV Station		17%	MCS	42.282	9.745									Approved Outlook	52.027
Adelaide: King Station 12kV Salvage		0%	MCS							2.014					2.014
Anola DSC		0%	MCS	2.680										Approved Outlook	2.680
Harrow Station - Bank & Feeder Addition		0%	MCS	0.177	1.104	3.567	9.023	10.656						Approved Outlook	24.527
Mohawk Station - Bank & Feeder Addition		0%	MCS	1.165	5.349	10.465	1.865							Approved Outlook	18.844
Mystery Lake Station Switchgear Replace & Bank Add		0%	MCS	1.245										Approved Outlook	1.245
New Adelaide Station - 66/12kV		0%	MCS	22.509	27.261	6.934	3.418	0.722						Approved Outlook	60.844
New Dawson Road Station - 115kV to 24kV		0%	MCS	0.205	4.248	17.750	20.000	9.578						Approved Outlook	51.781

Projects	Justification	% Capacity Related	Owning B.U.	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	Source	Total
New McPhillips Station - 115kV to 24kV		0%	MCS	2.586	18.759	18.848	6.768							Approved Outlook	46.961
New St. Vital Station		0%	MCS	3.684	25.146	22.200								Approved Outlook	51.030
Property Acquisition - New Downtown Station Site		0%	MCS	0.231										Approved Outlook	0.231
PTH#59/101 Interchange Build		0%	MCS	0.250	2.000										2.25
Relocation L17 Semple Stn to Kingsbury		0%	MCS	0.470										Approved Outlook	0.470
Rover 4kV Station Salvage & Feeder Conv.		0%	MCS	0.050	3.800	3.562								Approved Outlook	7.412
Planning Item (Distribution Modernization)		0%	MCS	9.000	15.000	7.400	9.800	12.800	31.600	21.500	19.900	17.400	17.400		161.800
Planning Item (Wpg area Projects)	Capacity Enhancement	60%	MCS	0.075	2.195	4.865	11.355	40.475	60.135	50.710	76.930	86.720	54.115		387.575

REFERENCE:

Figure 8.14 in Tab 8, page 31 and Response to GAC/MH I-41

PREAMBLE TO IR (IF ANY):

The response to GAC/MH I-41 provides the loss factor applied to marginal cost for distribution level customers only.

QUESTION:

Please provide the demand and energy loss factors that would be applied to derive marginal generation cost and T&D marginal capacity cost for the other customer classes indicated in Figure 8.14.

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro uses transmission losses estimates of 10% and distribution losses of 4% for the purpose of marginal cost evaluations. Manitoba Hydro has not prepared any estimates of marginal losses by customer class.

REFERENCE:

Figure 8.14 in Tab 8, page 31 and response to GAC/MH I-41

PREAMBLE TO IR (IF ANY):

The response to GAC/MH I-41 addresses only the loss factor applied to the generation component of marginal cost.

QUESTION:

Please provide the following information:

a) Indicate whether the marginal generation cost component in Figure 8.14 of 6.34 cents per kW.h includes the 14% loss factor that applies to load at the distribution level

RATIONALE FOR QUESTION:

RESPONSE:

The marginal generation cost component in Figure 8.14 of 6.34 cents per kWh does include the 14% loss factor that applies to load at the distribution level.

REFERENCE:

Figure 8.14 in Tab 8, page 31 and response to GAC/MH I-41

PREAMBLE TO IR (IF ANY):

The response to GAC/MH I-41 addresses only the loss factor applied to the generation component of marginal cost.

QUESTION:

Please provide the following information:

b) Indicate whether the estimates of marginal transmission and distribution capacity cost in Figure 8.14 incorporate losses.
   i) If so, specify the loss factors included and provide the basis of the loss factors.

RATIONALE FOR QUESTION:

RESPONSE:

The marginal transmission and distribution cost components of 0.57 and 0.78 cents per kWh in the Figure 8.14 of Tab 8 (REVISED) do include the 14% loss factor that applies to load at the distribution level, as discussed in Manitoba Hydro's response to GAC/MH II-23.

While class specific marginal loss estimates are not available, the generation and transmission marginal cost components used for the GSL 30-100 kV and GSL >100 kV class have been updated below to include only the 10% loss factor applicable to load at the transmission level.

	Levelized Marginal Value (¢/kWh)			
	Gen	Trans	Dist	Total
Residential	*4.39*	*0.57*	*0.78*	*5.75*
GSS ND	*4.39*	*0.57*	*0.78*	*5.75*
GSS D	*4.39*	*0.57*	*0.78*	*5.75*
GSM	*4.39*	*0.57*	*0.78*	*5.75*
GSL 0-30	*4.39*	*0.57*	*0.78*	*5.75*
GSL 30-100	***4.23***	***0.55***		***4.77***
GSL >100	***4.23***	***0.55***		***4.77***

REFERENCE:

Figure 8.14 in Tab 8, page 31 and response to GAC/MH I-41

PREAMBLE TO IR (IF ANY):

The response to GAC/MH I-41 addresses only the loss factor applied to the generation component of marginal cost.

QUESTION:

Please provide the following information:

b) Indicate whether the estimates of marginal transmission and distribution capacity cost in Figure 8.14 incorporate losses.
   i) If so, specify the loss factors included and provide the basis of the loss factors.

RATIONALE FOR QUESTION:

RESPONSE:

The marginal transmission and distribution cost components of 0.56 and 0.87 cents per kWh in Figure 8.14 of Tab 8 do include the 14% loss factor that applies to load at the distribution level, as discussed in Manitoba Hydro's response to GAC/MH II-23.

While class specific marginal loss estimates are not available, the generation and transmission marginal cost components used for the GSL 30-100 kV and GSL >100 kV class have been updated below to include only the 10% loss factor applicable to load at the transmission level.

	Levelized Marginal Value (¢/kWh)			
	Gen	Trans	Dist	Total
Residential	6.34	0.56	0.87	7.77
GSS ND	6.34	0.56	0.87	7.77
GSS D	6.34	0.56	0.87	7.77
GSM	6.34	0.56	0.87	7.77
GSL 0-30	6.34	0.56	0.87	7.77
GSL 30-100	**6.10**	**0.54**		**6.64**
GSL >100	**6.10**	**0.54**		**6.64**

REFERENCE:

Appendix 9.14

PREAMBLE TO IR (IF ANY):

QUESTION:

Please document the calculation of the illustrative rates in Figure 7, including all workpapers and electronic spreadsheets.

RATIONALE FOR QUESTION:

RESPONSE:

The revenue derived from the illustrative rates shown in Figure 7 were designed to be revenue neutral to the revenue derived from the proposed April 1, 2018 rates filed in Appendix 9.4 (Updated) and as shown in the Proof of Revenue filed in Appendix 9.2 (Updated).

The monthly Basic Charge for the Illustrative Rates was set to be equal to the proposed April 1, 2018 rates, and only the energy charge was adjusted. With the proposed April 1, 2018 energy charge set at $0.08843 per kWh, the illustrative energy rates were set at an amount higher than this for Basic Standard and an amount lower than this for Basic All-electric, until the point that revenue neutrality was achieved, as shown in the table below. Manitoba Hydro constrained the increase to the Basic Standard energy charge such that the overall bill impacts would be less than 10% when compared to current August 1, 2017 rates.

	Revenue at Proposed April 1, 2018 Rates	Revenue at Illustrative Rates	Difference
Basic Std	$311,434,897	$316,633,296	$5,198,399
Basic AE	$419,745,623	$414,560,867	($5,184,756)
Total	$731,180,520	$731,194,162	$ 13,642*

*Difference due to rounding the energy rate for billing system purposes.

The Excel Attachment containing the billing determinants used to derive the revenues associated with both the proposed rates and illustrative rates has separately been provided to the PUB and Registered Interveners.

REFERENCE:

Appendix 9.14

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the workpapers and Excel spreadsheets (with formulas intact) used to derive the Illustrative Proof of Revenue in Figure 8.

RATIONALE FOR QUESTION:

RESPONSE:

Please refer to the Excel spreadsheet provided in response to GAC/MH II-25.

REFERENCE:

Appendix 9.14, Page 18

PREAMBLE TO IR (IF ANY):

Manitoba Hydro expresses concern that multiple billing cycles would complicate the implementation of a four period seasonal rate in such a way that "would likely result in significant customer confusion and potentially an increase in calls to Manitoba Hydro's contact center with these changes to customer bills."

QUESTION:

Please explain whether Manitoba hydro's concern about customer confusion would be resolved if:

a) The rate design had two periods only – summer and winter periods of 6 months each, and

b) The rate discount were based on the date of the meter read, so that, for example, any bill based on a meter read in a winter month would get a discount for the entire usage on that bill.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro's concern could be mitigated by having two periods instead of four However, the same potential for confusion would exist; it would just exist less often.

b) Manitoba Hydro would continue to have significant concern under the second proposal. Meters are read approximately once every 60 days, if conditions allow. Having a potential 60 day difference between the start and end of the discount period could result in significantly variable customer impacts determined by something as arbitrary as the customer's meter read date. Furthermore, since Manitoba Hydro sometimes has difficulty accessing or obtaining either an actual read, applying the rate discount based on the date of the meter reading could easily result in an extended "winter discount" period.

REFERENCE:

Appendix 9.14, section 8.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain Manitoba Hydro's rationale(s) for the proposed alternative rate design in relation to past PUB concerns or other concerns, such as:

   i. Mitigating the disproportionate impact on electric space heat customers that could arise from the introduction of inclined rates if they had the same first block. [e.g. Board Order 5/12, p. 220]

   ii. Mitigating the impact of protracted steep rate increases on lower income ratepayers and in particular those who are all-electric customers. [e.g. Board Order 73/15, p. 27]

   iii. Any other rationale from the PUB, other stakeholders, or Manitoba Hydro.

b) Please indicate if and how the proposal is intended to be responsive to the evaluative criteria developed by the Bill Affordability Working Group [Appendix 10.5, p. 31/242] including in particular criterion d:

   d. **Equity:** The programs must treat equals equally and "unequals" proportionately (in other words, program recipients with higher need should receive proportionately more benefit; defining equality usually rests on an income test).

   If the Bill Affordability Working Group criteria were not part of the rationale, please explain why not?

RATIONALE FOR QUESTION:

RESPONSE:

a) The illustrative rate design found in Appendix 9.14 at section 8 is provided for discussion purposes only as it has not been endorsed by the Manitoba Hydro-Electric Board. As such, Manitoba Hydro is not seeking approval of this alternative scenario.

The separation of residential customers into Residential Basic All Electric (Electric Heat Billed) and Residential Standard Basic (Non Heat Billed) sub-classes provides information as to the cost of serving electric space heat customers versus non space heating customers, as shown in the response to PUB/MH II–93. Potential rate structure options can then be evaluated against the residential customer sub-classes to obtain a better understanding of the impacts on electric heat customers, which was a concern noted by the PUB in past Orders.

In terms of the impact on lower income customers who are reliant on electricity for home heating purposes, it is noted that household income and household energy consumption are not necessarily related, as there are lower income residences that have above average annual electricity consumption. Therefore, the illustrative rate structure shown in Appendix 9.14 would serve to shield higher usage low income customers from a portion of the proposed rate increase.

b) Manitoba Hydro would like to clarify that the evaluative criteria determined by the Bill Affordability Working Group were developed specifically to evaluate a number of bill assistance options and bill subsidy programs. While some may appear to be similar to Manitoba Hydro's General Rate Making Objectives, they may not be directly applicable to rate setting. Manitoba Hydro has a long standing set of General Rate Making Objectives (found at page 2 of Tab 9 of this Application) that have been included in General Rate Applications before the PUB for many years, which form the basis for its decisions regarding the appropriate rate structure for the sale of electricity.

REFERENCE:

Appendix 9.14, section 8.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please indicate if the revenue shift from all-electric to standard customers is intended to be
   i. a one-time shift in 2018-2019 to establish a new baseline for future increases without further mitigation or
   ii. a repeated differential increase over multiple years
   (1) until above-inflationary rate increases are ended, or
   (2) some other period (please specify).

b) Please calculate
   i. the aggregate cumulative costs of foregone revenues to the utility from electric heat customers under Hydro's indicative rate increases that would have to be made up by other customers under each of the above scenarios,
   ii. the per household cumulative costs to the utility and other customers for representative electrically heated single family dwellings with relatively low, medium and high electric bills, and
   iii. the subsidized and unsubsidized annual and cumulative electric bills and net savings with the subsidy to the participating customer going forward under scenario a) ii) (1) above

c) Please estimate
   i. the installation costs of (i) geothermal systems and (ii) solar arrays (with and without currently available subsidies) sufficient to cover the annual heating load for each of the above representative single family dwellings, and
   ii. annual bills and annual bill savings under unsubsidized rates for each of the above installations for each representative single family dwelling.

iii. Please identify current subsidies, credits, and rebates from Hydro, the Province or other sources, with expiry dates and other relevant details that are currently available to customers who install geothermal systems and solar arrays.

d) Please determine for each of the above installation scenarios (geothermal or solar for each representative all-electric single family dwelling)
   i. the time period for full payback of the technology installation costs for each scenario under PAYS financing, and
   ii. annual bills for the customer, under each scenario, with and without the PAYS financing in comparison with the bills in b) iii) above.

RATIONALE FOR QUESTION:

RESPONSE:

a) The illustrative rate design found in Appendix 9.14 at section 8 is provided for discussion purposes only as it has not been endorsed by the Manitoba Hydro-Electric Board. As such, Manitoba Hydro is not seeking approval of this alternative scenario.

   The illustrative residential rate design scenario was provided for discussion purposes to illustrate an alternative method that may be employed in rate design for the residential class. In the event that Manitoba Hydro sought approval of an alternative residential customer class structure that included different rates for Residential Basic Standard and Residential Basic All Electric sub-classes, the further application of proposed rate increases would be evaluated in the course of future General Rate Applications, depending upon the circumstances at that time.

b) With regard to the illustrative rate design in the scenario provided, there was a shifting of revenue collection from Residential Basic All Electric customers to Residential Standard Basic customers of approximately $5.2 million as shown in Figure 6 on page 13 of Appendix 9.14.

   The overall revenue increase to the Residential class in total is 7.9%, and the rates for Residential Basic All Electric and Residential Basic Standard sub-classes that were determined in this illustrative scenario would represent revenue increases of 6.56% for Basic All Electric and 9.7% for Basic Standard customers respectively. This is shown in the Illustrative Proof of Revenues in Figure 8 on page 14 of Appendix 9.14.

The respective illustrative bill impacts are shown in Figure 9 on page 15 of Appendix 9.14.

c)

i. The following table presents the estimated installation costs for a geothermal system and a solar PV system sufficient to cover the annual heating load for an electrically heated home consuming 1000 kWh/month, 2000 kWh/month and 5000 kWh/month as presented in Figure 9 on page 15 of Appendix 9.14. The installation cost is presented with and without incentives currently available from Manitoba Hydro.

Average Monthly Energy Use	Geothermal		Solar PV	
	Cost	With PS Incentive	Cost	With PS Incentive
1000 kWh/month	$ 18,124	$ 18,124	$ 17,611	$ 11,611
2000 kWh/month	$ 18,881	$ 18,881	$ 29,092	$ 19,092
5000 kWh/month	$ 31,041	$ 31,041	$ 72,749	$ 46,749

Assumptions:

1. Annual heating load is assumed to be 55 percent of annual electricity consumption.
2. Costs have been estimated by using participation data from the Earth Power Loan (geothermal installs) and the Solar Energy Program.
3. Manitoba Hydro does not offer a residential geothermal heat pump incentive program.

ii. The following table presents the estimated annual electricity bills and estimated annual bill savings under Manitoba Hydro's residential electricity rates proposed for April 1, 2018 as found at Appendix 9.4 Updated., if the above electrically heated homes noted in c) part (i) installed a geothermal system or a solar PV system.

Average Monthly	Geothermal		Solar PV	
Energy Use	Annual Bill	Annual Bill Savings	Annual Bill	Annual Bill Savings
1000 kWh/month	$ 815.62	$ 350.18	$ 467.03	$ 698.77
2000 kWh/month	$ 1,526.59	$ 700.37	$ 1,062.34	$ 1,164.62
5000 kWh/month	$ 3,659.53	$ 1,750.91	$ 2,382.42	$ 3,028.02

Assumptions:

1. Geothermal calculated assuming a 2.5 coefficient of performance.
2. Proposed residential rates for April 1, 2018 as per Appendix 9.4 Updated and 9.5 Updated.

iii. With regard to current subsidies, credits and rebates for geothermal heat pump systems and solar arrays, the following table outlines Manitoba Hydro's current offerings and Manitoba Hydro's knowledge of what the Province of Manitoba currently offers:

GEOTHERMAL HEAT PUMP SYSTEMS					
Source	**Program Name**	**Program Type**	**Customer Type**	**Offer**	**Program End Date**
Manitoba Hydro	Residential Earth Power Loan	Financing	Residential	- borrow up to $20,000 - maximum term = 15 years - 4.9% annual interest rate - monthly installments included on energy bill - loan is non-transferable	TBD
	Pay As You Save Financing (PAYS)	Financing	Residential	- maximum financing depends on estimated utility savings - maximum term = 20 years - 3.9% annual interest rate - monthly installments included on energy bill - loan is transferable	TBD
	Community Geothermal Program	Community Based Rebate & Financing	First Nation Residential	- community based initiative for geothermal installation in residential homes on First Nations - average community based rebate = $4,900 - financing provided thorough PAYS - local band members trained to install GSHP	TBD
	Commercial Geothermal Program - system installation incentive	Rebate	Commercial	System installation incentive calculated as being the lesser of: 1) $2.50 per sq. ft. heated by GSHP; OR 2) $120 per MBH of installed geothermal heating capacity; OR 3) $120 per MBH of buildings eligible base transmission and infiltration heating load	TBD
	Commercial Geothermal Program - feasbility study assistance	Rebate	Commercial	Assistance up to 50 per cent of the first $5,000 and up to 25 percent of the remaining cost of the study (to a max. grant of $10,000 per study)	TBD
Province of Manitoba	Provincial Grants	Rebate	Residential	- $2,600 grant for homes in natural gas service areas	None listed
			District/Community GSHP Systems	- maximum grant of $150,000 available to GSHP systems that serve several buidings	None listed
	Green Equipment Tax Credit	Tax Credit	Residential, Commercial & District/Community	- refundable tax credit up to 15 per cent	None listed
SOLAR PHOTOVOLTAIC SYSTEMS					
Source	**Program Name**	**Program Type**	**Customer Type**	**Offer**	**Program End Date**
Manitoba Hydro	Residential Earth Power Loan	Financing	Residential	- borrow $3,000 per kW installed (DC rated) up to a maximum of $30,000 - maximum term = 15 years - 4.9% annual interest rate - monthly installments included on energy bill - loan is non-transferable	TBD
	Solar Energy Program (2-year pilot)	Rebate	Residential, Commercial, Industrial	- incentives available to assist with upfront capital cost of the system - incentive is limited by the average annual electricity consumption (kWh) at customers site & amount of PV required to offset annual electricity bill - $1 per watt installed (DC rated) rebate - minimum 1 kW system size; maximum 200 kW	April 2018

d) Under Residential PAYS Financing, which is governed by the *Energy Savings Act*, financing is limited to where the average monthly bill savings are greater than the monthly financing charge (loan plus interest).

A simple payback period has been calculated for if each of the above electrically heated homes noted in c) part (i) installed a geothermal system or a solar PV system. The annual average monthly energy savings are not sufficient in most scenarios to cover the PAYS monthly charge (loan plus interest) within the technology's useful life and therefore the full cost of geothermal and solar PV would not be eligible to be financed under Residential PAYS for all but the largest single family dwellings. If the financing was to be offered, the average monthly energy bill with financing would be higher than the average monthly energy bill pre-installation of the geothermal or solar PV systems.

	Geothermal		Solar PV	
Average Monthly Electricity Use	Simple Payback	Annual Bill (no PAYS)	Simple Payback	Annual Bill (no PAYS)
1000 kWh/month	52	$ 815.62	25	$ 467.03
2000 kWh/month	27	$ 1,526.59	25	$ 1,062.34
5000 kWh/month	18	$ 3,659.53	24	$ 2,382.42