Exhibit PUB #

Volume 4 – Board Counsel's Book of Documents

Manitoba Hydro 2012/13 and 2013/14 GRA

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PROOF OF REVENUE

Interim Approved September 1, 2012 Rates versus Proposed April 1, 2013 Rates
for year ended March 31, 2014

	Calculated Revenue 2012 Rates	Calculated Revenue 2013 Rates	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic	546,005,529	565,178,116	19,172,588	3.5%
Diesel	598,001	618,856	20,856	3.5%
Seasonal	7,522,059	7,739,786	217,727	2.9%
FRWH	1,137,702	1,177,411	39,709	3.5%
Total Residential	**$555,263,291**	**$574,714,170**	**$19,450,879**	**3.5%**
Small Non-Demand	130,588,658	135,203,094	4,614,437	3.5%
Small Demand	132,049,062	136,623,616	4,574,553	3.5%
Seasonal	541,375	560,523	19,148	3.5%
FRWH	496,570	513,956	17,386	3.5%
Total Small	263,675,665	272,901,190	9,225,524	3.5%
Total Medium	183,034,939	189,465,805	6,430,867	3.5%
Large 750 V-30 kV	89,239,183	93,361,733	3,122,550	3.5%
Large 30 - 100 kV	51,122,166	52,915,714	1,793,548	3.5%
Large > 100 kV	193,151,023	199,914,479	6,763,456	3.5%
Total Large	333,512,372	345,191,926	11,679,554	3.5%
Diesel GS & Gov.	5,879,313	5,884,006	4,693	0.1%
SEP	0	0	0	0.0%
Total GS	**$786,102,289**	**$813,442,927**	**$27,340,638**	**3.5%**
Area & Roadway	**$21,537,415**	**$22,289,337**	**$751,922**	**3.5%**
DSM Reduction	(18,824,793)	(19,485,582)	(660,789)	3.5%
Misc. Rev & Adjs.	7,670,747	7,938,973	268,226	3.5%
General Consumers	**$1,351,748,947**	**$1,398,899,824**	**$47,150,877**	**3.5%**

CAC-GAC/MH I-4

Subject: **Avoided Costs**
Reference: **2011 Power Smart Plan, Chapter 2**

Preamble: **The value of DSM depends primarily on utility avoided costs. Most utilities base their avoided costs on the long-run cost of new generation and associated T&D costs, and provide both the values and the underlying assumptions as part of the rate hearing.**

b) If Manitoba Hydro uses separate values for capacity and energy, please provide them as well as a blended average for each major sector/end use.

ANSWER:

Average marginal costs for each major sector/end use are provided as blended average marginal cost values, as follows:

a) At the generation level, the blended average marginal cost is 6.2 ¢/kW.h.
b) At the transmission level, the blended average marginal cost is 7.5 ¢/kW.h.
c) At the distribution level, the blended average marginal cost is 8.5 ¢/kW.h.

Manitoba Hydro does use separate values for capacity and energy but respectfully declines to provide this break-down as this information is commercially sensitive.

All values provided were levelized over the next 30 years. The marginal costs provided herein are consistent with the values used in the 2011 Power Smart Plan.

GAC/MH II-23

Subject: **DSM Avoided Costs**
Reference: **MH response to CAC-GAC/MH I-4(a)**

Regarding the marginal cost estimates provided in response to CAC-GAC/MH I-4(a), please provide the following information:

c) the estimate of marginal transmission costs per kW/yr restated as costs per kW.h

i. Include all workpapers and Excel spreadsheets (with formulas intact) supporting this restatement of marginal transmission cost.

ANSWER:

The current estimates of Transmission and Distribution marginal costs provided in CAC-GAC/MH I-4(a) were transcribed in error. The appropriate values in 2011 dollars are as follows:

- Transmission: $60.46/kW/yr
- Distribution: $63.83/kW/yr

The marginal transmission costs expressed as $60.46 per kW/yr are restated as 0.69 cents per kWh when averaged over the 8766 hours in a planning year.

GAC/MH II-23

Subject: **DSM Avoided Costs**
Reference: **MH response to CAC-GAC/MH I-4(a)**

Regarding the marginal cost estimates provided in response to CAC-GAC/MH I-4(a), please provide the following information:

d) the estimate of marginal distribution costs per kW/yr restated as costs per kW.h

i. Include all workpapers and Excel spreadsheets (with formulas intact) supporting this restatement of marginal distribution cost.

ANSWER:

The current estimates of Transmission and Distribution marginal costs provided in CAC-GAC/MH I-4(a) were transcribed in error. The appropriate values in 2011 dollars are as follows:

- Transmission: $60.46/kW/yr
- Distribution: $63.83/kW/yr

The marginal distribution costs expressed as $63.83 per kW/yr are restated as 0.73 cents per kWh when averaged over the 8766 hours in a planning year.

CAC/MH II-27

Subject: **Proposed Rates and Customer Charges**
Reference: **CAC/MH I-83 a)**
PUB/MH I-107 a)
CAC-GAC/MH I-4 a) and b)

b) Please provide a breakdown of the 8.52 cents/kWh by cost component (e.g. generation, transmission and/or distribution) in cents/kWh at the distribution level. Please explain how losses are reflected in the value of each cost component.

ANSWER:

The current estimates of Transmission and Distribution marginal costs provided in CAC/GAC/MH I-4(a) were transcribed in error. The appropriate values in 2011 dollars are as follows:

- Transmission: $60.46/kW/yr
- Distribution: $63.83/kW/yr

The marginal cost of 8.52 cents per kWh referenced above is at the distribution level and includes all generation costs and all capital costs associated with transmission and distribution. This value is made up of the following components:

Generation	7.11¢/kWh
Transmission	0.69¢/kWh
Distribution	0.73¢/kWh

The generation component cost is derived at the generation level and a 14% adjustment has been incorporated to arrive at the 7.11¢/kWh estimate that is applicable to load savings at the distribution level. There are no further loss factors applied to the transmission component or the distribution component at the distribution level.

1 that -- report that talks about -- or discusses,
2 anyways -- how the marginal values are calculated for
3 that.
4 MR. BOB PETERS: Ju -- just let me jump
5 in on that comment.
6 MR. TERRY MILES: Okay.
7 MR. BOB PETERS: I -- I believe Mr.
8 Chernick had some criticism of -- of the marginal cost
9 of transmission and distribution.
10 And I had understood, I think from the
11 Manitoba Hydro rebuttal evidence, that Manitoba Hydro
12 was reviewing the 2004 methodology for -- for possible
13 changes?
14 MR. TERRY MILES: We are reviewing it
15 for some possible changes, yes. And that process is --
16 is ongoing. We're in the process of putting together
17 that report or updating that report.
18 Our intention is if that -- or when that
19 report becomes available, because it will -- will
20 become available, we will file that with these
21 proceedings, whether it's during the hearings or
22 whatever. We will file that updated report for --
23 MR. BOB PETERS: And that's expected
24 when?
25 MR. TERRY MILES: I can't say exactly

when it is expected. I will say sooner than later. I will say it is in draft form. It has to go through the -- it does have to go through the formal approval processes with Manitoba Hydro, but --

MR. BOB PETERS: Will it be provided before the next Power Smart Program, just in terms of timeline?

(BRIEF PAUSE)

MR. TERRY MILES: I would -- I would expect that, yes.

MR. BOB PETERS: And just while we're on the transmission and distribution marginal costs, those do not include line losses as -- as an example, correct?

(BRIEF PAUSE)

MR. TERRY MILES: In the -- in the numbers shown in this -- in this IR that's here, the losses are at the generation level right here. We do -- there is another IR that we do indicate the marginal values at the generation, transmission, and distribution levels, with the losses incorporated at

1 those levels. I was just going to -- I was just going
2 to see if I could find that quickly here. It is right
3 here.
4
5 (BRIEF PAUSE)
6
7 MR. BOB PETERS: I appreciate, Mr.
8 Miles, that when the microphones are live, it's
9 difficult to -- to locate everything that your -- your
10 mind tells you that you have at hand. I know it well.
11 The -- the point, you're -- you did find
12 it?
13 MR. TERRY MILES: I -- I did find it,
14 yeah. It's actually CAC -- CAC/GAC/MH Round 1 4B. And
15 it gives the net generation cost, the transmission
16 level cost, and the distribution level cost, which
17 would include losses at each of those levels.
18 And just as a note, the generation level
19 is six point two (6.2) cents per kilowatt hour; the
20 transmission level at seven point five (7.5) cents per
21 kilowatt hour; and at the distribution level, it's
22 eight point five (8.5) cents per kilowatt hour.
23 MR. BOB PETERS: It comes to the same
24 number?
25 MR. TERRY MILES: In the end at the

1 distribution level, yes, because that's what the -- so
2 the -- the long-run marginal value incor -- is -- is
3 all of the -- all of the components with the losses
4 associated with it, yes.
5 MR. BOB PETERS: And Mr. Chernick was
6 suggesting that the -- with the addition of the line
7 losses and other adjustments, that those marginal costs
8 would be higher.
9 And -- and you don't come to the same
10 conclusion?
11 MR. TERRY MILES: I think what we've
12 responded to before, to Mr. Chernick's comments on
13 those in -- in previous hearings was that the values
14 that we -- that are represented here represent average
15 system losses overall and not specific components of
16 such. So their average system losses, their average
17 costs associated with them.
18 So in light of that, given those -- how
19 we determine the losses or how they're assessed and how
20 they're used, that these values are representative of
21 the losses at those levels. I think under -- there are
22 -- I think your reference of cost of service report
23 that's there -- and I'm not intimately familiar with
24 the losses that are associated in there, but I do
25 understand that we do use slightly different losses at

1 the different load levels or customer levels that are a
2 little different than these overall average system
3 losses that we have quoted here for these numbers.
4 MR. BOB PETERS: From a conceptual
5 level, Manitoba Hydro would agree that unless you
6 included the line losses, you would be understating
7 your marginal value?
8 MR. TERRY MILES: I believe the line
9 losses need to be included in those calculations, yes.
10 MR. BOB PETERS: Now, we were talking
11 about the specific calculation for the Board, and we
12 segued on to the transmission and distribution
13 discussion.
14 But I wasn't looking for confidential
15 information, but in terms of methodology at least, in
16 terms of how Manitoba Hydro derived the various
17 calculations that you spoke with the Board about?
18 MR. TERRY MILES: So from the T&D
19 perspective, I'm -- I'm assuming that the 2004 report
20 methodology with an update of the -- if a -- an updated
21 report is provided, that would be sufficient for those
22 -- for those?
23 MR. BOB PETERS: Yes, for the
24 transmission/distribution. And then what would you
25 propose for the generation?

- In Ontario Energy Board EB-2010-0008, in which Mr. Chernick represented the Green Energy Coalition, the School Energy Coalition (SEC) included in its non-confidential discovery requests a couple of actual values for confidential Ontario Power Authority estimates of the costs of returning mothballed nuclear plants to service. Those requests were intended to be in a separate confidential list of confidential requests. The questions were recalled by the Board and the SEC within a few hours of the infraction, the Board required all parties to document destruction of the offending documents (although most of those parties had access to the original estimates and other confidential materials) and the SEC's attorney was fined $10,000. The Board order in that matter, which discusses one other disclosure, is attached as Attachment PUB/GAC-2.

- In Massachusetts DPU 10-54, in which Mr. Chernick represented Natural Resources Defense Council and Conservation Law Foundation, the Alliance to Protect Nantucket Sound (an ad hoc group formed for the sole purpose of opposing the Cape Wind offshore wind farm, and with no other prospect of appearing before the DPU) allegedly released some confidential Cape Wind cost estimates to the press. While Mr. Chernick was not directly involved in the sanctioning of the Alliance, it is his recollection that the Alliance was barred from any further access to confidential information, including testimony, discovery and exhibits.

PUB/GAC 2 Reference: Page 12 & 13

Please comment on the use of a levelized cost of 7.11 ¢/kWh in defining marginal cost of generation and explain how that relates to the export value of energy.

Response:

Mr. Chernick's ability to comment on this value is limited by Hydro's refusal to provide the derivation of the value (GAC/MH II-25a, II-25d). In addition, it is not clear whether and how Hydro uses the 7.11¢/kWh value, as opposed to values reflecting time of use and class-specific losses.

PUB/GAC 3 Reference: Page 16 &17, Footnote 3.

a) Please indicate the source of MH's 6.2 ¢/kWh marginal cost of generation.

b) Discuss how this relates to the in-service cost of new generation and transmission for:

- Wuskwatim
- Keeyask
- Conawapa

c) Please indicate whether incremental Bipole III related additional costs are reflected in Table 2. Please provide details.

d) Please provide supporting calculations for the avoided costs referenced in footnote 3.

Response:

a) Hydro's 7.11 ¢/kWh marginal cost of generation includes the average T&D system energy losses of 14%. Mr. Chernick derived the 6.2 ¢/kWh marginal cost *at the generation level* by removing the 14% loss factor: 7.11¢/kWh ÷ 1.14 = 6.2¢/kWh. (GAC/MH II-4a, CAC-GAC/MH I-4b).

b) Mr. Chernick cannot provide these comparisons, because Hydro has refused to provide the derivation of the marginal cost and the costs of new projects (GAC/MH II-25a, GAC/MH I-2e).

c) See (b).

d) 0.69¢/kWh ÷ 0.62 = 1.11¢/kWh and 0.73¢/kWh ÷ 0.62 = 1.18¢/kWh, where 0.62 is the average MH system load factor.

PUB/GAC 4 Reference: Page 16, Marginal Costs

Please indicate the implications of applying your estimate of marginal costs on screening of DSM programs versus the marginal cost value employed by MH.

Response:

Mr. Chernick did not derive an independent estimate of marginal cost. Instead, for rate-design comparison purposes, he modified the marginal cost values (excluding losses) that MH developed for screening DSM. He adjusted for the following: (1) the effect of the customers' voltage levels of service on peak and energy loss factors, (2) the effect of the rate class customers' voltage level of service on the use of distribution system, and (3) a typical retail load factor. These marginal cost values by rate class should not be used in screening DSM, for two reasons: (1) they include only costs to the meter, while avoided costs for DSM should include costs to the end use (as explained in footnote 8 on page 17); and (2) the avoided costs for DSM should reflect the load shape of the end use or measure being screened.

Since MH has not documented its use of marginal cost in screening DSM, Mr. Chernick cannot evaluate how any change in marginal cost would affect MH's screening results.

PUB/GAC 5 Reference: Page 17, Marginal Cost by Rate Schedule, Footnote 8

a) Please explain and discuss how the marginal cost by Rate Class would change if based on a typical retail load shape.

b) Please provide Mr. Chernick's understanding of MH's retail load shape.

c) Please provide an example of how end use losses are derived.

d) Please explain how the system wide avoided costs related to losses to the end use would be measured.

e) To what extent is avoided costs and losses to the end use measured in other jurisdictions?

Response:

a) For the effect on T&D marginal cost, see page 12, footnote 3 of Mr. Chernick's testimony and GAC's response to PUB/GAC 3(d). Since Hydro did not provide its derivation of marginal generation costs, it is not possible to estimate how the marginal cost by rate class would change if based on a typical retail load shape.

b) See Hydro Appendix 8.1, Tables 22, 24, 27 and 28 for data on monthly energy and peak load, including forecasts. Hourly load for the demand-metered classes is provided in GAC-MH I-8F-Attachment. Mr. Chernick is not aware of any hourly load data in the current record. Some data on peak, shoulder and off-peak load are available from Appendix 38, Attachment 4 in the previous GRA, attached as Attachment PUB/GAC-5.

c) In principal, losses to the end use could be computed from estimates of the length and nature of the internal wiring from the meter to the end use and the distribution of loads within the building. Practically speaking, the easiest customer-side losses to estimate are those for customers metered at primary or transmission voltage, who generally have transformers and internal distribution on the customer side of the meter similar to the utility distribution system for customers served at secondary. Hence, it is reasonable to assume that losses to the end use for all classes are comparable to the utility's losses to the meter for customers served at secondary. This assumption would understate total line losses, by excluding losses from the secondary meter (or equivalent) to the end use.

d) See (c).

e) Mr. Chernick has not conducted a recent survey.

PUB/GAC 6 Reference: Page 18, Cap & Trade Internalized Costs

a) Please describe the cap & trade system for pollutants that is in place in the MISO region.

b) In particular, please describe how this cap and trade system pertains to Minnesota and Wisconsin and explain how this results in an internalized cost.

1 Minnesota, and Vermont?

2 MS. LOIS MORRISON: Well, as I

3 mentioned in my direct testimony, we support the

4 concept of comparing to metrics; however, it has to be

5 done with caution and in consideration of all the --

6 the differences between the two (2) markets or between

7 the markets.

8 As I mentioned, Vermont, Nova Scotia,

9 and British Columbia, all have significantly higher

10 marginal values associated with the energy savings,

11 which means that technologies that would be economic

12 there may not be economic in Manitoba. The other issue

13 that we had talked about was the presence of -- and Mr.

14 Dunsky did attempt to -- to look at it from the

15 perspective of the heating degree days, but what was

16 not considered was the percentage of electric heat

17 associated with that.

18 And when you have that in the metric,

19 what it does is it drives up the size of your

20 denominator. So, when you're doing the math, we're

21 starting out with a much larger denominator just

22 because of the fact that we have higher degree heating

23 -- degree days heating and a higher percentage of

24 electric heat. And -- and there has been discussion

25 that -- well then that means you have more

c) Please explain how those internalized costs are directly applicable to MH's domestic consumption of electricity.

Response:

a) There is no cap & trade system for greenhouse gases in place in the MISO region. The cap & trade system for SO_2 that was instituted in the 1990 Clean Air Act Amendments is effectively defunct, since scrubbing and other controls required under other programs have created a surplus of allowances. While SO_2 allowances once traded in the hundreds of dollars per ton, they are now priced under $1/ton. Allowances for NOx emissions under the Clean Air Interstate Rule (CAIR) are trading in the $25–$50/ton range. Allowances for both SO_2 and NOx under the Cross-State Air Pollution Rule (CSAPR, which would have replaced CAIR) traded in the range of several hundred dollars per ton in late 2011, but have plunged to essentially no value since a Federal court vacated the rule.

b) Depending on when a particular contract was or will be negotiated, it may reflect some expectation that CSAPR would be in place (perhaps reinstated or redesigned, depending on the outcome of the EPA's appeal) and/or that some greenhouse-gas cap or tax will be enacted. It is not clear that the environmental value of reduced emissions resulting from Hydro's sales are fully included in any current or pending contract price.

c) Electric energy not used in Manitoba will, for the most part, be sold to Minnesota and Wisconsin, or to a lesser extent Saskatchewan or Ontario, backing down primarily coal and gas-fired plants and reducing emissions of greenhouse gases and conventional pollutants. To the extent that those environmental effects are not included in the contract prices, they are not internalized and must be added to the benefits of energy efficiency and the costs of energy consumption (which prevents the beneficial exports).

PUB/GAC 7 Reference: Page 18 , Total Societal Cost

a) Please provide Mr. Chernick's estimate of the Societal Cost and its composition.

b) Please indicate to which extent Societal Costs are measured and employed in Minnesota and Wisconsin.

c) Please indicate to what extent carbon market abatement costs are included in MH's export prices in MISO.

d) Please indicate what level of GHG costs should be included in determining the total Societal Cost.

Response:

a) Mr. Chernick has not developed an estimate of societal marginal costs for rate design or DSM valuation. If the Board indicates that it wishes Hydro to use the Societal Test, or even to consider and report it seriously, Mr. Chernick would be happy to work with Hydro in developing such an estimate. To date, Hydro has refused to provide the derivation of its marginal costs or provide the data from which Mr. Chernick could compute marginal costs.

b) Minnesota has established externality values, but it is not clear that externalities result in any decisions changing. Minnesota also passed a Next Generation Energy Act in 2007 that sets statewide greenhouse emission caps, but other than standards for renewables and efficiency, it is not clear what actions will be required for electric utilities. The Minnesota Climate Change Advisory Group Final Report does not recommend any requirements for electric utilities, beyond currently mandated efficiency and renewable-energy targets, T&D upgrades, and a small amount of distributed renewables.

c) No carbon market abatement costs are included in short-term sales. Mr. Chernick does not know what carbon price, if any, the MISO utilities anticipated at the time they negotiated long-term contracts with Hydro.

d) While Mr. Chernick has not personally reviewed the literature on carbon pricing, it is likely that the social cost of carbon is at least on the order of the $80/ton estimated by Synapse Energy Economics in Attachment PUB/GAC-7.

PUB/GAC 8 Reference: Page 19 & 20, Valuing Environmental Attributes

a) Please provide your understanding of MH's value of reduced GHG in the MISO market.

b) Please indicate your understanding of whether there is any explicit pricing for environmental attributes in MH's contracts or in the MISO Day Ahead and Real Time markets.

c) Please explain how Mr. Chernick would value environmental attributes in the fuel switching analysis.

Response:

a) Mr. Chernick does not understand the reference to "MH's value of reduced GHG in the MISO market." Hydro has not provided any projection of the future prices of

greenhouse gases in MISO or otherwise, other than an estimate of market prices in an earlier version of the Western Climate Initiative.

b) Hydro has refused to provide its export contracts or details on their contents, so Mr. Chernick does not know "whether there is any explicit pricing for environmental attributes in MH's contracts." The only "explicit pricing for environmental attributes...in the MISO Day Ahead and Real Time markets" would be for the market value of NOx and SO_2 allowances, which are currently quite low.

c) It is not clear that environmental attributes would be particularly critical in the fuel-switching analysis, since Hydro has estimated that the use of electricity for space and water heating fails even a narrowly-construed TRC test, without externalities. In general, Mr. Chernick would add to the direct avoided costs the non-internalized costs of uncontrolled pollutants. Assuming that the marginal sources displaced are primarily in the US and that a cap-and-trade system is in place for SO_2 and NOx, the residual environmental costs avoided by Hydro exports would be from particulates, mercury (and to a limited extent, other toxics) and greenhouse gases (mostly CO_2, and potentially methane emissions from the production and transportation of natural gas and coal). As a practical matter, Mr. Chernick generally relies on the control costs required to meet current and anticipated emission limits. In some cases, directly estimating the damages due to incremental emission is possible, but the estimation and discounting of damages is contentious and uncertain. Where environmental regulators have established a shadow price for controls in dollars per tonne, utility regulators are often well-advised to rely on that value rather than attempt to conduct a parallel analysis with less expertise. In some cases, the shadow price is the benefit of reduced emissions from fuel-switching, energy-efficiency or other measures, since total emissions will be controlled by a cap and the cost avoided will be the cost of controls on some marginal source.

PUB/GAC 9 Reference: Page 20, Emissions Displacement

a) Please discuss how and to what extent MH exports into MISO have resulted, or will result, in coal generation retirements.

b) Is there a possibility that supplementing an existing coal based portfolio with clean MH electricity may extend the life of some coal plants?

Response:

a) It is not generally possible to determine the reasons for the retirement of any particular coal unit. Most retirements are driven by a combination of requirements for

ATT POB/GAC -

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement for RPS class n in year i, from Exhibit 3-9 in Deliverable 3-1.

l = losses from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are $30/MWh and the RPS percentage is 10%, the avoided RPS cost to a retail customer would be $30 × 10% = $3/MWh. Detailed results from Appendix C are incorporated into the Appendix B Avoided Cost Worksheets by costing period. The year-by-year RPS percentages for each RPS tier are shown in Appendix C.

The levelized RPS price impact for the 2012 to 2026 period, in 2011$ per MWh of load, is shown below:

Exhibit 6-50: Levelized RPS Price Impact (2012-2026)

Avoided RPS Cost by Class ($/MWh of Load) Levelized Price Impact 2012 – 2026 (2011$)						
	CT	ME	MA	NH	RI	VT
Class I	$1.77	$0.87	$1.74	$1.31	$1.41	$0.50
All Other Classes	$0.40	$0.05	$3.24	$0.99	$0.01	$0.00
Total	**$2.17**	**$0.92**	**$4.98**	**$2.30**	**$1.43**	**$0.50**

6.6. Externalities

Externalities are impacts from the production of a good or service that **are not** reflected in price of that good or service, and that are **not** considered in the decision to provide that good or service.[174] Air pollution is a classic example of an externality, as pollutants released from a facility impose health impacts on a population, cause damage to the environment, or both. The costs of those health impacts and ecosystem damages are not reflected in the price of the product and are generally not borne by the owner of the pollutant source. These costs are thus external to the financial decisions pertaining to the source of the pollutant. Therefore, externalities equal the total value of the adverse impacts minus the value of those impacts reflected in market prices.

In Chapter 2, we identify the impacts of pollutants that **are** reflected in market

[174]In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

prices in New England. There are many significant air pollutants associated with electric generation, but NO_x, SO_x, and CO_2 are the three primary pollutants that are currently subject to federal and/or state or regional regulation. Our electric market simulation model incorporates assumptions regarding compliance costs for those emissions as part of its estimation of the market price of electricity. The simulation model includes these costs when calculating bid prices and making commitment and dispatch decisions.

The Scope of Work for AESC 2011 asks for the heat rates, fuel sources, and emissions of NO_x, and CO_2 of the marginal units during each of the energy and capacity costing periods in the 2011 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in pounds per MWh, respectively, during each costing period.

Exhibit 6-51 and Exhibit 6-52 summarizes the marginal heat rate and marginal fuel characteristics from the model results. The results of the two exhibits are based on the marginal unit in each hour in each transmission area, as reported by the model. Once the marginal units are identified, we extracted the heat rates, fuel sources, and emission rates for the key pollutants from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market.

Exhibit 6-51: 2011 New England Marginal Heat Rate by Pricing Period (Btu per kWh)

	Season and Period				
	Summer		Winter		Grand Total
	Off Peak	On Peak	Off Peak	On Peak	
Average Heat Rate (BTU/kWh)	9,543	10,188	9,161	8,494	9,183

Exhibit 6-52: 2011 New England Marginal Fuel Type

	Season and Period				
	Summer		Winter		
Fuel Type	Off Peak	On Peak	Off Peak	On Peak	Grand Total
Natural gas	70%	68%	64%	83%	71%
Oil	0%	1%	1%	1%	1%
Coal	24%	29%	24%	15%	22%
Nuclear	5%	1%	11%	1%	5%
Biomass	1%	1%	0%	0%	0%
Other	0%	0%	0%	0%	0%
Renewable	0%	0%	0%	0%	0%
Grand Total	100%	100%	100%	100%	100%

Our discussion of the methodology that we employ is discussed below:

We calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of pounds per MWh. We do this by multiplying the quantity of fuel burned by each marginal unit by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

$$\text{Marginal Emissions} = [\text{Fuel Burned}_{MU}\ (\text{MMBtu}) \times \text{Emission Rate}_{MU}\ (\text{lbs/MMBtu}) \times 1\ \text{ton}/2000\ \text{lbs}]/\text{Generation}_{MU}\ (\text{MWh})$$

Where:

Fuel Burned$_{MU}$ = the fuel burned by the marginal unit in the hour in which that unit is on the margin,

Emission Rate$_{MU}$ = the emission rate for the marginal unit, and

Generation$_{MU}$ = generation by the marginal unit in the hour in which that unit is on the margin.

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England in pounds per MWh. The emission rates are presented by modeling zone, however differences between zones tend to be relatively insignificant.

Exhibit 6-53: 2011 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

CO2 (lbs/MWh)	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
NE - Boston	1,211	1,330	1,140	1,079	**1,163**
NE - CT Central-Northeast	1,240	1,346	1,146	1,090	**1,176**
NE - CT Norwalk	1,240	1,347	1,148	1,090	**1,177**
NE - Northeast MA	1,240	1,347	1,148	1,090	**1,177**
NE - New Hampshire	1,225	1,341	1,136	1,082	**1,167**
NE - Rhode Island	1,230	1,354	1,148	1,070	**1,170**
NE - Southeast MA	1,216	1,336	1,130	1,072	**1,159**
NE - Vermont	1,216	1,335	1,131	1,072	**1,159**
NE - West Central MA	1,230	1,347	1,143	1,086	**1,172**
NE - CT Southwest	1,229	1,350	1,143	1,090	**1,174**
NE - Maine	1,201	1,306	1,133	1,005	**1,132**
Average	**1,225**	**1,340**	**1,140**	**1,075**	**1,166**

Exhibit 6-54: 2011 New England Avoided NOx Emissions by Modeling Zone and Pricing Period (lbs/MWh)

NOx (lbs/MWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Boston	0.646	1.076	0.635	0.477	**0.708**
NE - CT Central-Northeast	0.762	1.081	0.656	0.513	**0.753**
NE - CT Norwalk	0.757	1.084	0.656	0.514	**0.753**
NE - Northeast MA	0.708	1.094	0.640	0.491	**0.733**
NE - New Hampshire	0.698	1.100	0.647	0.452	**0.724**
NE - Rhode Island	0.664	1.083	0.634	0.461	**0.711**
NE - Southeast MA	0.664	1.083	0.634	0.461	**0.711**
NE - Vermont	0.716	1.092	0.654	0.495	**0.739**
NE - West Central MA	0.729	1.101	0.654	0.506	**0.747**
NE - CT Southwest	0.757	1.084	0.656	0.514	**0.753**
NE - Maine	0.663	1.041	0.727	0.429	**0.715**
Average	**0.706**	**1.084**	**0.654**	**0.483**	**0.732**

In this 2011 AESC report, we find that CO_2 has the most significant externality. We also conclude that the long-run marginal abatement cost of CO_2 is a practical and conservative measure of the full cost of carbon. In updating our recommendation from the 2009 AESC report, we review current literature on emissions reductions necessary to avoid the most dangerous impacts of climate change, as well as analyses of technologies available to achieve those emission reductions. We recommend that the Study Group uses a marginal abatement cost value which is based on the cost of controlling emissions.[175]

For AESC 2011, we recommend using a long-run marginal abatement cost (2011$) of $80 per short ton of CO_2. This is effectively a slight reduction in real dollars from our recommendation in AESC 2009 of $80 per short ton in 2009$ ($81.52 in 2011$). This estimate is still one-third higher than the value of $63 (2011$) per short ton recommended in AESC 2007. In 2011 approximately two percent of the $80 per ton is internalized in the market price of electricity, through RGGI, and 98 percent is an externality. By 2026, we estimate that approximately 49 percent of that amount will be internalized.

[175] This is an alternative to setting value based on monetized estimates of damages.

6.6.1. History of Environmental Externalities: Policies in New England

In the 1990's several New England states had proceedings dealing with externalities that influence current utility planning and decision-making.[176] In Massachusetts, dockets DPU 89-239 and 91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" and included consideration of many aspects of IRP including determination and application of environmental externalities values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $22 per ton of CO_2 (in 1989 dollars) (Exhibit DOER-3, Exhibit. BB-2, p. 26). Docket DPU 91-131 examined environmental externalities to develop recommendations of various approaches for quantifying the CO_2 externality value. The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate change into policies and regulation in the United States.[177] Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $22 per ton (in 1989 dollars).

6.6.2. Carbon Dioxide

Externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x and ozone, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios);

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[176] A more detailed description of the history of electricity generation environmental externalities and policies in New England may be found in AESC 2007 (p. 7-6–7-8).

[177] AESC 2009 provides more detail about the Massachusetts DPU Order in Docket DPU 91-131.

- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs.[178]

We anticipate that the "carbon externality" will continue to be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be adopted with sufficient stringency to link scientific research and evidence with long-term policy that would enable carbon-free resources to replace fossil-based generation lag, particularly in the United States.[179] The damages from the EPA's Criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications.

Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions, as well as relatively low NO_x emissions.

Based on knowledge of the electric system and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. The current RGGI

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[178] For example, the Clean Air Transport Rule, while currently in draft form, is expected to adjust the SO_2 and NO_x emissions caps downward with an ultimate effect of reducing SO_2 emissions approximately 73 percent from 2003 levels. Under the draft rule, annual emissions of SO_2 are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47 percent over the five-year compliance period. Annual NO_x emissions are capped at 1.4 million tons. As a result, while there will be some "external costs" associated with the residual SO_2 and NO_x pollution, these externalities are now relatively small. The EPA's proposed Air Toxics Rule governing electric utilities under section 112(d) of the Clean Air Act would do the same for emissions of mercury and other air toxics, while the proposed rule under section 316(b) of the Clean Water Act would minimize the externalities associated with the impingement and entrainment of aquatic organisms from power plant cooling water intake systems.

[179] On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

auctions and any federal CO_2 regulations only internalize a portion of the "greenhouse gas externality," particularly in the near term. Values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

6.6.3. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air or water pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs – one with higher hourly pay rate and higher risk than the other – can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. The damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the "damages" around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target–it depends upon what concentrations we ultimately reach (or what concentrations we reach and then reduce). This is exacerbated by the fact that we do not fully understand what changes in the earth's climate might occur assuming carbon dioxide concentrations continue to increase past the current 380 parts per million, toward a projected 450 parts per million (or even higher) climate change, and cannot project with certainty the levels at which certain impacts will occur.

A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Estimating damages is fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes

of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries.

These difficulties are evident when examining various existing damage estimates. A meta-study from 2008 by author Richard Tol compares 211 estimates of this "social cost of carbon," which represents the economic costs of the damages from climate change aggregated across the globe and discounted to the present.[180] These estimates come from 47 studies done between 1982 and 2006.[181] The figure below shows a scatter plot of these estimates over time. The social cost of carbon is shown on the vertical axis, expressed in 2011 dollars per short ton of CO_2. Due to the wide range of the distribution, this value is expressed in log terms. The year of the study is shown on the horizontal axis. These studies use different methodologies, discount rates, damage functions, physical impacts of climate change, and equity weightings across individuals in different parts of the world, all of which are reflected in the resulting damage cost estimates. Hence, estimates vary across time and no particular pattern emerges when examined together.

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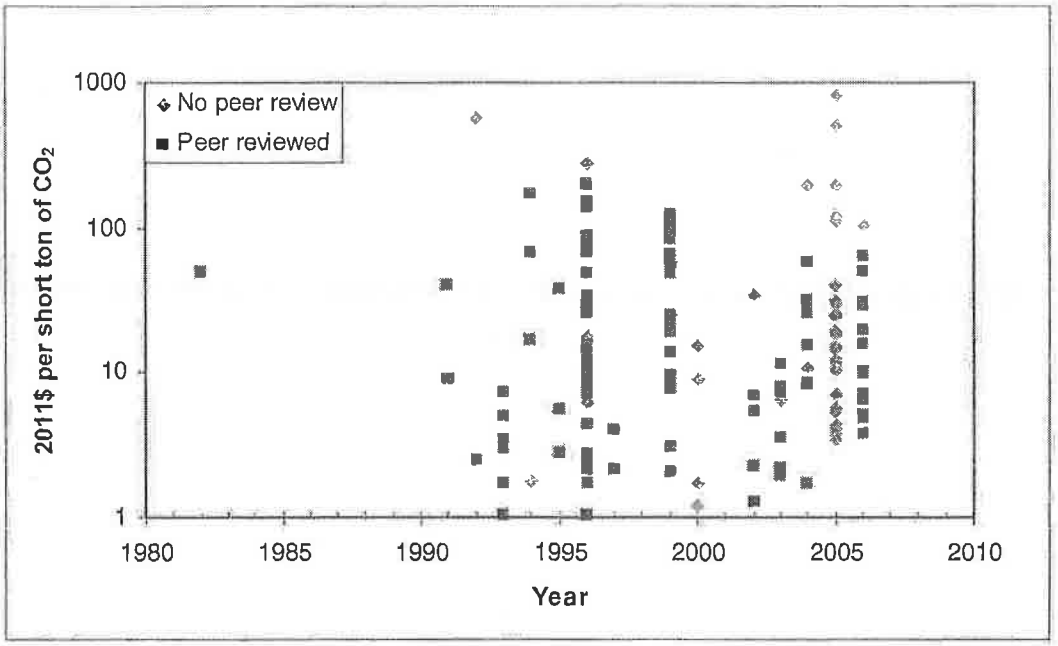
[180] Tol, Richard S.J. *The Social cost of Carbon: Trends, Outliers and* Catastrophes. Economics E-Journal. Vol 2, 2008-25. August 12, 2008.

[181] It should be noted that many of the studies included in the meta-analysis were authored or co-authored by Richard Tol.

Exhibit 6-55: Scatter Plot of Converted Values of Tol 2009 Societal Cost of Carbon



Conversely, the "control cost" methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a "regulators' revealed preference" concept. That is, if "air regulators" are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The fact that the "regulators' revealed preferences" approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost. The cost of control approach can also be based upon a "sustainability target" concept. With the sustainability target, we start with a level of damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target. It is important to note that, at this stage in our collective understanding of the science of climate change, as well as its social, economic, and physical impacts, the notion of a "sustainability target" is a construct useful for discussion, but not yet firmly established.

The "sustainability target" approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit

lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable).

6.6.4. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);
- This list of "physical damages" includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as "marginal" can be problematic; and

The impacts of climate change are non-linear and non-continuous, including "feedback cycles" that can most reasonably be thought of in terms of thresholds

beyond which there are "run away damages" such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation—a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, we propose taking a practical approach consistent with the concepts of "sustainability" and "avoidance of undue risk." Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

6.6.4.1. What is Current Understanding of the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, we reviewed current science and predicted policy impacts that have been released since AESC 2009.

We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change's most recent Assessment Report (IPCC 2007a, 15) indicates that concentrations of 445 to 490 ppm CO_2 equivalent correspond to 2° to 2.4°C increases above pre-industrial levels. A comprehensive assessment of the economics of climate change, Stern (2007) proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2. Recent research indicates that achieving the 2°C goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent (Meinshausen 2006).

The Intergovernmental Panel on Climate Change (IPCC 2007, Table SPM5) indicates that reaching concentrations of 450 to 490 ppm CO_2 equivalent requires reduction in global CO_2 emissions in 2050 of 50 to 85 percent below 2000 emissions levels. Stern (2007, xi) says that global emissions would have to be 70 percent below current levels by 2050 for stabilization at 450 ppm CO_2 equivalent. To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 to 90

percent below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible (den Elzen and Meinshausen, 2006).

In the United States, several states have adopted state greenhouse gas reduction targets of 50 percent or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). The state of Massachusetts has set targets for even greater reductions of greenhouse gases. The Global Warming Solutions Act (GWSA) was signed into law by Governor Deval Patrick in August 2008. The Act calls for initial reductions in greenhouse gas emissions of between 10 percent and 25 percent below 1990 levels by 2020. In the *Massachusetts Clean Energy and Climate Plan for 2020*, released on December 29, 2010 by the Massachusetts Executive Office of Energy and Environmental Affairs, the reduction target was set at 25 percent below 1990 levels. The Global Warming Solutions Act also has emissions reduction targets for 2030 and 2040, leading to an emissions reductions target of 80 percent below 1990 levels by 2050.

6.6.4.2. Cost of Stabilizing CO_2 Emissions

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued four assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (in 1990, 1995, 2001, 2007). The IPCC's Fifth Assessment Report is due in 2014.

IPCC (2007a) indicates that reductions on the order of 34 gigatons would be necessary to achieve an 80 percent reduction below current emission levels. [182] IPCC (2007b, p. 45) estimates that up to 31 gigatons in reductions are available for $98 per short ton of CO_2 or less (Working Group III Summary for Policy Makers) in 2011 dollars.[183]

For the 2011 AESC, we have examined other more recent studies, produced since July 2009, on the costs of achieving stabilization targets that include the following, and converted the given values to 2011$ per short ton of CO_2:

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[182] 2000 emissions levels were 43Gt CO_2-eq. IPCC (2007a).

[183] This value, expressed in Table TS.3 in 2006 dollars per metric ton, is $97 per short ton of CO_2 in 2011 dollars ($100 metric ton of $CO_2 \times 1.07$ [2006 to 2011 GDP values] $\times$ (1 metric ton/1.102 short ton)).

- In 2010 McKinsey and Company (McKinsey 2010) released an update to its second version of the Global Greenhouse Gas Abatement Cost Curve[184] in order to examine the impacts of the global financial crisis on carbon economics and emissions reductions.[185] The analysis came to the conclusion that the global financial crisis and resulting economic downturn has had a small impact on long-term emissions, and thus the size of the required emission reductions remains essentially the same. A stabilization level of 550 ppm, consistent with a temperature increase of 3°C, would result in a marginal abatement cost of $101 per short ton of CO_2. McKinsey increased its estimate from $75 per short ton in 2009 in order to include known carbon capture and storage (CCS) controls. The amount of energy necessary to run CCS controls leads to increases in the CO_2 abatement cost. Achieving a stabilization level of 450 ppm, consistent with a temperature increase of 2°C, would result in a marginal abatement cost of $126 per short ton.[186]
- In the World Energy Outlook 2010, the International Energy Agency (IEA 2010a) has modeled the implications and results of three international policy framework scenarios: (1) the Current Policies Scenario, in which country CO_2 policies are held constant as of mid-2010; (2) the New Policies Scenario, which takes into account broad policy commitments and plans that countries have announced but not yet implemented; and (3) the 450 Scenario, which stabilizes CO_2 levels at 450 ppm to limit temperature increase to 2°C. Under the Current Policies Scenario, the IEA projects carbon prices of $46 per short ton of CO_2 in 2035, and a price of $39 per short ton under the New Policies Scenario. Prices under the 450 Scenario are projected to be $111 per short ton for OECD+ countries and $83 per short ton for Other Major Economies. [187]

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[184] The original Global Greenhouse Gas Abatement Cost Curve was released in 2007. The second version was released in 2009. The 2010 update is known as Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.

[185] McKinsey and Company did not update technology projections, but rather focused on updating the macroeconomic effects on emissions in the business-as-usual (BAU) scenario, and the resulting impact on emission reduction economics. A small number of model upgrades and enhancements were also performed.

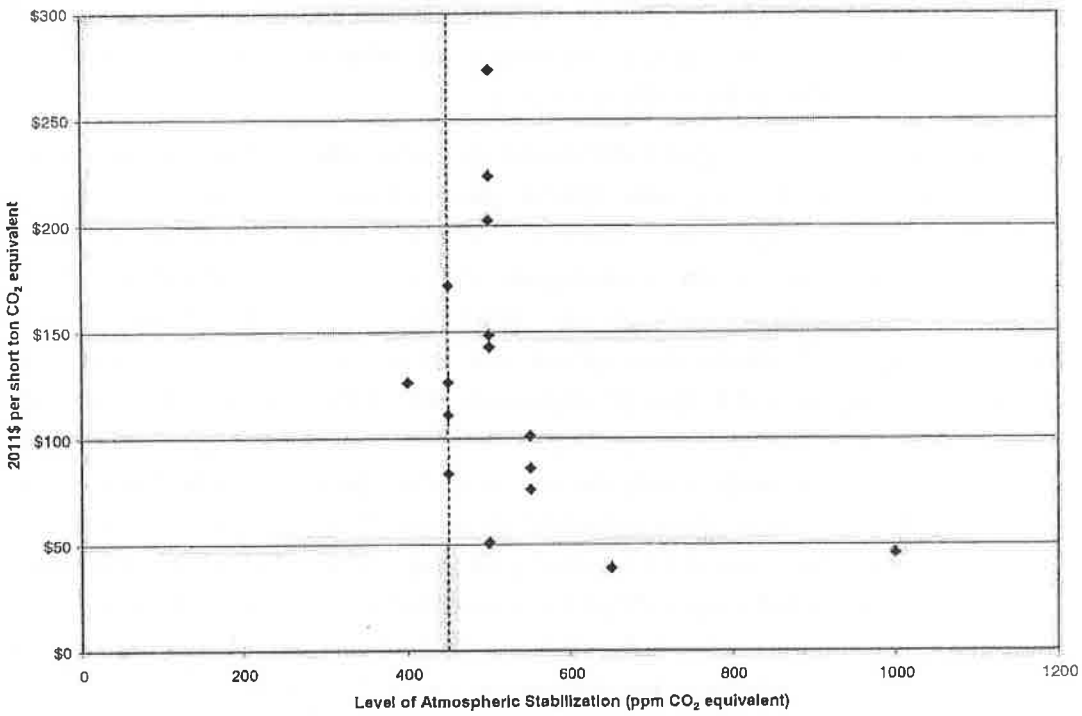
[186] The report values are expressed in 2005 Euros per metric ton of CO_2 of 80 and 100 Euros respectively.

[187] OECD+ countries include all OECD countries, as well as non-OECD countries in the European Union. Other Major Economies includes Brazil, China, the Middle East, Russia, and South Africa.

- The IEA examines four policy scenarios in its Technology Perspectives 2010, all of which reduce emissions of CO_2 by 50 percent from 2005 levels by 2050. In the Blue Map Scenario, these targets are achieved at a cost of $163 per short ton. If carbon capture and sequestration technologies are not available, the marginal cost of abatement increases to $273 per short ton. In the Blue Map case with high amounts of nuclear power, abatement cost is $148 per short ton. Finally, in the Blue Map case with high renewables, controls costs are $142 per short ton.

The results of these studies mentioned above, as well as additional studies by the same entities[188], are summarized in Exhibit 6-56. The dotted line is drawn at the value of atmospheric stabilization of 450 ppm CO_2 equivalent, which corresponds to a global temperature increase of 2°C above pre-industrial levels.

Exhibit 6-56: Summary Chart of Marginal Abatement Cost Studies



188 These additional studies include: (1) McKinsey & Company. 2009. "Pathways to a Low-Carbon Economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve."; (2) International Energy Agency. 2008a. *World Energy Outlook 2008*. Paris: International Energy Agency.; and (3) International Energy Agency. 2008b. *Energy Technology Perspectives 2008: Scenarios and Strategies to 2050*. Paris: International Energy Agency.

We recommend that the estimated long-run marginal abatement cost be used as a practical and reasonable measure of the societal cost of carbon dioxide emissions. This can be applied to carbon dioxide emissions reductions, derived from lower electricity generation as a result of energy efficiency, in order to quantify their "full value." A portion of this value will be reflected in the allowance price for emissions, and thus internalized in the avoided costs; the balance may be referred to as an externality. Based on a review of these different sources, and our experience and judgment on the topic, we believe that it is reasonable to use an estimated long-term marginal abatement cost (LT MAC) of $80 per short tCO_2 equivalent (2011$) in evaluating the cost-effectiveness of energy efficiency measures. This estimate is essentially the same as our AESC 2009 estimate for the LT MAC of $81.52 per short tCO_2 equivalent (2011$).

Thus, states that have established targets for climate mitigation comparable to the targets discussed in this Chapter, or that are contemplating such action, could view the $80/ton long term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets.

Estimates of long-run marginal abatement costs include a degree of uncertainty. These reflect the underlying assumptions about a variety of effects, among them the extent of technological innovation, the selected emission reduction targets, the technical potential of certain technologies, and international and national policy initiatives, along with a variety of other influencing factors. Of course, selection of this value requires multiple assumptions and cannot be definitive given the quickly evolving combination of scientific understanding of the causes, effects and scale of climate change, international policy initiatives, and technological advances. It will be necessary to continuously review available information, and determine what value is reasonable given information available at the time of reviews. A value of $80 per short ton of CO_2 reflects our experience that actual costs tend to be lower than modeled values,[189] and is a reasonable estimate of the long-run marginal abatement costs for achieving a stabilization target that is likely to avoid temperature increases higher than 2°C above pre-industrial levels.

6.6.5. Estimating CO_2 Environmental Costs for New England

Our estimates of the "external" or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the

[189] The long-run marginal abatement value of $80 per short ton CO_2 is slightly lower outside the range shown in Exhibit 6-6. The lowest value that would achieve atmospheric stabilization at 450 ppm as shown in the Exhibit is approximately $83.

forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated long term marginal abatement cost of $80 per short ton minus the annual allowance values internalized in the projected electric energy market prices. For AESC 2011, we repeat this calculation process for the RGGI only scenario. These values are summarized in Exhibit 6-57.

Exhibit 6-57: CO_2 Externality Calculations

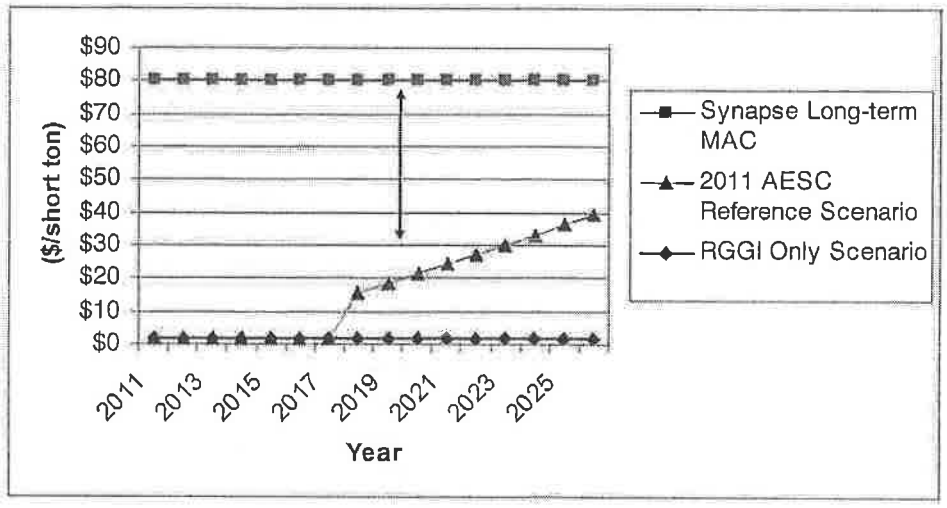
	LT MAC ($/short ton)	2011 AESC Reference Allowance Price ($/short ton)	2011 AESC Reference Externality ($/short ton)	RGGI Only Scenario Allowance Price ($/short ton)	RGGI Only Scenario Externality ($/short ton)
	a	b	c=a-b	d	e=a-d
2011	$80	$1.89	***$78.11***	$1.89	***$78.11***
2012	$80	$1.89	***$78.11***	$1.89	***$78.11***
2013	$80	$1.89	***$78.11***	$1.89	***$78.11***
2014	$80	$1.89	***$78.11***	$1.89	***$78.11***
2015	$80	$1.89	***$78.11***	$1.89	***$78.11***
2016	$80	$1.89	***$78.11***	$1.89	***$78.11***
2017	$80	$1.89	***$78.11***	$1.89	***$78.11***
2018	$80	$15.30	***$64.70***	$1.89	***$78.11***
2019	$80	$18.28	***$61.72***	$1.89	***$78.11***
2020	$80	$21.25	***$58.75***	$1.89	***$78.11***
2021	$80	$24.23	***$55.77***	$1.89	***$78.11***
2022	$80	$27.20	***$52.80***	$1.89	***$78.11***
2023	$80	$30.18	***$49.82***	$1.89	***$78.11***
2024	$80	$33.15	***$46.85***	$1.89	***$78.11***
2025	$80	$36.13	***$43.87***	$1.89	***$78.11***
2026	$80	$39.10	***$40.90***	$1.89	***$78.11***

Notes
Values expressed in 2011 Dollars
Allowance Prices from Exhibit 2-4
Inflation rate of 2%

The annual allowance values internalized in the projected electric energy market prices are shown in column b of Exhibit 6-57. The values are based upon a Synapse (Johnston 2011) forecast of the carbon trading price associated with anticipated carbon regulations starting in 2018. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2011 avoided electricity costs. The additional value in each year is the difference between the estimate of long run marginal abatement cost ($80 per ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 6-58 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the long-term marginal abatement cost (LT MAC) and the anticipated allowance cost; that is, the area above the line with triangles and below $80 per ton in the graph (shown between the double arrowed vertical line).

Exhibit 6-58: Determination of the Additional Cost of CO_2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex, such as varying the shape over time or developing a distribution to represent uncertainty, would go beyond the scope of this project and would stretch the available information upon which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical.

With regard to environmental costs, AESC 2011 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs. There are, of course, many impacts of electric power production. A number of those impacts are listed above in Chapter 2. However, the bulk of displaced generation in New England will be from existing and future natural gas plants. For these, CO_2 emissions are the dominant non-internalized environmental cost.

6.6.6. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 6-57 above are incorporated in the avoided electricity cost workbooks and expressed as dollar per kWh based upon our

analysis of the CO_2 emissions of the marginal generating units summarized in Exhibit 6-51.

At a minimum program administrators should calculate the costs and benefits of DSM programs with and without these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

The Massachusetts Department of Public Utilities recently clarified its policies with regard to the avoided costs of energy efficiency programs. In light of the requirement of the Green Communities Act[190] to implement all cost-effective energy efficiency resources, the Department opened an investigation to update its energy efficiency guidelines, including policies regarding the types of costs and benefits that can be included in cost-effectiveness screening in Massachusetts.

The Department affirmed the use of the Total Resource Cost test, and clarified how environmental benefits could be used in evaluating cost-effectiveness. The Department cited a Supreme Judicial Court (SJC) case that addressed the circumstances under which the Department may require Program Administrators to account for environmental impacts in evaluating energy resources. The SJC found that the Department could not require Program Administrators to consider environmental externalities in evaluating energy resources, as it did not have the statutory authority to do so.[191]

However, the SJC made it clear that the Department does have the authority to require Program Administrators to include the costs of compliance with current and reasonably foreseeable future environmental regulations, as these compliance costs would be incorporated in electricity prices over which the Department has clear jurisdiction. The Department identified the Global Warming Solutions Act and federal measures to control greenhouse gas emissions as examples of existing and reasonably anticipated future environmental regulations, and made it clear that "the Department expects Program Administrators to include estimates of such compliance costs in the calculation of future avoided energy costs."[192]

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[190] *An Act Relative to Green Communities*, Acts of 2008, Chapter 169, July 2, 2008.

[191] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, pages 14 and 15.

[192] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, page 17.

The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

6.6.7. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework (RGGI)

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Participant states include Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont, Maryland and New Jersey.[193] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Eleven rounds of auctions have currently occurred.

As currently designed, the program:

- Stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019;
- Allocate a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- Include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.

With carbon dioxide emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2011 to 2017 and an assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems,

[193] New Jersey Governor Christie has announced that New Jersey will withdraw from RGGI at the end of 2011.

and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;

- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- To the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may accrue as a result of increased sales of allowances from New York to other RGGI states. However, because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.

The first three of these points, above, would also apply to a national CO_2 cap and trade program. The fourth point, about leakage and boundaries, would apply as well, but to a lesser extent.

6.7. Social Discount Rate

The Project Team surveyed Study Group members and other sources to summarize the real discount rate used in cost-effectiveness models for energy efficiency programs in the six New England States as well as California, New York, Oregon and Washington. Appendix C summarizes results from our survey of real discount rates.

1 And I guess my question is: Are those
2 purely quantitative calculations? I mean, are you also
3 looking at some of the qualitative factors? For
4 example, my house is more comfortable.
5 MS. LOIS MORRISON: When we're looking
6 at the analysis, we take into consideration measurable
7 non-energy benefits when we're looking at the
8 technology screen -- or what we call a technology
9 screen or a product screen. So when we're deciding if
10 we're going to promote -- or we're investigating
11 whether increased insulation is valuable or -- or
12 something we want to promote, or better efficiency
13 showerheads, or even if we're looking at, say, CO2
14 sensors in commercial operations, we look at the
15 marginal value identi -- as outlined by Mr. Miles.
16 And if there's additional non-energy
17 benefits that can be measured, we include that value.
18 So the easiest one (1), of course, is water savings.
19 So we include the -- the reduced cost of water. But we
20 would -- and we will look at -- when we -- when we get
21 further into the discussion, we talk about societal
22 benefits. We talk of the societal test. We do look at
23 it from adding in just a 10 percent add --- adder to
24 say, Well, how close is it to being cost effective with
25 a 10 percent rider? You know, bring it into -- you

1 know, into account for those non-quantifiable benefits.
2 But it's not -- so -- so we will look at
3 it to see how close it is to being economic and if
4 those additional -- if that 10 percent might bring it
5 up. But we don't specifically say -- try to quantify
6 those things like increased comfort or higher
7 productivity for -- for -- because we've got more
8 daylight in -- in the work environment.
9 MR. RAYMOND LAFOND: My question is
10 more technical. When you talk of levelized costs,
11 what's the different between levelized costs for the
12 next thirty (30) years versus average costs for the
13 next thirty (30) years?
14 MR. TERRY MILES: Well, as I
15 understand, average costs would be a simple
16 mathematical average or mean of the numbers out in
17 time. Levelized cost uses a discount rate to bring
18 things back in time --
19 MR. RAYMOND LAFOND: So it's a
20 discounted rate?
21 MR. TERRY MILES: Yes.
22 MR. RAYMOND LAFOND: And you use a
23 discount rate of, what, 6 percent?
24 MR. TERRY MILES: Yeah, it varies, but
25 it's in that order for this, yeah.

1 what the impact on the -- from a societal perspective
2 is for the -- under the societal test, we added on a 10
3 percent rider just to -- what would it look like if we
4 were to do that, how does it influence the -- how does
5 it affect our economics?
6 MR. BOB PETERS: The -- the 10 percent
7 number was -- would be perhaps arbitrary, as opposed to
8 calculated?
9 MS. LOIS MORRISON: It's not
10 calculated, but it was consistent with what some other
11 jurisdictions we're looking at.
12 MR. BOB PETERS: Do you know which
13 other jurisdictions use the societal cost test as a
14 screen in determining whether or not the DSM program
15 makes it to market?
16
17 (BRIEF PAUSE)
18
19 MS. LOIS MORRISON: A number of
20 utilities use, and -- and I do believe Mr. Dunsky
21 referenced this in his evidence. There are a number of
22 utilities that use -- that -- that augment their
23 resource benefits by adding a rider on it, and that
24 rider has been designated or -- or denoted or -- or
25 established by their -- either their regulator or their

1 provincial government through policy, or through the
2 state government through policy.
3 And those utilities would be such as BC
4 Hydro, Efficiency from -- Efficiency Nova Scotia uses
5 it as part of their -- they're not a utility, but they
6 are the representative of the government for delivering
7 energy efficiency programs.
8 MR. BOB PETERS: I want to turn to page
9 343 of the book of documents and discuss another
10 concept raised by -- in the evidence of Mr. Dunsky.
11 And in essence I interpret Mr. Dunsky to be saying that
12 presently Manitoba Hydro has a sales -- sorry, a
13 savings to sales ratio of about decimal four-three
14 (.43).
15 Do you recall that from our previous
16 discussion, Ms. Morrison; the -- the savings to sales
17 ratio by Mr. Dunsky for Manitoba Hydro was
18 approximately point four-three (.43)?
19 MS. LOIS MORRISON: Yes, that's
20 correct.
21 MR. BOB PETERS: And if Manitoba Hydro
22 was to -- to increase its savings to sales ratio and
23 move up to the top quartile, it would probably have to
24 double its expenditures on DSM from 34 million up to
25 probably 65 million.

1 end product under the levelized utility cost test
2 that's -- that a -- that a measure has gone through?
3 MS. LOIS MORRISON: Yes. Page 315 of
4 the book of documents lists the levelized utility cost.
5 It -- it's not a test; it's a metric. I think that Mr.
6 -- that we -- that Mr. Dunsky actually pointed out.
7 But we just put it in as part of our economic analyses.
8 We've listed it there. But, yes, that's what the
9 levelized utility cost is for the individual programs.
10 MR. BOB PETERS: And when you look at
11 that number, what -- what is Manitoba Hydro seeking to
12 determine from that calculation?
13 MS. LOIS MORRISON: We look at both the
14 rate impact measure test and the levelized utility cost
15 test as a gauge by which to assess the level of
16 investment that the utility should make on behalf of
17 the ratepayer, in terms of affecting the market or
18 investing in -- in a change in the marketplace.
19 We -- what those tests will tell us is
20 to the extent which -- first, under the rate impact
21 measure test, the extent to which the program
22 investment may or may not affect rates going forward.
23 And I believe in -- I think that was -- that was quite
24 art -- well articulated by Mr. Thomson in his
25 testimony, that given our current financial position,

1 any new business case -- any new DSM programs that
2 Manitoba Hydro puts forward should have a sound
3 business case and that any of the programs going
4 forward should reduce the upward pressure on rates, not
5 increase the pressure on rates. And so we take that
6 into consideration in our design.
7 Now, when we're looking at our overall
8 portfolio, we were -- we're attempting not to have an
9 in -- an upward pressure on rates. We are taking that
10 into consideration, what's the best way to reach that
11 market. We also consider: What does the customer
12 who's participating benefit from, in terms of that
13 analysis?
14 And that -- that's going into some of
15 your -- the discussion on page 336 of the book of
16 documents. We're trying to balance to Utility's
17 investment against the customers' investments and the
18 benefit that they receive.
19 MR. BOB PETERS: Well, the levelized
20 utility cost is the level of investment the Utility is
21 prepared to make in the program?
22 MS. LOIS MORRISON: The levelized
23 utility cost is demonstrating what it's costing us to
24 achieve that kilowatt hour of energy.
25 MR. BOB PETERS: And is it arguable

environmental retrofits and low market energy prices (resulting in low utilization for some coal plants), both current and projected. The low market energy prices are due to the recession, low natural-gas prices, MISO wind development for renewable energy standards, energy-efficiency programs, and Hydro exports, among other factors. See Attachment PUB/GAC-9 for a list of the coal-plant retirements announced in and around MISO. Some statements by coal-plant owners attribute the retirements, in part, to low market prices and the availability of cheaper alternatives. With respect to Silver Lake, "Rochester's city utility decided it would be cheaper to buy electricity than to upgrade its decades-old generating station....'This is clearly an economic decision,' Jerry Williams, president of the city-owned utility's board, said of the vote to decommission the plant in 2015. 'Basically, we can go out on the open market and purchase electricity...at a lot less cost.'" (http://www.startribune.com/business/165367786.html)

b) Mr. Chernick does not see any way that increased exports from MH to MISO would be likely to extend the life of coal plants. With a purchase from MH, or lower market prices due to additional Hydro energy being available in the MISO markets, operating the coal plants would be less economic than with less energy from Hydro. It is conceivable that a purchase of X GWh from Hydro would allow a utility to meet some future greenhouse-gas requirement while retiring less coal capacity than would be retired if the same emissions reduction were met with increased generation from gas-fired combined-cycle plants, which would require about 2×X GWh of gas generation.

PUB/GAC 10 Reference: Page 23 Economic Screening Tests

To supplement the information provided on why the LUC should not be used, please identify and describe more fully which of the other screening tests employed by MH are considered irrelevant and why.

Response:

The Marginal Resource Cost ("MRC") test is not intended to be a definitive cost-effectiveness test. If the marginal costs and participant costs and benefits are properly stated, the MRC is a reasonable approximation of the Total Resource Cost test, for initial measure screening. It is not a substitute for the TRC test.

The Rate Impact Measure ("RIM") test has no place in screening DSM programs, measures or enhancement. Attachment PUB/GAC-10 presents Mr. Chernick's discussion of the problems with this computation in detail.

Mr. Chernick's testimony describes the problems with the Levelized Utility Cost ("LUC") test.

The Simple Customer Payback calculation is not useful as a screening test. Payback is often a useful indicator of customer acceptance, but whether customers accept a measure is often

more a function of program design (e.g., information, technical assistance, direct installation, contractor arranging, direction of incentives to the appropriate parties) than simple payback.

PUB/GAC 11 Reference: Page 24 Screening of DSM

Please elaborate on why benefits to the Province should be a consideration for DSM screening.

Response:

Mr. Chernick's references to "the Province" on page 24 of his direct testimony refer to the sum of benefits and/or costs to Hydro, Centra, and consumers of Manitoba electric, gas, and water consumers. While the Board might draw the lines differently, Mr. Chernick expects that it would view direct financial costs and benefits to utility customers within Manitoba to be relevant to utility decisionmaking.

PUB/GAC 12 Reference: Page 25 Ln 6-8

a) Please elaborate on how changes to the Marginal Cost estimate and using Total Resource Cost to screen DSM will lead to greater savings and lower total ratepayer costs.

b) Please comment on the impact on DSM savings and ratepayer costs, by continued low export prices.

Response:

a) The cited testimony states that "planning DSM based on minimizing total costs and using full marginal costs would almost certainly produce much greater savings and lower total costs to Manitoba power consumers." As explained in Mr. Chernick's testimony, Hydro appears to have rejected DSM options that would pass the TRC test, even with Hydro's current estimate of marginal costs. By definition, a measure that passes the TRC is expected to reduce total costs. Implementing additional cost-effective energy-efficiency would result in additional energy savings and reductions in total costs borne by ratepayers. As for the marginal costs, Mr. Chernick cannot determine whether Hydro has used appropriate estimates for full marginal costs, due to Hydro's refusal to provide the derivation of its estimates or data that would allow the testing of those estimates.

b) All else equal, lower export prices will reduce the marginal generation costs used in screening DSM and hence the number of measures that pass the TRC screen and the resulting energy savings. Since Hydro's screening of DSM remains mysterious, it is not clear how much DSM savings would change in response to a change in Hydro's marginal-cost estimates. Low export prices will tend to reduce Hydro's profits from exports, reducing the credit to domestic classes.

Measuring Rate and Bill Effects

Adapted from Direct Testimony of Paul Chernick

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV

Q: Is it appropriate to examine the effects of energy-efficiency programs on customer rates and bills?

A: Yes. As utilities ramp up energy-efficiency efforts to significant levels, the ratepayer impacts of the energy-efficiency portfolio should be examined carefully to flag any equity problems or disruptive rate shifts. If important inequities are identified in distribution of benefits and costs of energy-efficiency programs across classes, or among customers of varying sizes and types (e.g., space-heating versus other residential customers), the utility and the Board should correct the incidence of benefits (by emphasizing programs and delivery mechanisms that address underserved groups) and/or cost allocation (by changing the recovery of costs across classes, seasons, sales blocks, and other billing determinants).

More broadly, the equity effect of an energy-efficiency program depends on the following factors:

- whether the customer group served by the program is otherwise served more or less than other groups;
- whether the customer group served by the program is more in need of assistance to overcome the barriers to efficiency;
- whether the program is available to a large group of customers;
- whether the magnitude of the program results in a significant rate effect;
- the extent to which the program permanently transforms markets, so that higher-efficiency equipment and designs become standard practice

and even non-participants in the program wind up with better equipment and lower bills.

Energy-efficiency programs are not the only utility activities that result in rate effects. Many utility investments, including most cost-effective generation plants, raise bills in the short term and reduce bills over the longer term. Investments made to accommodate fast-growing customers and classes often increase bills to slower-growing customers. The costs of investments that reduce fuel and purchased-power costs are often allocated among customer classes very differently than the costs the investments avoid. The Commission tolerates these distributional effects to minimize costs and maximize benefits to customers as a whole over time.

Q: Is the Rate Impact Measure (RIM) a useful metric to assess the equity of the energy-efficiency portfolio?

A: No. The RIM is a very crude metric, invented in the 1970s, the very early days of utility energy-efficiency programs. The RIM has been rejected by utilities and regulators serious about promoting energy efficiency because it does a poor job of measuring rate effects (its stated purpose), and a worse job of measuring the fairness or equity of an energy-efficiency portfolio. The RIM has in the past been an excuse not to pursue energy-efficiency; whenever lost revenues exceed avoided costs, almost all efficiency efforts would fail the RIM.

The RIM is the ratio of two present values over the measure lifetime: the present value of avoided costs divided by the sum of utility costs and lost revenues. The RIM does not fulfill any of the following analyses:

- reflecting the effect of energy-efficiency programs on customer bills,
- estimating the effects on the various rate classes,

- determining whether the rate effects of particular measures or programs are increasing or decreasing the fairness of the distribution of net benefits among classes,
- estimating rate or bill effects by year.

Q: Is the RIM used in program or measure screening in any jurisdiction with significant energy-efficiency programs?

A: Not that I am aware of. So far as I can tell, even California, which originated the RIM, has never used it in any substantive manner.

Q: Does any jurisdiction use a test like the RIM to screen other activities, such as supply additions and rate design?

A: Not that I am aware of. No other utility activity is singled out for comparable treatment.

Q: What are the specific problems with the RIM test as a metric for efficiency?

A: I have identified seven distinct problems with the RIM. First, the RIM does not project percentage changes in rates and bills, or any other measure that would be useful to a decision maker concerned about rate levels. For example, in its 2005 resource plan report, British Columbia Hydro identified seven programs with RIM ratios of 0.6 or 0.7, which looks like a very serious rate effect. In fact, Hydro determined that those programs would have miniscule effects on rate, ranging from 0.0002¢/kWh to 0.0089¢/kWh.[1] According to this analysis, even the program with the

[1]Note that these rate impacts are described in cents, not dollars. Because these rate effects are much smaller than the Commission would normally see, it may be useful to restate them as $0.000002/kWh to $0.000089/kWh, or $0.002/MWh to $0.089/MWh.

largest effect on rates would increase rates less than 1/100 of a cent per kilowatt-hour. Any non-participants who chose to participate in any of Hydro's efficiency program would almost certainly save more than the miniscule costs that might be shifted to them by low-RIM programs.

Second, the RIM purports to measure the effect of a utility action on rates. Programs passing the Utility Cost Test and Total Resource Cost Test will generally reduce the present value of total revenue requirements, average utility bills, and total costs of energy services, including the costs paid directly by participants. Thus, even if rates rise, energy consumption will fall by a larger percentage, resulting in a net decrease in bills. The Commission and utilities should be striving to reduce the total dollars that customers are paying for their energy services, not necessarily the rate per kilowatt-hour. After all, consumers write checks for bills, not for rates. And reducing bills will leave customers with more income to spend on other needs, while reducing the cost of doing business and increasing the economic competitiveness of the state's industries.

Third, the RIM does not indicate how the program affects each rate class. Depending on the recovery mechanisms for energy-efficiency costs and lost revenues, and on the allocation of the avoided costs, any overall rate increase may be isolated to the rate classes using the program. If all customers in the class can participate in the programs, everyone's bills may be lower, even if their rates are higher.

Fourth, the RIM does not measure rate and bill effects well because the magnitude of the rate effects of any utility action depend on the timing and magnitude of the program, and cannot be usefully measured on a project-specific or measure-specific basis. The RIM is a rough measure of only the average effect on rates, over a long period of time.

Fifth, the non-participants in one program may be participants in other programs, and non-participants in the first year may be participants in later years. Over time, portfolios of energy-efficiency programs should be designed to offer direct benefits to as many customers as feasible. If the RIM is used to reject many programs, more customers will be non-participants and be more likely to pay more than they save from energy-efficiency programs, at least for some years. Estimates of rate, bill and equity effects are only meaningful on a portfolio basis.

Sixth, the energy-efficiency option that most conclusively fails the RIM may also increase the equity of the portfolio. For example, suppose that a program targeting refrigeration and cooking use of small restaurants has a RIM benefit/cost test of less than 1.0. For that segment of the small-commercial class, this may be the only program in which the customers can participate in a major way. Hence, even if the program increases rates for non-restaurant small-commercial customers, it would help to balance the portfolio by ensuring that all portions of the class have access to significant savings.

Finally, a serious defect of the RIM test is that it disproportionately focuses on the small near-term rate impacts of energy-efficiency programs while entirely ignoring the much larger rate impacts associated with future large capital investments in new generation assets. It is clear that that effective energy-efficiency program can minimize or defer the necessity for such large capital investments. As such, any near-term small rate impacts associated with energy-efficiency programs can be an effective tool for minimizing ratepayer (and overall macroeconomic) exposure to much-larger double-digit rate increases associated with multi-billion-dollar capital-construction projects.

Avoiding adverse effects on groups of customers is certainly an important consideration for utilities and the Commission. Those effects can be better assessed by analyses such as those performed by BC Hydro, or more detailed analyses of rates that would be charged to specific customer groups, rather than the uninformative RIM test.

Manitoba Hydro 2013 & 2014 GRA

Information Requests of the Public Utilities Board

November 22, 2012

PUB/CAC & GAC 1 Reference: Figure 1 Benchmarking

a) Please provide a schedule of supporting calculations for MH's and other Canadian jurisdictions' position on the chart with references to supporting documents.

Please see accompanying Excel file.

In reviewing the file, we noticed an error (incorrect cell link) that resulted in an understatement of Hydro-Quebec's 2010 savings. Listed as 0.40%, the correct value is 0.55%. We apologize for the error.

b) Please explain why Mr. Dunsky did not include jurisdictional comparisons with Ontario, Saskatchewan and Alberta and what factors warranted their exclusion?

The benchmarking exercise used readily-available data covering all U.S. states. In order to include a Canadian perspective, we supplemented that with data from the Canadian provinces that were the focus of the more detailed, forward-looking benchmarking exercise we were already undertaking. This allowed us to cover some 90% of North American regions while minimizing the time and cost of the exercise. I do not believe that the inclusion of Ontario, Saskatchewan and Alberta would have materially changed the results.

c) Please comment on MH's relative position to Canadian peers?

Note to reader: the value for Hydro-Quebec was based on an incorrect cell link and has been corrected to 0.55% (see above).

In 2010, the energy savings generated by Hydro-Québec's programs were somewhat greater (27%) than Manitoba Hydro's, while savings generated in B.C. and Nova Scotia were nearly double those of Manitoba Hydro (92% and 96% higher, respectively). While one should use a single year comparison with caution, none of these values are anomalies: reported 2010 savings in the provinces with a history of DSM (B.C., Manitoba, and Québec) all fell roughly at the mid-point between their 2008 and (expected) 2012 savings. In Nova Scotia's case, annual savings are growing rapidly, and 2010 reported savings are far below those of both 2011 and 2012.

d) Please explain what additional annual expenditures MH will be required to make given current levels to achieve the top quartile position. Identify programs to be targeted.

Assuming the top quartile of performance in 2010 remains the same going forward, at least in the aggregate, Manitoba Hydro would need to achieve a minimum of approximately 1% of savings / sales to enter the top quartile. Based on current load, this would require incremental annual savings of 220 GWh.

At a typical yield of $0.30/kwh (first year)[1], the annual budgetary requirement for Manitoba Hydro would be about $65 million.

I have not undertaken a complete assessment of Manitoba Hydro's planned portfolio of programs, though I identified in my testimony some examples of opportunities that do not seem to be targeted. Broadly speaking, each program would need to be revisited with a view to maximizing both depth of savings and participation rates.

PUB/CAC & GAC 2 Reference: Dunsky Rpt Page 6

a) Please provide a comparison between the savings over sales versus share of forecast growth approaches for MH

See response to (b) below.

b) Please explain what factors have led to the share of forecast growth not being used as a metric.

There are two primary factors:

First, savings / sales has evolved to become the industry standard benchmarking metric.

Second, the alternative "share of forecast growth" metric would have been uniquely unfair to Manitoba Hydro in the current North American economic context. As economic growth – and with it demand growth – has temporary slowed or halted in many US states, this indicator would likely have pointed to much higher ratios for states with the most affected economies, compared with Manitoba that has largely weathered the storm. The resulting values for these US states would have appeared artificially impressive, but would have been the result of a temporary economic anomaly.

c) Given MH's planned investments in new Generation and Transmission please explain which metric is most appropriate in measuring DSM efforts.

It depends on the purpose of the metric. If the purpose is to compare DSM goals and performance against other regions, the savings/sales metric is more appropriate for the reasons noted above. If the purpose is to set internal targets, both can be of value. For example, Manitoba might wish to adopt a target or requirement for DSM to cover X% of projected load growth; the resulting planned savings could then be benchmarked against other regions using a % of sales metric.

PUB/CAC & GAC 3 Reference: Dunsky Report Page 8

Please describe how rate structure changes have been utilized in other jurisdictions and comment on the applicability of these rate structures in the context of MH. Provide specific examples.

[1]. Manitoba Hydro's current planned cost is $0.28/kWh (first year).

1 plan. This plan is then included as one of the
2 resource options in developing the Corporation's
3 integrated resource plan for meeting Manitoba's future
4 electricity requirements.
5 Manitoba Hydro recognizes that when
6 compared on a percent of sales basis, some regions are
7 pursuing higher levels of energy savings than what is
8 being planned for under the Corporation's 2011 Power
9 Smart plan. While Manitoba Hydro agrees that using a
10 savings ratio metric in general is valid for comparing
11 energy conservation efforts between regions, such
12 comparisons must be done with considerable caution
13 where regions differ -- where regional differences
14 exist, such as the difference in load characteristics
15 and marginal cost considerations.
16 Conclusions should not be drawn solely
17 upon benchmark metric comparisons, as such comparisons
18 may lead to misleading or ambiguous conclusions. For
19 example, in the comparison presented by Mr. Dunsky, the
20 analyses undertaken among regions having considerable
21 differentials in marginal cost values, which the Man --
22 which Manitoba Hydro's marginal costs being
23 considerably lower than a number of regions.
24 As such, it is expected that regions
25 with higher marginal cost values will have more

1 economic opportunities available to them. Manitoba
2 Hydro's Power Smart plan is based on the unique
3 situation of having marginal cost values which are
4 considerably lower than regions such as bus -- British
5 Columbia, Nova Scotia, and Vermont; having marginal
6 values where the export electricity market accounts for
7 a significant component of those marginal cost values,
8 as opposed to deferral of new generation; and having
9 load characteristics consisting of a large, diverse
10 industrial load, significant electricity use for space
11 and water heating combined with high degree -- high
12 heating degree days.
13 Manitoba Hydro recognizes that its DSM
14 targets are declining but would assert that this is a
15 reflection of Manitoba Hydro's consistent long-term
16 engagement in DSM and a diminishing availability of
17 economic energy-efficient opportunities remaining in
18 the Manitoba market.
19 Manitoba Hydro agrees with aggressively
20 pursuing energy-efficient opportunities. However, the
21 Corporation believes it's important to primarily pursue
22 those opportunities which are economic.
23 MS. ODETTE FERNANDES: Will there be
24 any changes on how Manitoba Hydro will establish its
25 DSM targets in the future, including any external

1 Minnesota, and Vermont?

2 MS. LOIS MORRISON: Well, as I

3 mentioned in my direct testimony, we support the

4 concept of comparing to metrics; however, it has to be

5 done with caution and in consideration of all the --

6 the differences between the two (2) markets or between

7 the markets.

8 As I mentioned, Vermont, Nova Scotia,

9 and British Columbia, all have significantly higher

10 marginal values associated with the energy savings,

11 which means that technologies that would be economic

12 there may not be economic in Manitoba. The other issue

13 that we had talked about was the presence of -- and Mr.

14 Dunsky did attempt to -- to look at it from the

15 perspective of the heating degree days, but what was

16 not considered was the percentage of electric heat

17 associated with that.

18 And when you have that in the metric,

19 what it does is it drives up the size of your

20 denominator. So, when you're doing the math, we're

21 starting out with a much larger denominator just

22 because of the fact that we have higher degree heating

23 -- degree days heating and a higher percentage of

24 electric heat. And -- and there has been discussion

25 that -- well then that means you have more

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PUB/CAC & GAC 16 Reference: Page 33 Economic Screening

a) Please provide a description of each of the screening methods and the relative strengths and weaknesses related to each approach for determining the level of DSM investments.

Screening methods are both valuable (for providing guidance) and subject to misuse (when miscalculated, or when used in ratio form to optimize portfolios).

Currently in North America, there are two *types* of tests that are commonly used as primary screens:

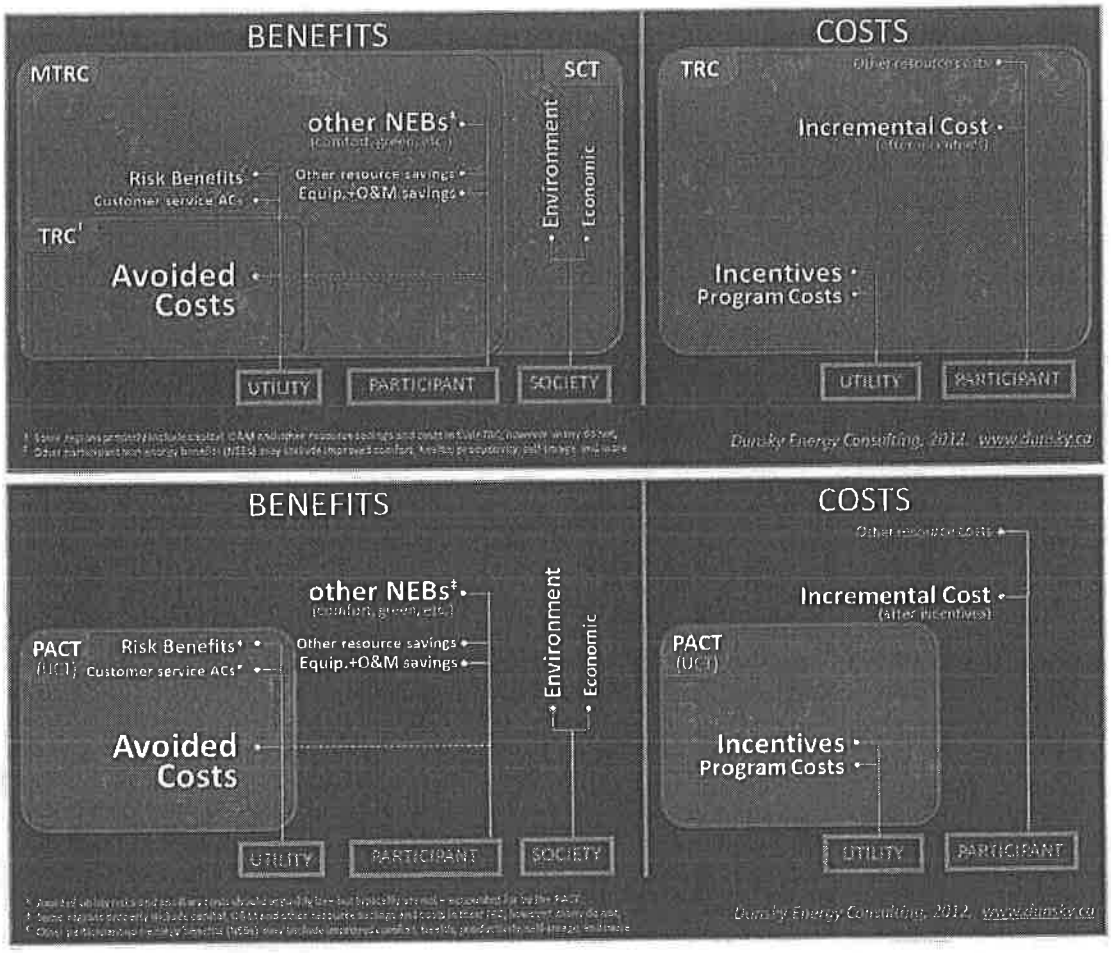
- **TRC:** The "TRC" is meant to account for the sum of utility and participant perspectives. A variant of the TRC, the "SCT", further accounts for societal benefits. The TRC is increasingly controversial, as a growing number of studies are finding that it is being used incorrectly. In so doing, the TRC as commonly applied misses significant benefits – primarily but not exclusively participant benefits –, while overstating costs. A number of regions, especially those that lead on DSM, are now moving to either substantively modify the TRC (sometimes renaming it the Modified TRC, or "MTRC"), or move to the Program Administrator Cost test (PACT, previously known as the Utility Cost Test).

- **PACT:** The PACT treats DSM on the same footing as new supply, i.e. it accounts for the utility's cost, and the utility's benefit (avoided costs). It is a simpler, more straightforward approach. It is considered both less comprehensive, and fairer.

- **Others:** I understand that Manitoba Hydro continues to use the RIM test (though it is not clear to what extent). I note that in North America today, the RIM is rarely if ever used as a primary screening test.

Across our cohort regions, one (Vermont) use the SCT, two (B.C. and Massachusetts) use a substantively Modified TRC, one (Minnesota) uses the a combination PACT and SCT, and one (N.S.) uses a classic TRC, though this is currently under review. In all cases, these are applied at either the program or sector level.

The following charts illustrate the boundaries of the various tests *as they are commonly applied.*



As important as the choice of tests may be, equally critical is how they are used. For example, while the tests may provide guidance, they should only be used as hard screens at either the portfolio (plan) or sector level. It is entirely normal for plans to contain individual measures or programs that do not pass the primary test, to the extent they serve other purposes that are hard to quantify (e.g. reinforcing a brand, taking the role of "loss leader" in a retail strategy, or ensuring equity within a given rate class).

Finally, it is also critically important to choose appropriate metrics. Most tests can be expressed in one of three ways: absolute terms (NPV), ratios (B/C), or unit terms ($/kWh). While a B/C ratio is important to understand *whether* a DSM plan screens positively, it is not appropriate when examining different strategic options for a specific program. For example, a program administrator may be considering two different options regarding incentive levels for a given program. Under option A, the utility would provide very low incentives, which would generate both low participation and high free ridership among participants. Under option B, the utility would provide high incentives, which would generate high participation but (arguably) cost the utility more money for every kWh saved. If the program manager used the simple PACT test (aka

Utility Cost Test), option A would show a much better B/C ratio, even though option B might maximize the net present value of the program.

Finally, I should note that beyond the choice of tests and their application context, users ought take care in determining appropriate inputs. Recent work, including by my firm and others, has found important errors in the inputs used to determine costs and benefits.

b) Please indicate the implications on DSM spending behind Mr. Dunsky's suspicion related to MH's screening practices.

To clarify, I did not point to a "suspicion" as much as addressed a variety of reasons that *may* explain Manitoba Hydro's DSM plan. Screening practices may or may not be among them.

If Manitoba Hydro were either placing too much emphasis on the RIM, or using a flawed version of the TRC, the impact could be to underestimate the net value of DSM options and, as a result, not pursue certain options. More importantly, if the tests are being used to optimize program designs, but NPV is not used as the metric, then there is a real risk that programs are being designed to produce minimal effect.

For example, I understand that the Levelized Utility Cost (LUC) is a critical consideration for Manitoba Hydro in screening DSM opportunities. The LUC effectively provides valuable information, and in many cases may be entirely appropriate to gage the value proposition of the plan as a whole (if the LUC is less than the avoided costs, which MH has determined as 8.5¢ for most end-uses, we know it is positive). However, if the LUC is used to compare program design *options*, then it will systematically bias toward weak programs that do not maximize utility or ratepayer interests.

The table below provides an example. Here the program manager is examining three different levels of incentives – 10%, 40%, or 70% – that she could offer to promote home energy retrofits. The retrofits themselves are expected to cost $5,000 on average, and generate 4,000 kWh of savings with an estimated useful life of 25 years. We assume an avoided cost of 8.5¢/kWh and a 6% discount rate to be consistent with Manitoba Hydro's stated inputs.

	Incentive		Participation		Utility Results			
Options	% of Cost	$/part.	Homes	% Free Riders	$ Cost	LUC	$ Benefit	NPV
A	10%	$500	100	60%	$50,000	$0.02	$173,854	$123,854
B	40%	$2,000	1000	20%	$2,000,000	$0.05	$3,477,073	$1,477,073
C	70%	$3,500	2000	10%	$7,000,000	$0.08	$7,823,414	$823,414

As we can see, if the program manager were asked to determine the appropriate option based on the LUC, she would choose option A, the cheapest one. This looks very good on a per-unit basis. However, the LUC ignores the # of units produced. As we can see, option B actually maximizes the utility's net present value, i.e. it is the least cost option for Manitoba Hydro's ratepayers. By

focusing on the LUC, the manager would have forfeited more than $1.3M in net benefits (not to mention 3.2 GWh of incremental annual savings).

It is worth reiterating that I am not privy to how Manitoba Hydro uses its screening tools, and am only speculating as to *possible* approaches that may help to explain the surprisingly low planned savings.

PUB/CAC & GAC 17 Reference: Page 36 DHPs

a) Please file the referenced study prepared by Mr. Dunsky's firm.

To clarify, we referred to an analysis conducted by my firm for purposes of this testimony. For purposes of this analysis, we used an algorithm calculation using the median Heating Seasonal Performance Factor (HSPF) of Mitsubishi Mr. Slim models. Nameplate HSPF value was adjusted to account for colder Canadian climate, and we further assumed that the heat pump would only supply heat to part of the home. In real life, mini-split systems can have multiple heads and/or multiple compressors to supply heat to a larger portion of the home (and savings can represent a larger share of heating loads). On the other hand, Winnipeg is colder than average Canadian cities, so we supplemented this initial estimate with other references.

A heat pump characterization study, conducted in Yukon and published in March 2010, has shown that cold climate heat pumps can supply a large portion of heating while maintaining good performance at low temperature. The study recommends that a heat pump be sized to supply 25% to 35% of the house heating load at -18 °C. A heat pump of this size will supply 60% to 75% of the annual heating load. As cold climate heat pumps maintain a COP of 2 and above at low temperatures , this would translate roughly into 30% to 40% savings on the annual heating load in the much colder climate of Whitehorse.

A heat pump energy efficiency reference guide, funded in part by Manitoba Hydro, also give an estimate of 30% to 45% savings from air source heat pumps over electric resistance heating for most of Manitoba including Winnipeg. This estimate is for all air source heat pumps and does not specifically refer to high efficiency, inverter-driven mini-split systems.

Finally, a very large pilot program launched in the Northwest US (a total of 16,000 units have now been installed in Idaho, Oregon, Montana and Washington states) confirmed ductless heat pump real-life performance with metering of a sample of installations (95 homes), including billing analysis and in-situ COP measurement, and with detailed laboratory testing . Results of the laboratory tests were compared to in-situ field monitoring data, and were found "surprisingly consistent".

The initial assumption was that the DHP would provide up to 60% of the space heat and result in a 30% to 40% reduction in space heating energy requirements. The actual fraction of house heated by the DHP was, on average, higher than excepted (67%), but lower (45%) for the coldest region. This is explained by the fact that the pilot's general approach was to market the system as a "displacement" technology— a technology that would partially offset the existing space heating. The systems were thought to be optimized with a single outdoor compressor and one or two

(a) Mr. Dunsky's comments largely relate to energy-specific DSM (GW.h saved). Does Mr. Dunsky view there to also be a role for expanded capacity-specific DSM (MW of peak saved) to provide system relief under key periods of supply constraint?

Yes. While my testimony was focused primarily on energy savings, capacity savings can also provide economic value. To this end, I note that certain energy efficiency measures provide more capacity savings than others. Moreover, non-efficiency related opportunities also exist, whether they involve thermal storage, demand response (e.g. through time of use rates), direct load control, curtailable power options or others. My firm recently completed a demand response potential study for one Canadian client, and is currently working with another utility client to develop a capacity-focused, integrated energy efficiency plan.

MIPUG – CAC & GAC 4 **PROGRAM TESTS**

(a) At page 33, Mr. Dunsky argues that Manitoba Hydro focuses on the wrong program screening tests (e.g., RIM, TRC). Does Mr. Dunsky agree with Hydro's description and specific arithmetic behind the calculation of each test as set out at Appendix F of the 2011 Power Smart Plan (Appendix 7.1).

TRC description: "*...to determine whether the benefits that are associated with an energy efficiency program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs*"

This describes the original intent of the TRC perfectly well. However, in practice the test does not achieve this goal, primarily because it is commonly fails to account for very significant customer benefits. For example, customers invest in home insulation and weatherization partly because of the energy savings, and partly because they seek to improve their comfort and/or reduce health issues. Yet the TRC only accounts for the former. Similarly, a customer with electric baseboard heat may seek to install a ductless heat pump in part to save energy, and in part to obtain cooling in summer months. Yet the TRC typically does not account for the cooling benefit to the participant, but *does* account for cooling as a cost (it slightly reduces net energy savings). To address this problem, the "*'Non-priced' benefits enjoyed by participants (improved comfort, improved heath)*", currently included in the Societal Cost test, should rather be included in the TRC test, keeping in mind that the TRC is the sum of participant and non-participant perspectives.

For these reasons, the TRC is increasingly being modified (substantively – e.g. in B.C.) or replaced.

Arithmetic: I agree with most of the arithmetic to the extent that it is limited to a very general algorithm. Behind the algorithm is much more arithmetic that may or may not be appropriate. However, I do note that the individual tests are meant to be expressed in a variety of ways – in B/C ratios, net present value (NPV), or unit costs (¢/kWh). The choice of

how to express results matters deeply, and should be different depending on the purpose of the test. I note that the algorithms presented in Appendix 7.1 express only the B/C ratio, which is perfectly appropriate for certain decisions, but wholly inappropriate for others (see the discussion below).

(b) In regard to the Levelized Utility Cost (LUC), Mr. Dunsky does not comment on this test. This test is generally described as a measure of how much the utility is paying to secure each unit of energy (or capacity), on a comparable basis to other supply options (e.g., new generation). Is this not a critical primary test of where the utility is appropriately securing DSM as a supply option, versus spending excessively on limited results?

Allow me to begin with a clarification: the LUC is not and should never be considered a "test", because it does not compare costs to benefits. It is rather a cost metric.

As the question suggests, however, the LUC is a critically important metric, in that it subsequently allows us to compare costs (LUC = the unit cost) with benefits (e.g. avoided costs). The test that compares these is known as the Program Administrator Cost Test, or PACT (formerly known as the Utility Cost Test). The PACT is a simple and straightforward comparison of the utility's cost of saved energy vs. the utility's value of that saved energy (avoided costs). Please see my response to PUB/CAC & GAC 16(a).

It is important to note that the *way* in which utility costs and benefits are compared is as important as *what* is compared. In that sense, the PACT ratio (being LUC/ACs) may provide valuable information to determine whether an option is cost-effective, but the PACT NPV is needed to determine which among multiple options is preferable. Please see my response to PUB/CAC & GAC 16(b) – the "NPV" column in the table is in effect the NPV of the PACT test.

(c) To what extent do changes in the value of power on export markets, or changes in the expected cost of alternative resources (e.g., new generation) drive changes in the targeted level of DSM investment under the tests proposed by Mr. Dunsky (e.g., GW.h saved/GW.h sold)?

DSM should be pursued for one or both of two reasons: when its cost is less than its benefits, or to meet specific policy objectives.

Setting aside the latter, the benefits of DSM are determined largely by the alternatives it can displace or defer (or, in some cases, the price it can fetch on export markets). As such, changes to these values can, in theory, be very important factors.

In practice, I note that Manitoba Hydro's current DSM Plan anticipates saving energy at a cost of 1.8¢/kWh, against a benefit in the range of 8.5¢/kWh. In other words, the margin of

net benefit is so large that the change in benefits would have to be dramatic to significantly impact the amount of DSM that should be targeted. Even if the cost of saved energy were to double in order to achieve a much higher savings ratio, and even if the value of saved energy were to drop by half, that much higher savings scenario would still be the cheaper option.

loads grow fastest and DSM is most valuable. Similarly, *DSM program* savings may be at risk when governments adopt tighter codes and standards; in this case, overall energy efficiency improves for the very reason that program performance may be hindered.

PUB/CAC & GAC 14 Reference: Page 32, DSM Impact on Ratepayers

"As a reduction in DSM spending invariably – mathematically in fact – involves increases in net costs for the province's ratepayers as a whole, and further deprives consumers in the short-run of a solution to offset the effect of such increases."

a) Please provide a schedule illustrating how a reduction in DSM spending will increase net costs to ratepayers.

Using the residential sector as an example, Manitoba Hydro currently spends 1.5¢ for every kWh saved (lifetime levelized).[2] Each kWh thus saved helps Manitoba Hydro to avoid costs, according to the utility, of 8.5¢/kWh.[3] Therefore each kWh saved under Manitoba Hydro's current plan results in 7¢ of net benefit.[4]

Put differently, if Manitoba Hydro were to *not* spend the 1.5¢ it plans on spending to help residential customers reduce their bills, residential ratepayers would have to pay 8.5¢/kWh instead, as the cost necessary to either expedite construction of the next power plant (and associated T&D costs), or make up for lost export revenue. **Put in the aggregate, if Manitoba Hydro *did not* spend the $5.2 million it plans on spending in the current fiscal year, ratepayers would instead have to pay $29.5 million to support the utility's additional costs.**

b) Please provide a schedule demonstrating how a reduction in DSM spending equivalent to 100 GWh of energy savings in one year will increase net costs to ratepayers.

Using the same approach as above, let us take Manitoba Hydro's current plan. In Appendix A, we see that incremental savings of nearly that amount (92.8 GWh) are expected from the plan's first year (2011-12). To achieve those savings, Manitoba Hydro budgeted $19.9 million in that same year.[5] On page 14 of the plan, we see that the total levelized cost of kWhs produced in this plan is 1.8¢/kWh (note: this covers all sectors, whereas the example I gave previously was specific to residential). From the utility's answers to certain IRs, we understand that the avoided cost is close to 8.5¢/kWh, or a ratio of 5:1.

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[2] Manitoba Hydro, 2011 Power Smart Plan, October 2011, page 14.

[3] Manitoba Hydro, response to CAC-GAC/MH I-4(b).

[4] This comparison includes a minor simplification, in that the stated avoided costs are for a kWh levelized over a 30-yr timeframe, which may be different from the average life of residential measures. However I would not anticipate that a closer matching would significantly alter the comparison.

[5] Manitoba Hydro, 2011 Power Smart Plan, October 2011, Appendix A.

Assuming that the levelized cost of savings applies to savings generated in year 1, we can surmise that, had Manitoba Hydro eliminated its DSM budget for the first year of the plan, the net result would be:

	Unit Cost	Absolute Cost
DSM Spending (reduction)	(1.8 ¢/kWh)	($19.9 M)
Utility-wide Cost (lost opportunity cost)	8.5 ¢/kWh	$94.0 M
Net Cost to Ratepayers of reducing DSM spending	**6.7 ¢/kWh**	**$74.1 M**

PUB/CAC & GAC 15 Reference: Page 33 Economic Screening RIM

a) Is MH's financial well-being best served by increasing domestic electricity consumption which provides higher revenue rates than exports?

If choosing between selling to export or to domestic customers, and if ignoring the interests of said customers, then yes MH's financial interest is best served as described.

If choosing between increasing sales – to export *or* domestically – and not increasing sales, the answer depends on the associated costs and revenues. In the current case, Manitoba Hydro's long-run marginal cost of increasing sales to domestic customers appears to be 8.5¢/kWh[6], while the current plan's cost to reduce sales growth is pegged at 1.8¢/kWh. Arguably, this suggests that the long-run financial well-being of MH is best served by efforts at reducing sales growth. If accounting for lost revenues, then all depends on which customer categories are involved: residential at 6.9¢/kWh, general service at between 2.8-3.3¢ (last block, not counting demand changes, depending on customer size).

In practice, the financial impact of any scenario depends on how rates adjust to costs.

Of course, the financial well-being of MH's domestic customers - whose bills would increase to ensure the greater domestic sales - is another matter altogether.

b) Please comment on the MH's marginal cost employed in RIM, TRC and other tests.

My scope of work did not include an assessment of Manitoba Hydro's marginal cost methodology.

[6] Manitoba Hydro, response to CAC-GAC/MH I-4(b). Note that this applies to residential and most commercial/institutional customers; the cost to transmission-linked large industrial customers may be somewhat lower.

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[6] Manitoba Hydro, response to CAC-GAC/MH I-4(b). Note that this applies to residential and most commercial/institutional customers; the cost to transmission-linked large industrial customers may be somewhat lower.

b) Please indicate the source of the information that supports the claim that there are 13,750 new electrically heated homes built in Manitoba annually.

The correct value should read "approximately 2,750". This is from Manitoba Hydro's response to CAC-GAC/MH II-4(a), in which 13,750 was provided as the value for new housing starts that use electric heat. I failed to notice that this value was not annual but covered the five-year period from 2005-2009.

PUB/CAC & GAC 18 Reference: Dunsky Report Page 38

Please indicate to what extent increased DSM spending could defer the current need for new Generation in MH's current plans.

To answer this question, we examine two scenarios:

In the first scenario, program-related savings are increased such that, when combined with MH's anticipated *other* savings (codes, standards, self-gen), total savings achieve and maintain a 1% savings/sales ratio. This implies that Manitoba Hydro's programs alone achieve a ratio of approximately 0.6% every year on average.

In the second scenario, program savings are increased such that, combined with other savings sources, the total achieves 1.5%/year on average. For comparison purposes, we note that over the next ten years (2012-2021), B.C.'s *average* equivalent total savings ratio is 1.7%.

Under the 1% scenario (0.6% from programs), additional savings of 637 GWh are generated by the time the Keeyask project is supposed to be commissioned (in-service date 2019/20). This allows Manitoba Hydro to defer this project by three years (assuming that exports do not change). The Conawapa project, scheduled to be commissioned in 2024/25, would be deferred by 7 years (to 2031/32). I note that this analysis is based on energy needs; I have not had the time to conduct the analysis of capacity needs needed to confirm these values.

Under the 1.5% scenario, additional savings of 1,385 GWh/yr by 2019/20 would allow for Keeyask to be deferred by 12 years (to 2031/32). I did not calculate the expected in-service date for the Conawapa project under this scenario as this would be too speculative.

On the cost side, the reader will recall (see Fig. 16 of my testimony) that Manitoba Hydro's current savings cost some 28¢/kWh$_{1st\text{-}YR}$ (this is not to be confused with levelized lifetime savings). This is slightly below the costs incurred by BC Hydro, Efficiency Nova Scotia, and Vermont (30¢/kWh). Assuming that Manitoba Hydro's unit costs increase to 30¢/kWh, Manitoba Hydro would have to spend an additional $191 million (cumulative) by 2019/20 for the 1% scenario, or $416 million (cumulative) for the 1.5% scenario. Of course, other DSM options like codes & standards, and rate structures, are a lot cheaper from the utility's point of view, and would decrease the amount of additional spending required.

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	Business as usual	**1% DSM target***	**1.5% DSM target***
Additional savings by 2019/20	---	637 GWh	1,385 GWh
Additional spending by 2019/20	---	$191 M or less	$416 M or less
Keeyask in-service date	2019/20	**2022/23**	**2031/32**
Conawapa in-service date	2024/25	**2031/32**	**?**

* *Includes all of Manitoba Hydro's anticipated savings from codes, standards, and self-generation. The implied MH program-related savings ratios are 0.6% and 1.1%/year, the latter being approximately the same as BC Hydro's.*

The incremental cost is annotated with "or less" because the cost provided assumes that the full increase in savings is derived from increased program-related activity. For example, under the *fully-inclusive* 1.5% target, we assume that program savings increase to 1.1%/yr on average (similar to BC Hydro's latest plans), the remainder involving the same level of *non-program* savings (from codes, standards and self-generation) as currently anticipated by MH. Should the non-program portion of savings increase – e.g. from the introduction of rate structure strategies – then the program-related costs would likely be lower to achieve the same overall savings goal.

2010 Savings Ratios (GWh savings / GWh sold)		References
Vermont	1.98%	2010 Electric Retail Sales: Sales_annual.xls (spreadsheet from US EIA). 2010 Electric Energy Savings: Efficiency Vermont 2011 Savings claim (April 1, 2012) - Table 1 (p. 2)
California	1.79%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Connecticut	1.39%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Minnesota	1.14%	2010 Electric Retail Sales: Xcel Energy 2010/2011/2012 Triennal Plan - Minnesota Electric and Natural Gas Conservation Improvement, p. 4 (total adjusted -retail- sales). 2010 Electric Energy Savings: Xcel Energy 2010/2011/2012 Triennal Plan - Minnesota Electric and Natural Gas Conservation Improvement, p. 16.
Hawaii	1.15%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Oregon	1.11%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Massachusetts	1.05%	2010 Electric Retail Sales: Sales_annual.xls (spreadsheet from US EIA). 2010 Electric Energy Savings: The 2011 Report of the Massachusetts Energy Efficiency Advisory Council (sept. 2012), p. 1
Nevada	1.05%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Rhode Island	1.04%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Idaho	0.98%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Arizona	0.98%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Iowa	0.98%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Montana	0.85%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
New York	0.84%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Washington	0.84%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
British Columbia	0.84%	2010 Electric Retail Sales: 2012 Integrated Resource Plan - Appendix 2A, p.112 "Total Domestic Sales". 2010 Electric savings: Excel spreadsheet "BC Hydro DSM Forecasts", table 1 (from Amended F12/F14 RRA)
Wisconsin	0.77%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Nova Scotia	0.83%	2010 Electric Retail Sales : EnSC 2013-2015 DSM Filing (E-EnSC-R-12), pp. 18, and 22/45 (excl. Extra-large industrial clients). 2010 Electric Energy Savings: Nova Scotia Power 2013 General Rate Application, DE-03, p. 43/159
Maine	0.73%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Michigan	0.72%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Utah	0.65%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
New Hampshire	0.62%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Colorado	0.59%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Maryland	0.48%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Ohio	0.47%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Illinois	0.46%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Manitoba	0.43%	2010 Electric retail sales: 2011 Power Smart Plan, appendix 7.1 (appendix 8-3). 2010 Electric Energy Savings: 2011 Electric Load Forecast, appendix 8-1
New Jersey	0.40%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31)
Quebec	0.55%	Dunsky Energy Consulting - Internal data sources
New Mexico	0.38%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
North Carolina	0.38%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
District of Columbia	0.35%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Missouri	0.34%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Nebraska	0.27%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Oklahoma	0.23%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Pennsylvania	0.23%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
South Dakota	0.22%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
South Carolina	0.21%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Texas	0.19%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Florida	0.18%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Delaware	0.15%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Kentucky	0.15%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Tennessee	0.14%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Wyoming	0.14%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Arkansas	0.11%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Indiana	0.07%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Kansas	0.07%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Alabama	0.05%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Mississippi	0.05%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Georgia	0.04%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Alaska	0.02%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
North Dakota	0.01%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Louisiana	0.00%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
Virginia	0.00%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).
West Virginia	0.00%	ACEEE, The 2012 State Energy Efficiency Scorecard, Table 12 (p. 31).

focusing on the LUC, the manager would have forfeited more than $1.3M in net benefits (not to mention 3.2 GWh of incremental annual savings).

It is worth reiterating that I am not privy to how Manitoba Hydro uses its screening tools, and am only speculating as to *possible* approaches that may help to explain the surprisingly low planned savings.

PUB/CAC & GAC 17 Reference: Page 36 DHPs

a) Please file the referenced study prepared by Mr. Dunsky's firm.

To clarify, we referred to an analysis conducted by my firm for purposes of this testimony. For purposes of this analysis, we used an algorithm calculation using the median Heating Seasonal Performance Factor (HSPF) of Mitsubishi Mr. Slim models. Nameplate HSPF value was adjusted to account for colder Canadian climate, and we further assumed that the heat pump would only supply heat to part of the home. In real life, mini-split systems can have multiple heads and/or multiple compressors to supply heat to a larger portion of the home (and savings can represent a larger share of heating loads). On the other hand, Winnipeg is colder than average Canadian cities, so we supplemented this initial estimate with other references.

A heat pump characterization study, conducted in Yukon and published in March 2010, has shown that cold climate heat pumps can supply a large portion of heating while maintaining good performance at low temperature. The study recommends that a heat pump be sized to supply 25% to 35% of the house heating load at -18 °C. A heat pump of this size will supply 60% to 75% of the annual heating load. As cold climate heat pumps maintain a COP of 2 and above at low temperatures , this would translate roughly into 30% to 40% savings on the annual heating load in the much colder climate of Whitehorse.

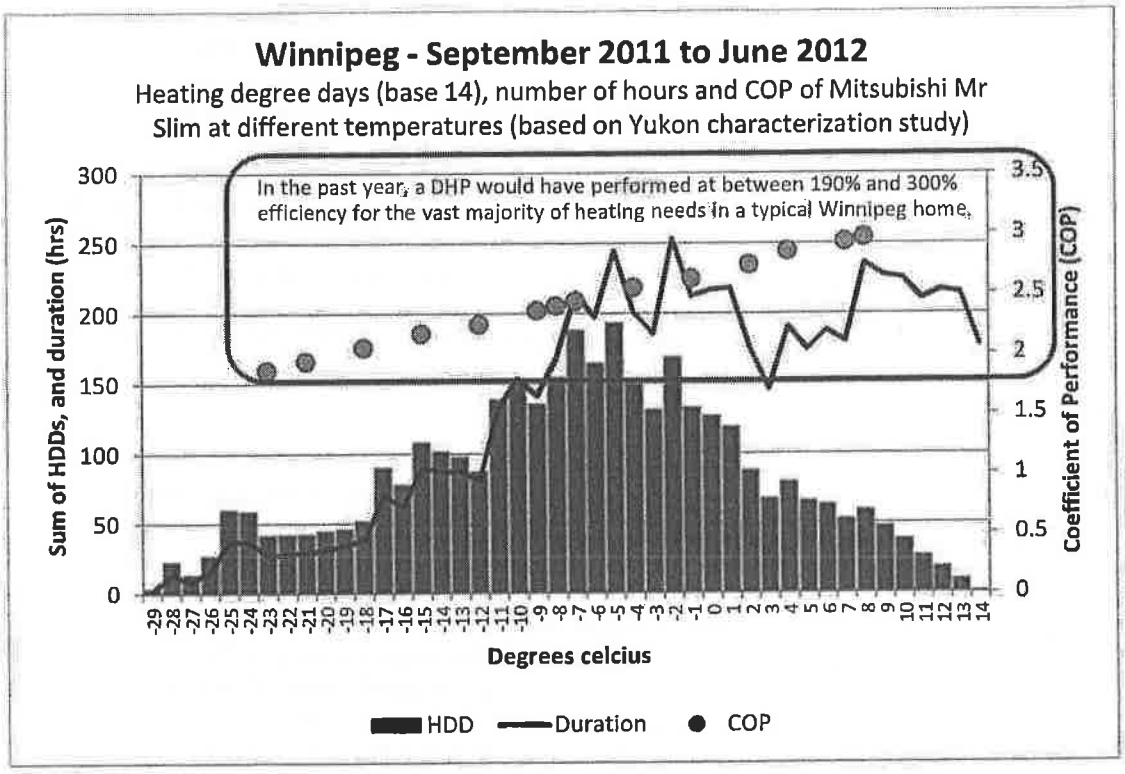
A heat pump energy efficiency reference guide, funded in part by Manitoba Hydro, also give an estimate of 30% to 45% savings from air source heat pumps over electric resistance heating for most of Manitoba including Winnipeg. This estimate is for all air source heat pumps and does not specifically refer to high efficiency, inverter-driven mini-split systems.

Finally, a very large pilot program launched in the Northwest US (a total of 16,000 units have now been installed in Idaho, Oregon, Montana and Washington states) confirmed ductless heat pump real-life performance with metering of a sample of installations (95 homes), including billing analysis and in-situ COP measurement, and with detailed laboratory testing . Results of the laboratory tests were compared to in-situ field monitoring data, and were found "surprisingly consistent".

The initial assumption was that the DHP would provide up to 60% of the space heat and result in a 30% to 40% reduction in space heating energy requirements. The actual fraction of house heated by the DHP was, on average, higher than excepted (67%), but lower (45%) for the coldest region. This is explained by the fact that the pilot's general approach was to market the system as a "displacement" technology— a technology that would partially offset the existing space heating. The systems were thought to be optimized with a single outdoor compressor and one or two

indoor air handlers. It is also important to note that systems with more than two indoor units or one outdoor unit that actually entered the pilot program were not metered during the subsequent impact analysis. The "one head – one compressor" configuration represents a relatively low-cost way to supply the needs of a major portion of the heating load, but is less efficient in colder climate. In colder regions, the effect of multiple heads is to offset the load more effectively and reduce the time that the electric resistance operates (the effect of multiple heads is much smaller in warmer regions). Optimizing the configuration for Manitoba's climate would necessarily improve this result.

As can be seen on the following graph, the Mitsubishi Mr Slim maintains a COP value above 2 up to -18 °C, meaning the heat provided at this low temperature is still twice as efficient as electric resistance heating (or takes half the quantity of kWh for the same output). Temperatures colder than -18 °C represent a very small proportion of the Winnipeg winter, both in terms of duration and heating requirements (HDDs). Heating needs peak at about 5 °C, where the COP is near 2.5.



Finally, my firm conducted an analysis for the present IR round using the Hot2000 modeling software and a single-family detached house located in Winnipeg with an annual heating load of 60 GJ. Electric savings due to the installation of a DHP represented 36% of the heating load. This result is again consistent with our earlier estimate, as with the literature review. Please refer to MH/CAC/GAC (Dunsky)-3 for more information.

b) Please indicate the source of the information that supports the claim that there are 13,750 new electrically heated homes built in Manitoba annually.

The correct value should read "approximately 2,750". This is from Manitoba Hydro's response to CAC-GAC/MH II-4(a), in which 13,750 was provided as the value for new housing starts that use electric heat. I failed to notice that this value was not annual but covered the five-year period from 2005-2009.

PUB/CAC & GAC 18 Reference: Dunsky Report Page 38

Please indicate to what extent increased DSM spending could defer the current need for new Generation in MH's current plans.

To answer this question, we examine two scenarios:

In the first scenario, program-related savings are increased such that, when combined with MH's anticipated *other* savings (codes, standards, self-gen), total savings achieve and maintain a 1% savings/sales ratio. This implies that Manitoba Hydro's programs alone achieve a ratio of approximately 0.6% every year on average.

In the second scenario, program savings are increased such that, combined with other savings sources, the total achieves 1.5%/year on average. For comparison purposes, we note that over the next ten years (2012-2021), B.C.'s *average* equivalent total savings ratio is 1.7%.

Under the 1% scenario (0.6% from programs), additional savings of 637 GWh are generated by the time the Keeyask project is supposed to be commissioned (in-service date 2019/20). This allows Manitoba Hydro to defer this project by three years (assuming that exports do not change). The Conawapa project, scheduled to be commissioned in 2024/25, would be deferred by 7 years (to 2031/32). I note that this analysis is based on energy needs; I have not had the time to conduct the analysis of capacity needs needed to confirm these values.

Under the 1.5% scenario, additional savings of 1,385 GWh/yr by 2019/20 would allow for Keeyask to be deferred by 12 years (to 2031/32). I did not calculate the expected in-service date for the Conawapa project under this scenario as this would be too speculative.

On the cost side, the reader will recall (see Fig. 16 of my testimony) that Manitoba Hydro's current savings cost some 28¢/kWh$_{1st\text{-}YR}$ (this is not to be confused with levelized lifetime savings). This is slightly below the costs incurred by BC Hydro, Efficiency Nova Scotia, and Vermont (30¢/kWh). Assuming that Manitoba Hydro's unit costs increase to 30¢/kWh, Manitoba Hydro would have to spend an additional $191 million (cumulative) by 2019/20 for the 1% scenario, or $416 million (cumulative) for the 1.5% scenario. Of course, other DSM options like codes & standards, and rate structures, are a lot cheaper from the utility's point of view, and would decrease the amount of additional spending required.

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At a typical yield of $0.30/kwh (first year)[1], the annual budgetary requirement for Manitoba Hydro would be about $65 million.

I have not undertaken a complete assessment of Manitoba Hydro's planned portfolio of programs, though I identified in my testimony some examples of opportunities that do not seem to be targeted. Broadly speaking, each program would need to be revisited with a view to maximizing both depth of savings and participation rates.

PUB/CAC & GAC 2 Reference: Dunsky Rpt Page 6

a) Please provide a comparison between the savings over sales versus share of forecast growth approaches for MH

See response to (b) below.

b) Please explain what factors have led to the share of forecast growth not being used as a metric.

There are two primary factors:

First, savings / sales has evolved to become the industry standard benchmarking metric.

Second, the alternative "share of forecast growth" metric would have been uniquely unfair to Manitoba Hydro in the current North American economic context. As economic growth – and with it demand growth – has temporary slowed or halted in many US states, this indicator would likely have pointed to much higher ratios for states with the most affected economies, compared with Manitoba that has largely weathered the storm. The resulting values for these US states would have appeared artificially impressive, but would have been the result of a temporary economic anomaly.

c) Given MH's planned investments in new Generation and Transmission please explain which metric is most appropriate in measuring DSM efforts.

It depends on the purpose of the metric. If the purpose is to compare DSM goals and performance against other regions, the savings/sales metric is more appropriate for the reasons noted above. If the purpose is to set internal targets, both can be of value. For example, Manitoba might wish to adopt a target or requirement for DSM to cover X% of projected load growth; the resulting planned savings could then be benchmarked against other regions using a % of sales metric.

PUB/CAC & GAC 3 Reference: Dunsky Report Page 8

Please describe how rate structure changes have been utilized in other jurisdictions and comment on the applicability of these rate structures in the context of MH. Provide specific examples.

[1] Manitoba Hydro's current planned cost is $0.28/kWh (first year).

BC Hydro recently adopted a relatively aggressive revamping of its rate structures to encourage energy efficiency, and others are considering similar changes. Simply put, the rate structures include two tiers: a less expensive rate for the first tier of consumption, and a more expensive rate for the second tier.

For example, for residential customers, the utility adopted a "Conservation Rate" structure by which the first block of energy is sold at 6.8¢/kWh, and the second at 10.2¢/kWh. For business users (large and medium), a more complex structure leads to the same results: a lower-priced first block of energy (determined as 80% of the client's monthly rolling three-year historical average consumption) is less expensive, followed by a higher-priced second block (to achieve this result, a system of credits and charges is used). The higher rate is based on the long-run marginal cost of supply. Some exceptions apply.

In other regions, time-of-use (TOU) rates are increasingly adopted. This is the case in Ontario and Nova Scotia, and is likely to be adopted elsewhere in the coming years. In Ontario, customers of regulated entities can choose between tiered rates (as per B.C. above) and TOU rates. In Nova Scotia, a voluntary TOU rate is available to residential customers through which power rates vary between 6.5¢/kWh and 16.4¢/kWh. The utility also offers real-time pricing based on short-run marginal costs to its largest customers.

I have not examined Manitoba Hydro's rate and load structures, and therefore cannot recommend a given approach at this time. However, I am not aware of any reason for which the BC model could not be adapted for Manitoba Hydro. Doing so can certainly help to align rate structures with cost structures and/or with broader policy goals.

PUB/CAC & GAC 4 Reference: Page 10 Figure 4

a) Mr. Dunsky has indicated a continued decline in MH's Saving Ratios, relative to other jurisdictions. Please provide an updated comparison showing the Savings Ratio changes reflecting the evolving plans for Minnesota, Massachusetts, BC, Nova Scotia and Vermont relative to MH.

Please see the table below. Note that four of the cohort plans do not extend to 2020 and beyond. These values are also provided in Figure 5 (page 13) of my testimony.

	2010	2015	2020	2025
Minnesota	1.1%	1.4%		
Massachusetts	1.3%	2.6%		
British Columbia	0.8%	1.0%	1.1%	
Nova Scotia	0.8%	1.3%		
Vermont	2.0%	2.1%*		
Manitoba	0.4%	0.3%	0.2%	0.1%

** Data is for 2014.*

Manitoba Hydro 2013 & 2014 GRA

Information Requests of the Public Utilities Board

November 22, 2012

PUB/CAC & GAC 12 Reference: Page 27. Plans vs. Real Savings

a) Please indicate what impact if any does MH's self reporting have on its DSM efforts.

Without independent evaluations, the extent to which Manitoba Hydro's self-reporting may or may not be accurate would be speculative at best. I do note that MH's "2010-2011 Power Smart Annual Review", while providing summary results, provides no indication as to how free ridership and other net-to-gross factors were determined (billing analysis, participant and non-participant surveys, measurement and verification activities, etc.), nor does it provide any of that information (these would normally be provided, on either a program or measure-level basis, in typical independent evaluations, along with a complete description of the methodology).

In my experience, independent evaluations can be extremely valuable, not only in determining actual savings, but as or more importantly, in identifying program strengths *and weaknesses* with a view to continuously improving performance by modifying program strategies accordingly.

b) How effective is the reputational incentive to succeed in DSM achievements.

Reputational incentives *may* be effective, but the degree to which they are can vary tremendously from case to case. On the other hand, legally binding requirements and financial incentives/penalties are almost always very effective.

c) Please indicate how MH's reporting and evaluation should change and explain why.

In preparing my testimony, I did not seek to examine MH's internal evaluation processes in detail. As a result, I would not want to comment on specific evaluation methodologies. However, I can certainly comment on the process.

There are many ways to approach evaluation, but they should all begin with an evaluation plan. The plan should specify which programs should undergo which types of evaluation (e.g. process, impact), at which times, and should also specify the nature of the information that should be reported. For example, the evaluation plan may be spread over 3 years; within those 3 years, some programs would undergo annual impact evaluations, while others (where impact evaluations are deemed less important) might be evaluated only once in that timeframe. The board could specify that reported results should include net and gross savings, a delineation of the factors that led from gross to net (e.g. free ridership, spillover, market effects), areas of uncertainty, costs by major category (e.g. incentives, customer support, administration), benefit/cost results, and other important variables. In all cases, the full evaluation report with detailed results and methodological descriptions should be provided as an appendix.

The board's role in the process should be an equally important consideration. For example, in some regions the utility is allowed to hire the evaluators, oversee the work, and merely submit the results to the regulator. In other regions, a committee comprised of representatives of the utility, the regulator and stakeholders oversees the scope of work and the resulting RFP, selects the evaluators, and jointly determines the information to be reported back. In another model, the

regulator approves the evaluation plan, allows the utility to hire the evaluator and report their findings, but then hires an expert to independently review the evaluator's work. It is important to keep in mind that the independence of the evaluator is critical to the value of the process. From that perspective, I would urge the board to consider the two latter options.

PUB/CAC & GAC 13 Reference: Page 28 DSM Risk

a) Please explain how MH's DSM could become a dispatchable product [i.e. biddable into the MISO market]

This falls outside the scope of my testimony.

b) Please explain how DSM has less risk than:

i. New CCCT natural gas

Assuming the question refers to the option of Manitoba Hydro building its own CCCT plant, the major risks are fourfold: (1) construction cost overruns (cost risk), (2) construction schedule delays (cost and availability risk), (3) gas price forecast accuracy (cost risk), and (4) future environmental regulations related to greenhouse gas or other air emissions (cost risk). Each of these risks can be significant.

Were the CCCT to be built instead by a third party under a long-term PPA, it would depend on the terms of the contract. For example, in many PPA contracts, fuel price risk is passed on to the purchasing utility, but construction cost overruns or delays may be assumed by the IPP and built into their costing.

ii. New Hydro

The major risks associated with new hydro are the same as (1) and (2) above. In addition, if the hydro is large-scale and therefore involves a long planning and construction lead time, there is a very important risk related to (3) the accuracy of demand forecasts (for example, if in the intervening years demand grows at a slower pace than expected, the value of the asset upon coming into service may be severely depleted for many years). This should be considered a substantial cost risk. A fourth risk relates to (4) the accuracy of rainfall forecast models, especially in the context of significant climactic changes currently underway (this is both an availability and a cost risk). A final risk relates to (5) the possibility of heightened environmental regulations in the future (e.g related to fish and wildlife protection).

In contrast, the risks associated with energy efficiency are far smaller, primarily for the reasons noted in my testimony: program offerings can be ramped up or down – as well as shifted between measures, programs and sectors – as needed to ensure performance objectives are met. Furthermore, the most important exogenous factors tend to be *positive* risk factors for DSM. For example, savings opportunities are greater when economic activity is strong, which is also when