ONTARIO ENERGY BOARD

EB-2016-0296
EB-2016-0300
EB-2016-0330

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an applications for approval of the cost consequences of cap and trade compliance plans

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ENVIRONMENTAL DEFENCE COMPENDIUM

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Table 1: 2016 TRC-Plus and PAC Analysis and Ratios

	2016 Total Resource Acquisition & Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Multi-Year TRC & PACT Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Resource Acquisition & Low Income	**27,582**	**$217,059,376**	**$59,697,663**	**$27,580,805**	**$8,652,012**	**$9,532,442**	**$77,882,117**	**$139,177,259**	**2.79**	**$45,765,260**	**$171,294,117**	**4.74**
Resource Acquisition	25,164	$199,710,338	$51,329,613	$20,327,865	$6,869,861	$7,095,334	$65,294,808	$134,415,530	3.06	$34,293,059	$165,417,278	5.82
Low Income	2,418	$17,349,039	$8,368,050	$7,252,941	$1,782,152	$2,437,108	$12,587,310	$4,761,729	1.38	$11,472,200	$5,876,839	1.51

	2016 Resource Acquisition						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Resource Acquisition TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Large Customers												
Large Custom	727	$118,590,505	$33,514,579	$4,961,668	$1,213,962	$0	$34,728,541	$83,861,964	3.41	$6,175,630	$112,414,875	19.20
Large Prescriptive	4,165	$13,924,742	$624,575	$686,971	$541,225	$0	$1,165,800	$12,758,942	11.94	$1,228,195	$12,696,546	11.34
Small Customers												
Small Custom	112	$7,208,617	$5,145,084	$442,932	$402,102	$0	$5,547,187	$1,661,430	1.30	$845,034	$6,363,583	8.53
Small Prescriptive	1,959	$15,558,287	$293,721	$767,561	$201,196	$0	$494,916	$15,063,371	31.44	$968,757	$14,589,531	16.06
Small DI	1,679	$13,335,675	$251,760	$3,647,650	$1,307,771	$0	$1,559,531	$11,776,143	8.55	$4,955,421	$8,380,254	2.69
Residential Adaptive Thermostats	9,014	$5,373,101	$612,959	$676,058	$200,313	$0	$813,272	$4,559,828	6.61	$876,371	$4,496,729	6.13
Residential CER	7,508	$25,719,411	$10,886,935	$9,145,025	$3,003,292	$0	$13,890,227	$11,829,184	1.85	$12,148,317	$13,571,094	2.12
RA Overall TRC	**25,164**	**$199,710,338**	**$51,329,613**	**$20,327,865**	**$6,869,861**	**$7,095,334**	**$65,294,808**	**$134,415,530**	**3.06**	**$34,293,059**	**$165,417,278**	**5.82**

	2016 Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Low Income TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Multi-Family Homes - Part 3	217	$10,953,060	$4,457,993	$2,426,481	$852,547	$0	$5,310,541	$5,642,519	2.06	$3,279,028	$7,674,032	3.34
Single Family Homes - Part 9	2,201	$6,395,979	$3,910,056	$4,826,460	$929,604	$0	$4,839,661	$1,556,318	1.32	$5,756,064	$639,915	1.11
LI Overall TRC	**2,418**	**$17,349,039**	**$8,368,050**	**$7,252,941**	**$1,782,152**	**$2,437,108**	**$12,587,310**	**$4,761,729**	**1.38**	**$11,472,200**	**$5,876,839**	**1.51**

Table 2: 2017 TRC-Plus and PAC Analysis and Ratios

	2017 Total Resource Acquisition & Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Multi-Year TRC & PACT Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Resource Acquisition & Low Income	**34,545**	**$234,889,018**	**$57,478,860**	**$32,010,199**	**$8,812,072**	**$9,966,611**	**$76,257,543**	**$158,631,475**	**3.08**	**$50,788,882**	**$184,100,136**	**4.62**
Resource Acquisition	32,007	$216,669,714	$48,688,389	$24,248,549	$6,915,601	$7,602,524	$63,206,514	$153,463,200	3.43	$38,766,674	$177,903,040	5.59
Low Income	2,538	$18,219,304	$8,790,471	$7,761,650	$1,896,471	$2,364,087	$13,051,029	$5,168,275	1.40	$12,022,208	$6,197,096	1.52

	2017 Resource Acquisition						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Resource Acquisition TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Large Customers												
Large Custom	723	$117,939,594	$33,330,627	$5,056,873	$1,237,255	$0	$34,567,882	$83,371,712	3.41	$6,294,128	$111,645,466	18.74
Large Prescriptive	4,142	$13,848,313	$621,147	$700,152	$551,610	$0	$1,172,757	$12,675,556	11.81	$1,251,762	$12,596,551	11.06
Small Customers												
Small Custom	113	$7,309,098	$5,216,802	$452,358	$410,659	$0	$5,627,461	$1,681,637	1.30	$863,017	$6,446,082	8.47
Small Prescriptive	1,986	$15,775,154	$297,815	$783,895	$205,477	$0	$503,292	$15,271,862	31.34	$989,372	$14,785,783	15.94
Small DI	1,702	$13,521,561	$255,270	$3,725,272	$1,335,600	$0	$1,590,870	$11,930,691	8.50	$5,060,872	$8,460,689	2.67
Residential Adaptive Thermostats	18,000	$10,729,388	$1,224,000	$1,350,000	$175,000	$0	$1,399,000	$9,330,388	7.67	$1,525,000	$9,204,388	7.04
Residential CER	5,340	$34,254,955	$7,742,729	$12,180,000	$3,000,000	$0	$10,742,729	$23,512,226	3.19	$15,180,000	$19,074,955	2.26
RA Overall TRC	**32,007**	**$216,669,714**	**$48,688,389**	**$24,248,549**	**$6,915,601**	**$7,602,524**	**$63,206,514**	**$153,463,200**	**3.43**	**$38,766,674**	**$177,903,040**	**5.59**

	2017 Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Low Income TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Multi-Family Homes - Part 3	228	$11,507,228	$4,686,633	$2,529,410	$888,711	$0	$5,575,345	$5,931,883	2.06	$3,418,121	$8,089,107	3.37
Single Family Homes - Part 9	2,310	$6,712,076	$4,103,837	$5,232,240	$1,007,760	$0	$5,111,597	$1,600,479	1.31	$6,240,000	$472,076	1.08
LI Overall TRC	**2,538**	**$18,219,304**	**$8,790,471**	**$7,761,650**	**$1,896,471**	**$2,364,087**	**$13,051,029**	**$5,168,275**	**1.40**	**$12,022,208**	**$6,197,096**	**1.52**

Witnesses: R. Idenouye
S. Moffat
F. Oliver Glasford
B. Ott
R. Sigurdson

Table 3: 2018 TRC-Plus and PAC Analysis and Ratios

	2018 Total Resource Acquisition & Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Multi-Year TRC & PACT Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Resource Acquisition & Low Income	**48,555**	**$251,201,450**	**$66,489,040**	**$36,353,379**	**$8,414,927**	**$10,334,976**	**$85,238,943**	**$165,962,507**	**2.95**	**$55,103,282**	**$196,098,168**	**4.56**
Resource Acquisition	45,988	$231,543,744	$57,102,463	$28,142,333	$6,385,477	$7,985,813	$71,473,753	$160,069,991	3.24	$42,513,623	$189,030,121	5.45
Low Income	2,567	$19,657,706	$9,386,577	$8,211,046	$2,029,450	$2,349,163	$13,765,190	$5,892,516	1.43	$12,589,659	$7,068,047	1.56

	2018 Resource Acquisition						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Resource Acquisition TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Large Customers												
Large Custom	739	$120,544,190	$34,066,705	$5,262,555	$1,287,579	$0	$35,354,284	$85,189,905	3.41	$6,550,134	$113,994,056	18.40
Large Prescriptive	4,234	$14,154,141	$634,864	$728,630	$574,046	$0	$1,208,910	$12,945,231	11.71	$1,302,676	$12,851,465	10.87
Small Customers												
Small Custom	106	$6,872,172	$4,904,950	$425,317	$386,111	$0	$5,291,060	$1,581,112	1.30	$811,427	$6,060,745	8.47
Small Prescriptive	1,867	$14,832,141	$280,012	$737,035	$193,194	$0	$473,206	$14,358,935	31.34	$930,229	$13,901,912	15.94
Small DI	1,600	$12,713,263	$240,010	$3,502,583	$1,255,761	$0	$1,495,771	$11,217,492	8.50	$4,758,344	$7,954,920	2.67
Residential Adaptive Thermostats	27,000	$16,094,082	$1,836,000	$2,025,000	$150,000	$0	$1,986,000	$14,108,082	8.10	$2,175,000	$13,919,082	7.40
Residential CER	10,441	$42,290,068	$15,139,921	$15,461,213	$2,538,787	$0	$17,678,708	$24,611,360	2.39	$18,000,000	$24,290,068	2.35
RA Overall TRC	**45,988**	**$231,543,744**	**$57,102,463**	**$28,142,333**	**$6,385,477**	**$7,985,813**	**$71,473,753**	**$160,069,991**	3.24	**$42,513,623**	**$189,030,121**	**5.45**

	2018 Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Low Income TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Multi-Family Homes - Part 3	257	$12,945,630	$5,282,740	$2,821,839	$991,457	$0	$6,274,197	$6,671,434	2.06	$3,813,296	$9,132,334	3.39
Single Family Homes - Part 9	2,310	$6,712,076	$4,103,837	$5,389,207	$1,037,993	$0	$5,141,830	$1,570,246	1.31	$6,427,200	$284,876	1.04
LI Overall TRC	**2,567**	**$19,657,706**	**$9,386,577**	**$8,211,046**	**$2,029,450**	**$2,349,163**	**$13,765,190**	**$5,892,516**	1.43	**$12,589,659**	**$7,068,047**	**1.56**

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Witnesses: R. Idenouye
S. Moffat
F. Oliver Glasford
B. Ott
R. Sigurdson

Table 4: 2019 TRC-Plus and PAC Analysis and Ratios

	2019 Total Resource Acquisition & Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Multi-Year TRC & PACT Scenarios	**Participants or Units Installed**	**Total NPV Benefits**	**Total Incremental Costs**	**Total Variable Costs**	**Total Fixed Costs**	**Total Administrative Costs**	**TRC Total Costs**	**TRC Net Benefit**	**TRC Ratio**	**PACT Total Cost**	**PACT Net Benefit**	**PACT Ratio**
Resource Acquisition & Low Income	**52,248**	**$255,681,751**	**$70,276,315**	**$37,459,577**	**$8,204,095**	**$10,542,211**	**$89,022,621**	**$166,659,129**	**2.87**	**$56,205,884**	**$199,475,867**	**4.55**
Resource Acquisition	49,697	$235,754,398	$60,798,348	$29,084,310	$6,134,056	$8,146,065	$75,078,469	$160,675,929	3.14	$43,364,431	$192,389,967	5.44
Low Income	2,551	$19,927,353	$9,477,967	$8,375,267	$2,070,039	$2,396,147	$13,944,152	$5,983,200	1.43	$12,841,453	$7,085,900	1.55

	2019 Resource Acquisition						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Resource Acquisition TRC Scenarios	**Participants or Units Installed**	**Total NPV Benefits**	**Total Incremental Costs**	**Total Variable Costs**	**Total Fixed Costs**	**Total Administrative Costs**	**TRC Total Costs**	**TRC Net Benefit**	**TRC Ratio**	**PACT Total Cost**	**PACT Net Benefit**	**PACT Ratio**
Large Customers												
Large Custom	741	$120,852,411	$34,153,811	$5,367,806	$1,313,331	$0	$35,467,142	$85,385,270	3.41	$6,681,137	$114,171,274	18.09
Large Prescriptive	4,244	$14,190,332	$636,488	$743,203	$585,527	$0	$1,222,014	$12,968,317	11.61	$1,328,729	$12,861,602	10.68
Small Customers												
Small Custom	109	$7,009,613	$5,003,047	$433,823	$393,833	$0	$5,396,880	$1,612,733	1.30	$827,656	$6,181,958	8.47
Small Prescriptive	1,905	$15,128,779	$285,612	$751,776	$197,058	$0	$482,670	$14,646,109	31.34	$948,834	$14,179,946	15.94
Small DI	1,632	$12,967,525	$244,810	$3,572,634	$1,280,876	$0	$1,525,686	$11,441,839	8.50	$4,853,511	$8,114,015	2.67
Residential Adaptive Thermostats	28,271	$16,851,785	$1,922,438	$2,120,336	$98,164	$0	$2,020,602	$14,831,183	8.34	$2,218,500	$14,633,285	7.60
Residential CER	12,795	$44,352,678	$18,552,141	$16,094,732	$2,265,268	$0	$20,817,410	$23,535,268	2.13	$18,360,000	$25,992,678	2.42
RA Overall TRC	**49,697**	**$235,754,398**	**$60,798,348**	**$29,084,310**	**$6,134,056**	**$8,146,065**	**$75,078,469**	**$160,675,929**	**3.14**	**$43,364,431**	**$192,389,967**	**5.44**

	2019 Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Low Income TRC Scenarios	**Participants or Units Installed**	**Total NPV Benefits**	**Total Incremental Costs**	**Total Variable Costs**	**Total Fixed Costs**	**Total Administrative Costs**	**TRC Total Costs**	**TRC Net Benefit**	**TRC Ratio**	**PACT Total Cost**	**PACT Net Benefit**	**PACT Ratio**
Multi-Family Homes - Part 3	263	$13,280,443	$5,413,973	$2,878,276	$1,011,286	$0	$6,425,259	$6,855,184	2.07	$3,889,562	$9,390,881	3.41
Single Family Homes - Part 9	2,288	$6,646,910	$4,063,994	$5,496,991	$1,058,753	$0	$5,122,747	$1,524,163	1.30	$6,555,744	$91,166	1.01
LI Overall TRC	**2,551**	**$19,927,353**	**$9,477,967**	**$8,375,267**	**$2,070,039**	**$2,396,147**	**$13,944,152**	**$5,983,200**	**1.43**	**$12,841,453**	**$7,085,900**	**1.55**

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Witnesses: R. Idenouye
S. Moffat
F. Oliver Glasford
B. Ott
R. Sigurdson

Table 5: 2020 TRC-Plus and PAC Analysis and Ratios

	2020 Total Resource Acquisition & Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Multi-Year TRC & PACT Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Resource Acquisition & Low Income	**50,352**	**$260,322,740**	**$66,612,468**	**$38,228,079**	**$8,348,867**	**$10,753,591**	**$85,714,926**	**$174,607,814**	**3.04**	**$57,330,537**	**$202,992,203**	**4.54**
Resource Acquisition	47,817	$240,117,830	$57,047,601	$29,685,307	$6,237,427	$8,309,522	$71,594,550	$168,523,280	3.35	$44,232,255	$195,885,574	5.43
Low Income	2,535	$20,204,910	$9,564,867	$8,542,773	$2,111,440	$2,444,070	$14,120,376	$6,084,534	1.43	$13,098,282	$7,106,629	1.54

	2020 Resource Acquisition						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Resource Acquisition TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Large Customers												
Large Custom	744	$121,320,555	$34,286,112	$5,475,162	$1,339,597	$0	$35,625,709	$85,694,846	3.41	$6,814,760	$114,505,796	17.80
Large Prescriptive	4,261	$14,245,301	$638,953	$758,067	$597,237	$0	$1,236,190	$13,009,110	11.52	$1,355,304	$12,889,997	10.51
Small Customers												
Small Custom	111	$7,149,808	$5,103,110	$442,499	$401,710	$0	$5,504,819	$1,644,989	1.30	$844,209	$6,305,599	8.47
Small Prescriptive	1,943	$15,431,360	$291,324	$766,811	$200,999	$0	$492,323	$14,939,037	31.34	$967,810	$14,463,550	15.94
Small DI	1,665	$13,226,880	$249,707	$3,644,087	$1,306,494	$0	$1,556,200	$11,670,680	8.50	$4,950,581	$8,276,299	2.67
Residential Adaptive Thermostats	29,094	$17,342,293	$1,978,395	$2,182,053	$80,817	$0	$2,059,212	$15,283,081	8.42	$2,262,870	$15,079,423	7.66
Residential CER	10,000	$46,170,016	$14,500,000	$16,416,626	$2,310,574	$0	$16,810,574	$29,359,442	2.75	$18,727,200	$27,442,816	2.47
RA Overall TRC	**47,817**	**$240,117,830**	**$57,047,601**	**$29,685,307**	**$6,237,427**	**$8,309,522**	**$71,594,550**	**$168,523,280**	3.35	**$44,232,255**	**$195,885,574**	**5.43**

	2020 Low Income						TRC + 15% Societal Benefits			PACT + 15% Societal Benefits		
Low Income TRC Scenarios	Participants or Units Installed	Total NPV Benefits	Total Incremental Costs	Total Variable Costs	Total Fixed Costs	Total Administrative Costs	TRC Total Costs	TRC Net Benefit	TRC Ratio	PACT Total Cost	PACT Net Benefit	PACT Ratio
Multi-Family Homes - Part 3	270	$13,622,533	$5,540,329	$2,935,841	$1,031,512	$0	$6,571,841	$7,050,692	2.07	$3,967,353	$9,655,180	3.43
Single Family Homes - Part 9	2,265	$6,582,377	$4,024,538	$5,606,931	$1,079,928	$0	$5,104,466	$1,477,911	1.29	$6,686,859	-$104,482	0.98
LI Overall TRC	**2,535**	**$20,204,910**	**$9,564,867**	**$8,542,773**	**$2,111,440**	**$2,444,070**	**$14,120,376**	**$6,084,534**	1.43	**$13,098,282**	**$7,106,629**	**1.54**

RESPONSE

a) Enbridge's Net TRC Benefits, or the total net present value of all avoided gas, electricity, and water costs for each year of DSM less the cost of delivering DSM programs and the incremental costs borne by customers, from 1995 to 2014 are $2,483.9 million. In the Company's view this is the most appropriate representation of cumulative economic savings over the course of Enbridge's DSM experience.

b) Unfortunately Enbridge is unclear regarding the data requested by Environmental Defence in b) above. The above inquiry clearly indicates a desire to include all avoided costs, which would imply that the electricity, water and gas costs incorporated into the TRC calculation have been requested. However, these values are always represented over the entire measure life of DSM measures or activities. Representing only a single year of these savings creates a challenge given that they are compared against incremental costs to customers. The incremental cost of DSM to customers is a single year value, which in some instances would be greater than a single year's representation of TRC benefits. Further, the TRC calculation does not incorporate the cost of DSM incentives to customers, which ultimately drive rate impacts and thus can represent a cost of DSM depending on the analysis being undertaken.

c) Please see b) above.

d) Please see Enbridge's response to Environmental Defence Interrogatory #13, filed as Exhibit I.T3.EGDI.ED.13.

e) Please see Enbridge's response to Environmental Defence Interrogatory #13, filed as Exhibit I.T3.EGDI.ED.13.

Witnesses: S. Mills
S. Moffat
F. Oliver-Glasford
B. Ott

ENVIRONMENTAL DEFENCE INTERROGATORY #1

INTERROGATORY

Reference: Ex. C, Tab 3, Sch. 4, Pages 2 – 4

Please provide the following information with respect to Enbridge's 2017 a) industrial; b) commercial & institutional; c) residential; and d) low-income DSM programs:

a) Forecast TRC Test benefit/cost ratios;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

When answering this interrogatory please exclude DSM programs and budgets that pertain to Large Final Emitters and "voluntary participants" in the cap and trade program who purchase their own emission allowances.

RESPONSE

Given that it is still only Q1 of 2017, Enbridge is not in a position to provide forecasts of the requested information for 2017. At this point in time, the best evidence of the Company's DSM activities in 2017 by the various rate classes identified in the question is the evidence filed by the Company in support of its Multi-year DSM Plan 2015-2020 (EB-2015-0049). It is the Company's expectation that at this early stage in the year, there would not be a material difference between the 100% targets set out in the approved Multi-year plan and any forecasts which would benefit from only 2 months of program operations.

It is also appropriate to point out the significant effort that would be required to develop such forecasts even if this were possible at this point in time. Such forecasts would require critical inputs that include, but are not limited to:

Witness: M. Lister

- 2017 natural gas savings targets, set according to 2016 audited result (the 2016 audit process has not yet started);
- 2016 Annual Report results;
- Wholesale 2017 electricity rates (available Q2 2017);
- Wholesale 2017 water and sewage rates;
- 2016 program participation rates (available Q2 2017);
- Updates to inputs and assumptions in the Technical Reference Manual; and
- April 2017 Natural Gas Commodity Price.

It would take a great deal of time and resources to capture and collate the above data for the purposes of providing such forecasts. The Company would then have to manually back out of the forecasts the contributions of LFE and known Cap & Trade voluntary participants.

In terms of the forecast impact of DSM on GHG emissions reductions, the Compliance Plan has for the purposes of generating the GHG tariff, netted out the forecast impact of its DSM programs. At this stage, Enbridge does not believe that its forecasts in this regard require change.

April 5th, 2017 - ADDENDUM

As stated previously, the best evidence of the Company's DSM activities in 2017 is in the evidence filed by the Company as part of its Multi-Year DSM Plan 2015-2020 (EB-2015-0049). In efforts to be responsive to the above request Enbridge has amended its previous response and provided information based on the evidence as filed in EB-2015-0049 consistent with the approach taken by Union Gas.

a) - d) Please refer to Table 1 for Enbridge's Total Resource Cost ("TRC") values for the following customer segments. TRC benefits are derived from the savings as filed in EB-2015-0049, modified to remove the 15% non-energy benefit adder at ED's request. The TRC costs have been updated to reflect budget adjustments per the Board's Decision and Order in EB-2015-0049.

Table 1: 2017 TRC				
	TRC Benefits[1]	TRC Costs[2,3]	TRC Net Benefits	TRC Ratio
	(a)	(b)	(c)=(a-b)	(d)-(a/b)
Residential	$ 35,828,981	$ 23,075,000	$ 12,753,981	1.6
Commercial/Industrial	$ 133,018,806	$ 43,128,662	$ 89,890,144	3.1
Low Income	$ 14,399,534	$ 10,691,942	$ 3,707,592	1.3

e) -f) Table 2 below provides 2017 DSM budgets, annual natural gas savings, and lifetime natural gas savings for each customer segment.

Table 2: 2017 Forecast Savings		
	Annual DSM Savings (m^3)[4]	Lifetime DSM Savings
Residential	12,289,000	184,335,000
Commercial/Industrial	51,122,200	768,575,895
Low Income	6,151,533	92,273,000

g) As a result of the annual DSM natural gas savings created in 2017, the expected Greenhouse Gas ("GHG") emission reductions are 130,430 C02e[5].

h) As a result of the lifetime DSM natural gas savings created in 2017, the expected Greenhouse Gas ("GHG") emission reductions are 1,959,720 C02e[6].

i) Per the Board's Decsion and Order (EB-2015-0049), Enbridge's 2017 DSM budget is $62,933,844[7].

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[1] As filed in EB-2015-0049, Exhibit B, Tab 2, Schedule 3.
[2] TRC cost values updated per Decision and Order in EB-2015-0049
[3] TRC cost values do not include overhead and administrative costs as they are applied at the Resource Acquisition, Market Transformation and Low Income portfolio level for the purpose of cost-effectiveness screening
[4] As filed in EB-2015-0049 Exhibit I.T2.EGDI.STAFF.7
[5] Assumes 1.875kg of $CO2_e$ are emitted for each m3 gas that is consumed
[6] Assumes 1.875kg of $CO2_e$ are emitted for each m3 gas that is consumed
[7] As approved in the Decision and Order (EB-2015-0049)

At this time the Company is not in a position to extract Large Final Emitters (“LFE”) and Voluntary Participants from its DSM programs and budgets. Further, the Company does not believe this analysis to be relevant to a review of its 2017 Compliance Plan, and would suggest the DSM Mid-Term Review as the most appropriate venue for such analysis.

TABLE A1

TABLE 1: 2017 CUSTOMER-RELATED VOLUMES, EMISSIONS, COST OF EMISSIONS AND UNIT RATE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line	Rate	Budget Forecast Volumes[1]	LFE, Voluntary Participant and Other Exempt Gas Volumes[2]	Net Volumes[3]	Net CO_2e Emissions[4]	Assumed Cost of Allowances[5]	Cost of CO_2e Emissions[6]	Unit Rate[7]
		(10^3m^3)	(10^3m^3)	(10^3m^3)	(Tonnes CO_2e)	(\$/tonne CO_2e)	(\$)	(¢/m^3)
1.1	1	4,911,477.9	0.0	4,911,477.9	9,207,189.1	17.70	162,967,246.7	
1.2	6	4,862,269.2	120,126.9	4,742,142.3	8,889,748.0	17.70	157,348,539.5	
1.3	9	262.8	0.0	262.8	492.7	17.70	8,719.9	
1.4	100	0.0	0.0	0.0	0.0	17.70	0.0	
1.5	110	861,434.8	403,080.8	458,354.0	859,242.8	17.70	15,208,597.3	
1.6	115	490,291.9	304,439.5	185,852.4	348,403.9	17.70	6,166,749.5	
1.7a	125	305,896.4	0.0	305,896.4	573,441.7	17.70	10,149,917.2	
1.7b	125D[8]	325,082.3	0.0	325,082.3	609,408.1	17.70	10,786,522.6	
1.8	135	60,899.0	0.0	60,899.0	114,162.9	17.70	2,020,683.5	
1.9	145	63,318.2	14,091.0	49,227.2	92,282.6	17.70	1,633,402.7	
1.10	170	296,313.0	183,005.6	113,307.4	212,409.1	17.70	3,759,641.3	
1.11	200	170,842.7	170,842.7	0.0	0.0	17.70	0.0	
1.12	300	35,440.4	34,992.0	448.4	840.6	17.70	14,878.3	
1	Total Customer-Related	12,383,528.6	1,230,578.5	11,152,950.1	20,907,621.4	17.70	370,064,898.6	3.3181

Notes:

(1) Exhibit B, Tab 2, Schedule 1, Table 1, Col. 1 - Col. 2

(2) Exhibit B, Tab 2, Schedule 1, Table 1, Col. 4 and Col. 5. Rate 300 is landfill gas volume.

(3) Col. 1 - Col. 2

(4) Exhibit B, Tab 3, Schedule 1, Table 1, Col. 5

(5) Internal forecast of carbon allowance pricing based on past auction data and Cap and Trade Regulation

(6) Col. 4 x Col. 5

(7) (Col. 6 / (Col. 3 x 1000)) x 100

(8) Dedicated unbundled customers

Customer-Related Unit Rate Calculation

Cap and Trade Customer Related Charge = Cost of CO_2e Emissions / Net Volumes
= \$ 370,064,898.6 / 11,152,950.1 10^3m^3
= 3.3181 ¢/m^3

TABLE A2

TABLE 2: 2017 FACILITY-RELATED VOLUMES, EMISSIONS, COST OF EMISSIONS AND UNIT RATES

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	
Line		Volumes[1]	CO_2e Emissions[2]	Assumed Cost of Allowances[3]	Cost of CO_2e Emissions[4]	Unit Rate	
		(10^3m^3)	(Tonnes CO_2e)	($/tonne CO_2e)	($)	(¢/m^3)	
2.1	Company Use						
2.1.1	Fleet	1,500.0	2,811.9	17.70	49,771.3		
2.1.2	Buildings	1,505.9	2,823.0	17.70	49,967.6		
2.1.3	Boilers	3,930.2	7,307.8	17.70	129,348.0		
2.1	Company Use	6,936.2	12,942.8	17.70	229,086.9	0.0018	5
2.2	Unaccounted For Gas (UAF)	98,279.0	184,236.5	17.70	3,260,985.5	0.0271	6
2.3	Compressor Fuel	17,191.8	31,966.0	17.70	565,797.5	0.0048	7
2	Total Facility-Related	122,407.0	229,145.2	17.70	4,055,870.0	0.0337	

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Table 2
(2) Exhibit B, Tab 3, Schedule 1, Table 3, Col. 5
(3) Internal forecast of carbon allowance pricing based on past auction data and Cap and Trade Regulation
(4) Col. 2 x Col. 3
(5) Cost of CO_2e emissions / Total customer-related volume = [Col. 4 / (Exhibit A1, Table 1, Line 1, Col. 1 x 1000)] x 100
(6) Cost of CO_2e emissions / (Total customer-related volume - Rate 125D customers - landfill gas volume) = [Col. 4 / ((Exhibit A1, Table 1, Line 1, Col. 1 - Line 1.7b, Col. 1 - Line 1.12, Col. 2) x 1000)] x 100
(7) Cost of CO_2e emissions / (Total customer-related volume excluding unbundled customers (Rates 125 and 300) + Rate 325 Volume) = [Col. 4 / ((Exhibit A1, Table 1, Line 1, Col. 1 - Line 1.7a, Col. 1 -
- Line 1.7b, Col. 1 - Line 1.12, Col. 1 + 190,328 10^3 m^3)) x 1000] x 100

Facility-Related Unit Rate Calculations

Company Use = Cost of CO_2e Emissions for Company Use / Total Customer-Related Volume
= $ 229,086.9 / 12,383,528.6 10^3m^3
= 0.0018 ¢/m^3

Unaccounted For Gas Volumes = Cost of CO_2e Emissions for Unaccounted For Gas / (Total Customer-Related Volume Excluding Rate 125D and Landfill Gas)
= $ 3,260,985.5 / (12,383,528.6 - 325,082.3 - 34,992.0) 10^3m^3
= 0.0271 ¢/m^3

Compressor Fuel Volumes = Cost of CO_2e Emissions for Compressor Fuel / (Total Customer-Related Volume Excluding Unbundled Customers + Rate 325 Volume)
= $ 565,797.5 / (12,383,528.6 - 305,896.4 - 325,082.3 - 35,440.4 + 190,328.0) 10^3m^3
= 0.0048 ¢/m^3

Facility-Related Charge = 0.0018 + 0.0271 + 0.0048 ¢/m^3
= 0.0337 ¢/m^3

TABLE A3

TABLE 3: 2017 CAP & TRADE UNIT RATE SUMMARY

Line		Col. 1 Unit Rate (¢/m³)	
1	Customer-Related	3.3181	1
	Facility-Related:		
2.1	Company Use	0.0018	2
2.2	UAF	0.0271	3
2.3	Compressor Fuel	0.0048	4
2	Facility-Related	0.0337	5
3	Total	3.3518	6

Notes:

(1) Exhibit A1, Table 1, Line 1, Col. 8

(2) Exhibit A2, Table 2, Line 2.1, Col. 5

(3) Exhibit A2, Table 2, Line 2.2, Col. 5

(4) Exhibit A2, Table 2, Line 2.3, Col. 5

(5) Line 2.1 + Line 2.2 + Line 2.3

(6) Line 1 + Line 2

COMPLIANCE PLAN – ABATEMENT ACTIVITIES – CUSTOMER

1. Enbridge anticipates that renewable natural gas, low-carbon technologies and energy efficiency will play a role in future compliance plans where possible and appropriate.

2. As also noted in Exhibit C, Tab 2, Schedule 1 of the Framework, the Board lists a number of Potential GHG Abatement Measures for consideration including:

Table 1 – Customer-related and facility-related emission abatement opportunities

Measure	Applicability to Utilities
Customer abatement activities	Customer emissions
Renewable energy and fuel switching	Facility and customer emissions
New technologies	Facility and customer emissions
Building retrofits	Facility and customer emissions
Measures to mitigate and reduce fugitive emissions	Facility emissions
Biogas, renewable natural gas[1]	Facility and customer emissions

3. The Board goes on to state in section 5.3 that in its evaluation of the cost consequences of the Utilities' Compliance Plans it will consider whether the utility has "engaged in strategic decision-making and risk mitigation," "whether the Utility has considered a diversity (portfolio) of compliance options" and "whether a Utility has selected GHG abatement activities and investments that, to the extent possible, align with other broad investment requirements and priorities of the Utility in order to extract the maximum value from the activity or investment."

[1] Enbridge notes that biogas and renewable natural gas should be broadened to include renewable hydrogen and other renewable content as applicable for natural gas pipelines.

Witnesses: M. Lister
S. Mills
F. Oliver-Glasford
D. Teichrob
J. Tideman

4. Lastly, the Board notes in section 5.6 of the Framework that the introduction of abatement activities under the Cap and Trade program "creates the potential for significant overlap between existing DSM programs and future Compliance Plans." The Board concludes that "The DSM Framework also includes a mid-term review provision (to be completed by June 1, 2018) that will provide an appropriate opportunity to assess the DSM Framework in light of the Cap and Trade program."

A. Demand Side Management ("DSM")

5. Enbridge shares the Board's view regarding the potential for overlap between DSM programs and future Cap and Trade Compliance Plans.

6. Further, the Company agrees that the DSM Mid-Term Review will provide ample opportunity to consider the relationship between DSM programs and other future customer abatement activities, which should include a review of DSM's role within the Company's overall compliance planning activities. A focused evaluation of the level, pacing, and cost effectiveness of DSM as a compliance tool within the DSM Mid-Term Review will allow the Company to consider the inclusion of DSM within a Compliance Plan beyond 2017, while also avoiding disruption of the Company's existing DSM programs currently in market.

7. Given the timing of the release of the Framework, the Company has not had sufficient time to plan, design, or implement any proposals for additional rate payer funded DSM customer abatement activities within its 2017 Compliance Plan. As stated above, this is a topic area that the Company believes is more appropriately dealt with during the DSM Mid-Term Review.

8. While the Company has not incorporated incremental ratepayer funded abatement activities into its 2017 Compliance Plan, the forecast presented in Exhibit B, Tab 2,

Schedule 1 does, however, include incremental customer abatement activities as part of the Green Investment Fund (GIF) program, that has been funded by taxpayers.

9. In 2016 Enbridge entered into an agreement with the Ministry of Energy (“MOE”) to offer an advanced home energy audit and retrofit program over the course of three years through the GIF. The primary objective of this program is to help homeowners save on their energy bills year after year while also reducing overall GHG emissions. The whole home retrofit program was designed to be similar to Enbridge’s existing DSM offer, the Home Energy Conservation program, and is available to all customers regardless of primary fuel type. In addition, the funding was also meant to increase the deployment of the Adaptive Thermostats offer, also consistent with the Company’s DSM program, as well as funding to pursue educational and behavioural-based GHG reductions.

10. For illustrative purposes the following table, Table 2, outlines the forecasted lifetime savings related to the incremental GIF program:

Table 2 – Green Investment Fund Forecasted Results

Program Impacts	Unit	2016	2017	TOTAL
Budget	$ Millions	$9.70	$22.70	**$32.40**
Number of Participants	Homes	3,000	10,000	**13,000**
Total GIF Program Savings[1]	Annual m^3	2,059,500	10,984,000	**13,043,500**
Total GIF Program Savings	Lifetime m^3	61,785,000	205,950,000	**267,735,000**
Total Lifetime CO_2e Reductions	Tonnes	115,847	386,156	**502,003**
Estimated CO_2e Reductions Taking Place in Each Year[1]	**Tonnes**	**3,862**	**20,595**	**24,457**

1. CO_2e reductions and volume savings taking place in each year include the 50% of the impact of annual reductions achieved in the current year and 100% of the reductions achieved in past years. This methodology is intended to roughly capture the reality that participants do not all begin reducing emissions on Jan. 1st of a given year; they are enrolled throughout the year. For example, in the 2017 calendar year the full 100% impact of 2016 achievement and 50% of 2017 achievement has been included. The "TOTAL" column listed for this row represents the total annual CO2e reductions and volumes that will persist in 2019 and beyond.

Witnesses: M. Lister
S. Mills
F. Oliver-Glasford
D. Teichrob
J. Tideman

11. The numbers shown in Table 2 represent the forecasted m^3 volumes and CO_2e reductions for this 2017 compliance period. The forecasted 2016 values have been presented along with 2017, as the anticipated program impacts (due to the timing launch of the program) will be most notable in the 2017 compliance period. For the purposes of determining impact on the annual carbon compliance, 502,003 tonnes in CO_2e reductions is the best estimate of the lifetime savings attributable to the GIF program delivered by Enbridge.

12. In summary, the Company believes that DSM should be considered a vital part of its overall long-term Compliance Plan. This is especially so where the results from conservation and energy efficiency can be shown to be more cost effective over the long term than the purchase of compliance instruments. Given the timing of the release of the Framework, and given the scheduled Mid-Term Review for the Company's DSM Framework, <u>the Company believes the issue of including the existing and any incremental DSM activity into the Company's compliance planning acitivities is best suited for the Mid-Term Review.</u>

<u>B. Renewable Content Objectives for Natural Gas Pipelines</u>

13. Enbridge believes that establishing a renewable content objective for natural gas pipeline systems can provide a flexible low-carbon solution that offers good value to customers because it leverages the existing natural gas transmission, distribution and storage infrastructure as well as the heating, water heating and other gas-fired equipment used by our customers. Next to conservation, the addition of a renewable content objective, for natural gas pipelines, is expected to offer one of the more cost-effective carbon abatement measures for Ontario to broadly meet its GHG reduction and climate change mitigation goals.

Witnesses: M. Lister
S. Mills
F. Oliver-Glasford
D. Teichrob
J. Tideman

Ontario

Ontario Energy Board

Report of the Board

Regulatory Framework for the Assessment of Costs of Natural Gas Utilities’ Cap and Trade Activities

EB-2015-0363

September 26, 2016

3 Guiding Principles for Assessment of Costs

The OEB expects Utilities to develop Compliance Plans that outline how they will meet their obligations under Ontario's *Climate Change Act* and *Cap and Trade Regulation*. The OEB will review these Plans for prudence and reasonableness in meeting Cap and Trade obligations with a view to determining the appropriate costs to be recovered from natural gas customers in rates.

The OEB will not approve the Utilities' Compliance Plans. Utilities are responsible for deciding on the exact makeup of activities to be included in their Plans, how best to prioritize and pace investments in Cap and Trade compliance options and abatement activities, and how and when to participate in the market.

The Regulatory Framework describes how the OEB intends to assess the Utilities' Compliance Plans for cost-effectiveness and reasonableness and describes the information to be included in a Plan to assist the OEB in assessing and monitoring the Plans for prudence and protecting the interests of customers.

The OEB review of Utility Compliance Plans will be informed by a number of guiding principles intended to encourage optimal decision-making by Utilities and appropriate rate protection for customers. This principle-based approach will provide the Utilities the flexibility to develop compliance strategies that are responsive to changing market and volume conditions and that best suit their operations and customer base.

3.1 The Guiding Principles

The OEB's assessment of the reasonableness of Compliance Plan costs for recovery in rates will be guided by the following principles:

- **Cost-effectiveness**: cap and trade activities are optimized for economic efficiency and risk management
- **Rate Predictability**: customers have just and reasonable, and predictable rates resulting from the impact of the Utilities' cap and trade activities
- **Cost Recovery**: prudently incurred costs related to cap and trade activities are recovered from customers as a cost pass-through

5.3 Approach to Assessment of Cost Implications of the Utilities' Compliance Plans

Consistent with the Regulatory Framework's six guiding principles discussed in Section 3, in determining whether the cost consequences of the Utilities' Compliance Plans are cost-effective, optimized and reasonable, the OEB will consider the following:

1. whether a Utility has engaged in strategic decision-making and risk mitigation, resulting in a Compliance Plan that is as cost-effective as possible in reducing its facility-related and customer-related GHG emissions, and whether the Utility has considered a diversity (portfolio) of compliance options;

2. whether a Utility has selected GHG abatement activities and investments that, to the extent possible, align with other broad investment requirements and priorities of the Utility in order to extract the maximum value from the activity or investment; and,

3. whether the Compliance Plans are sufficiently flexible to adapt to variability in volume, changes in market prices, market dynamics and other sources of risk thereby providing for greater rate predictability as well as mitigating the risk to customers of changes in the Cap and Trade market.

5.3.1 **Assessment of Cost-Effectiveness and Optimization**

Inherent in the OEB's review of cost-effectiveness and reasonableness is an assessment of whether Compliance Plans reflect optimized decision-making. This includes:

- A consideration of a diversity of compliance options;
- Risk mitigation;
- Whether a Utility has approached its compliance strategy in an integrated manner that extracts maximum value from commitments that integrate multiple benefits; and,
- Whether a Utility has demonstrated flexibility to adapt to changes.

The OEB believes that assessing the Utilities' plans through this lens will lead to cost-effectiveness and greater rate predictability, and will reduce the costs and risk to customers.

To carry out this assessment, the OEB will expect robust and thorough information from the Utilities. The OEB will want to see information from the Utilities that demonstrates they have undertaken a detailed analysis which supports their choice of compliance options, including use of the OEB MACC to pace and prioritize their investments.

Most stakeholders that commented on the issue of Compliance Plan assessment were generally supportive of the OEB's approach. Some environmental groups felt that the cost-effectiveness test should be based on total societal costs and benefits (TRC [Total Resource Cost] or SCT [Societal Cost Test]), and that the OEB should require Utilities to undertake abatement where it is less costly than the procurement of allowances.

Given the newness of the Cap and Trade program the OEB considers it premature to apply the TRC or SCT to the Utilities' Compliance Plans at this time. The OEB will consider the use of additional tests such as the TRC or SCT after gaining experience with the assessment of Compliance Plans.

The OEB's approach to assessing the cost-effectiveness and reasonableness of Compliance Plans is discussed below.

5.3.1.1 Compliance option analysis and optimization of decision-making

The OEB's assessment will require a general understanding of the Utilities' approach to compliance. The OEB expects a Utility to provide an overview of its strategy, including an outline of the activities that it proposes to take to meet its compliance obligations (such as procurement of allowances and offset credits, GHG abatement programs for natural gas customers, and GHG abatement and mitigation activities for the Utility's own facilities and operations, and the rationale behind their selection of compliance actions and activities.

As part of its assessment of cost-effectiveness and reasonableness, the OEB will assess whether the Utilities effectively used the OEB MACC, their forecasts, and any other inputs to prioritize and select the compliance instruments and activities they have decided to include in their Compliance Portfolio.

The OEB will use the information provided by the Utilities to assess whether Compliance Plans reflect optimized and strategic decision-making, including consideration of a diversity of compliance instruments. The OEB will also use the information provided by the Utilities to assess whether a Utility has selected investments in GHG abatement activities[4] that, to the extent possible, align with other general investment needs and priorities of the Utility in order to extract maximum value from any GHG abatement activities.

The OEB recognizes that although some longer-term investments in GHG abatement may be more expensive than the price of emissions units in any given year, there may be strategic value in investments that decrease emissions over the longer term. For any activities included in the Compliance Plans that are more expensive per tonne of CO_2e than the annual carbon forecast price, the Utilities should provide a qualitative and quantitative description of the strategic value in these investments (e.g., long-term considerations related to GHG mitigation and the increasing price of emissions units in the longer term).

The OEB also recognizes that in any given year, a Utility may develop a Compliance Plan in which the only activity proposed is the procurement of allowances (and offset credits), if the Utility has determined that this is the most cost-effective and reasonable approach.

The implementation of a Cap and Trade program is a new activity for the Utilities and will require processes for ensuring that any procurement and trading decisions related to carbon emissions units are governed appropriately, similar to activity related to gas supply acquisitions. For the OEB to properly assess whether the Utilities' Compliance Plans are cost-effective and reasonable it will be important to understand how the Utilities have structured their decision-making and ensured they have adequate resources to manage the implementation of the Plan.

5.3.1.2 Performance Metrics and Cost Information

The OEB's assessment of cost-effectiveness and reasonableness will include a consideration of metrics and cost information to be provided by the Utilities. The OEB must assess the cost effectiveness of the Utilities' compliance activities in meeting their emission reduction obligations for customers and their own facilities. That assessment will include a consideration of objective and independent analysis of Utilities' Compliance Plan implementation performance and costs.

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[4] The customer-related GHG abatement activities must be incremental to the Utilities' 2015-2020 multi-year DSM plans (EB-2015-0029/EB-2015-0049).

The metrics and cost information will allow the OEB to assess whether the Utilities have considered a diversity of compliance options and their costs, and whether the Utilities have selected investments in GHG abatement activities that are cost-effective and extract maximum value. The OEB will rely on the performance metrics in the monitoring of the Utilities' activities to ensure continuous improvement in the planning and actions taken to achieve compliance, and the achievement of the government's objectives under the *Climate Change Act.*

Performance Metrics

The OEB will rely on performance benchmarks for the purpose of assessing forecast costs of Compliance Plans. Performance benchmarks will provide objective measures of the Utilities' proposed compliance activities. To assess the cost effectiveness of the Utilities' Compliance Plans, the OEB will require a Utility to calculate and provide key performance metrics, including cost per tonne ($/tonne) of each compliance instrument or activity and a comparison of costs of investing in GHG abatement activities versus procuring emissions units. The OEB MACC will establish benchmarks for the cost per tonne, as will the results of the allowance auctions, the annual and long-term carbon price forecasts and other carbon market information.

A few stakeholders suggested adding additional metrics, such as a cost per customer, or undertaking further work to develop metrics given the lack of experience with Cap and Trade programs. The metrics that the OEB will use for the assessment of the Utilities' Compliance Plans are intended to measure both cost-effectiveness and reasonableness. The assessment will not be based on an upper limit of costs as would be the case with a cost per customer metric. Rather, because compliance is an obligation for the Utilities, the assessment will need to focus on the most cost-effective approach. This does not mean that the OEB will not consider customer bill impacts, only that the implementation of Cap and Trade cannot be tied to a specific cost per customer. In many cases the costs of the Compliance Plans will be largely dependent on prices in the Cap and Trade market and the cost of abatement opportunities.

With experience reviewing Compliance Plans, and through the monitoring process, there will be an opportunity to identify new metrics that may be useful in the assessment of Utilities' requests for cost recovery. As discussed in Section 8, the OEB intends to establish a working group that will consider, among other things, the need for and design of potential new metrics for evaluating the Utilities' Plans and performance.

5.6 Customer Abatement Programs and the Demand Side Management Framework

As part of the 2013 Long Term Energy Plan, the Minister of Energy, issued a Directive dated March 26, 2014, which directed the OEB to develop a DSM policy framework for natural gas distributors for the period January 2015 to December 2020. The OEB issued its multi-year Demand Side Management (DSM) framework (EB-2014-0134)[5] on December 22, 2014, and subsequently approved 2015-2020 DSM Plans for two of the Utilities.

The DSM framework is designed to reduce natural gas consumption throughout Ontario, and includes the OEB's policies on all elements of the Utilities' DSM activities. Utility DSM Plans[6] include annual targets and performance measurement tools related to the Utilities' DSM activities. The DSM framework also includes an OEB-led evaluation, measurement and verification ("EM&V") process to ensure that the Utilities are only rewarded for the natural gas savings directly attributable to the customer-funded DSM programs previously approved by the OEB.

The introduction of the Cap and Trade program requires Utilities to meet emissions reduction obligations, which creates the potential for significant overlap between existing DSM programs and future Compliance Plans.

Several stakeholders argued that customer-funded DSM has now been supplanted by the Cap and Trade program and therefore customer-funded DSM should be discontinued.

The OEB is confident that any potential overlap can be appropriately addressed through the robust EM&V process of the DSM framework. The DSM framework also includes a mid-term review provision (to be completed by June 1, 2018) that will provide an appropriate opportunity to assess the DSM framework in light of the Cap and Trade program.

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5 http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2014-0134&sortd1=rs_dateregistered&rows=200

6 http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/513656/view/

6 Cost Recovery

As discussed in section 5, the Compliance Plans will include procurement and investment strategies that the Utilities will use to meet their GHG compliance obligations. These compliance obligations will have costs associated with them. These costs will include:

- Facility-related obligations for facilities owned or operated by the Utilities for the purpose of distribution, transmission and storage of natural gas;
- Customer-related obligations for natural gas-fired generators, and residential, commercial and industrial customers who are not Large Final Emitters (LFEs) or voluntary participants; and,
- Administrative costs to meet their compliance obligations.

Customer-related and facility-related obligation costs will be incurred for emissions units procurement and for GHG abatement programs. The amount of these costs will be determined by the OEB through its assessment of each of the Utilities' Compliance Plans.

For emissions units procurement, the Utilities will be indifferent as to whether they are purchasing emissions units for their customers, their facilities or both. Consequently, the OEB will expect that the emissions units procurement costs will be a total cost that includes both customer-related and facility-related obligations.

For abatement programs, each of the Utilities will likely develop targeted programs for their residential, commercial and industrial customers. The Utilities will also develop programs for reducing emissions from their own facilities. The OEB will therefore expect to see a separation of customer-related and facility-related abatement program costs for the purpose of allocating costs to the appropriate customer classes, similar to DSM programs.

This section addresses the mechanisms for recovery of costs incurred by the Utilities to meet their Cap and Trade obligations including: cost causation, cost allocation, rate design and bill presentment, and the rate-setting approaches (including re-calibration and the true up process).

8 Monitoring and Reporting

The OEB will require annual monitoring and reporting by the Utilities on the results of their Cap and Trade activities and any changes to their Compliance Plans. Ongoing monitoring of the Utilities' costs and performance is essential to achieving the OEB's guiding principles for the Regulatory Framework. Monitoring will support the OEB's assessment of future plans for cost-effectiveness and identify whether the Utilities are improving their planning and delivering greater value to customers.

The performance metrics used to monitor the Utilities' Compliance Plans will be the same as the performance metrics used to assess those plans:

- Costs per tonne ($/tonne) of each compliance instrument or activity;
- A comparison of costs of investing in GHG abatement activities versus procuring emission units over the short-term and long-term; and,
- Comparison of actuals with forecasts.

The OEB will also use the latest settlement price from the quarterly auctions to benchmark utility costs. It is important that the metrics used to monitor the plans are consistent for all Utilities as this will allow the OEB, ratepayer groups and other stakeholders to compare Plans as between the Utilities and over time.

The Utilities will file annual monitoring reports to align with the Utilities' annual review of Cap and Trade costs (as discussed in section 6). The OEB expects the Utilities to provide supporting documentation (including auction transactions, summaries of offsets and secondary market transactions, etc.) to allow the OEB to review the execution and performance of the Compliance Plans with regard to cost recovery.

The OEB notes that most stakeholders did not comment on the monitoring and reporting section in the Discussion Paper. The stakeholders that did comment were generally supportive of the Utilities filing annual monitoring reports with the OEB.

One ratepayer group suggested that the OEB establish a working group to define the reporting requirements and establish the metrics. The OEB has considered the suggestion of a working group and intends to establish one for the purpose of further refining metrics, but more importantly as a means to facilitate the monitoring and review of the Utilities' compliance activities and support the OEB's review of the Regulatory Framework during the initial Cap and Trade compliance period.

Appendix A: Filing Guidelines

Filing Guidelines for Natural Gas Utility Cap and Trade Compliance Plans

Introduction

These filing guidelines outline the minimum information necessary to be filed by natural gas utilities in order for the OEB to review the applicant's Cap and Trade Compliance Plan application. The applicant should review the Report of the Board, *Cap and Trade Regulatory Framework for the Assessment of Costs Natural Gas Utilities' Cap and Trade Activities* (OEB Report), which provides an explanation of the OEB's expectations and rationale for requiring the information outlined in these guidelines.

These filing guidelines include information the OEB will use to assess the utility's Compliance Plans, including:

- Forecasts and compliance plan documents;
- Reports to be filed annually for the purposes of monitoring the gas utility's compliance activities;
- Expected customer outreach and communication plans; and,
- Cost recovery documents (including annual re-calibration and true-up of Compliance Plans).

The applicant is expected to file information outlined in these filing guidelines in a separate application by August 1 of each year.

General Requirements

The basic format of an application for cost recovery of the applicant's Compliance Plan must include the following exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Forecasts
Exhibit 3	Compliance Plan Documents

consumption forecasts related to its operations (including unaccounted for gas losses, etc.).

The methodology to be used to prepare the volume forecasts will be the same OEB-approved methodology the utility already uses for the purpose of rate-setting. The utility must provide all supporting documentation regarding its forecasts. For the volume forecasts, the DSM forecasts and customer-related abatement activities forecasts[1] must be shown separately.

3 GHG Emissions Forecasts

The applicant must include its GHG emissions forecasts of the following emissions:

- Customer-related GHG emissions (emissions related to customers' natural gas usage) – as with the volume forecast, the utility will need to exclude GHG emissions of LFEs and voluntary participants
- Facility-related GHG obligations (related to the distribution, transmission and storage of natural gas) – this will include process emissions, emissions from fugitive and leaked gas, and emissions from the utility's facilities and operations

The methodology to be used by the utility to calculate these GHG emissions is contained in the government's GHG Reporting Regulation (Ontario Regulation 452,09as amended and Ontario's Guideline for Greenhouse Gas Emissions Reporting issued on May 19, 2016).

4 Annual Carbon Price Forecasts

The applicant must include:

- The forecast, which will be set using the average of the Intercontinental Exchange (ICE) daily settlement prices of a California Carbon Allowance for each day of the forecast period for each month of the forecast year. The forecast period shall be 21 business days and should be as close as possible to the forecast year
- All supporting documentation that outlines methodology, calculations and assumptions

[1] The GHG abatement activities must be incremental to the applicant's 2015-2020 multi-year DSM plans (EB-2015-0029/EB-2015-0049).

2. An explanation of how the utility's approach to compliance achieves the guiding principles set out in section 3 of the OEB Report as well as the assessment objectives of optimization, integration and adaptability set out in section 5.3 of the OEB Report.

3. An explanation of the utility's rationale for compliance options selection and reasons why alternative compliance options were not selected.

4. An explanation of how the utility used the OEB Marginal Abatement Cost Curve (MACC) to pace and prioritize compliance instruments to manage costs and risks.

5. A qualitative and quantitative explanation of how the compliance options selected by the utility are cost-effective and result in optimal decision-making.

6. An explanation of whether the utility's approach considers long-term (5-10 years) strategies for GHG abatement, and if so how these are considered. If not, the utility is to explain why it did not consider long-term abatement strategies.

7. For any activities included in the Compliance Plan that are more expensive per tonne of carbon dioxide equivalent than the annual carbon forecast price, a qualitative and quantitative description of the strategic value in these investments (e.g., long-term considerations related to GHG mitigation and the increasing price of emissions units in the longer term).

8. A comparison of costs of investing in GHG abatement activities versus procuring emissions units over the short-term and long-term.

Note: As noted in section3, any information that is Auction Confidential and/or Market Sensitive (as defined in the OEB Report) must be clearly marked confidential.

3. Performance Metrics and Cost Information

1. A quantitative and qualitative description of the total costs of the Compliance Plan portfolio, outlined by year and over the entire compliance period, including:
    a. Cost of total Compliance Plan
    b. Costs by year

c. Cost by year per compliance instrument/activity (Auction Confidential and Market Sensitive)

2. An outline of the utility's compliance options for each year of the Compliance Plan, including:
   a. Allowances (Auction Confidential and Market Sensitive)
      i. Number of allowances to be procured (through auctions and through bilaterals, over-the-counter (OTC), etc.)
      ii. Price of allowances (using annual forecast or OEB 10-year carbon price forecast)
      iii. Timing of procurement
      iv. Total forecasted cost
      v. Forecasted cost per tonne of GHG

   b. Offset credits (Market Sensitive)
      i. Number of offset credits to be procured (from government registries, bilaterals, OTC, etc.)
      ii. Forecasted price of offset credits
      iii. Timing of procurement
      iv. Total forecasted cost
      v. Forecasted cost per tonne of GHG

   c. Abatement activities – customer-related[2]
      i. Type of program
      ii. Total forecasted cost (include quantity and forecasted price by program)
      iii. Forecasted GHG reduction
      iv. Forecasted cost per tonne of GHG reduction

   d. Abatement activities – facility-related
      i. Type of program
      ii. Total forecasted cost (include quantity and forecasted price by program)
      iii. Forecasted GHG reduction
      iv. Forecasted cost per GHG tonne reduction

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[2] The GHG customer-related abatement costs must be incremental to the applicant's 2015-2020 multi-year DSM plans (EB-2015-0029/EB-2015-0049).

Final Report

Natural Gas Conservation Potential Study

June 30, 2016, updated on July 7, 2016

Submitted to:

Ontario Energy Board

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Executive Summary

Background and Objectives

Charged with regulating Ontario's natural gas and electricity sectors, the Ontario Energy Board (OEB) was directed by the Minister of Energy to have an achievable potential study completed for natural gas efficiency in Ontario.

The objective of this study is to estimate the achievable potential for natural gas efficiency in Ontario from 2015 to 2030, in order to:

- Inform natural gas Demand Side Management (DSM) program design and delivery at the mid-term review of the 2015-2020 DSM Framework
- Provide guidance to utilities for DSM program design and delivery beyond 2020
- Support the assessment of the role that DSM may serve in future distribution infrastructure planning processes at the regional and local levels

The scope of this work includes the planning and execution of an achievable potential study in the franchise areas of Union Gas Limited ("Union Gas") and Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution") collectively referred to as the "utilities". This study builds on the past natural gas utility achievable potential work as well as the OEB's 2015-2020 DSM Framework, the 2015-2020 DSM plans prepared by Union Gas and Enbridge Gas Distribution, annual reports of the utilities to the OEB, the 2015-2020 DSM Decision, DSM program evaluations, and other studies on DSM market characterization and technology assessments. This study also leverages input from the DSM Technical Working Group (TWG), which included experts proposed by stakeholders and representatives from the utilities, Independent Electricity System Operator, Ministry of Energy, and Environmental Commissioner of Ontario.

Given the emergence of the cap and trade initiative since the study was initiated, the carbon impacts were not included in the avoided costs analysis. It was determined that it would be prudent to defer consideration of the issue until final details related to the cap and trade initiative are available to inform the analysis. Instead, a sensitivity analysis has been undertaken to provide a preliminary assessment of what will be the impact of higher avoided costs on the economic potential.

Scope

The scope of this study is summarized below:

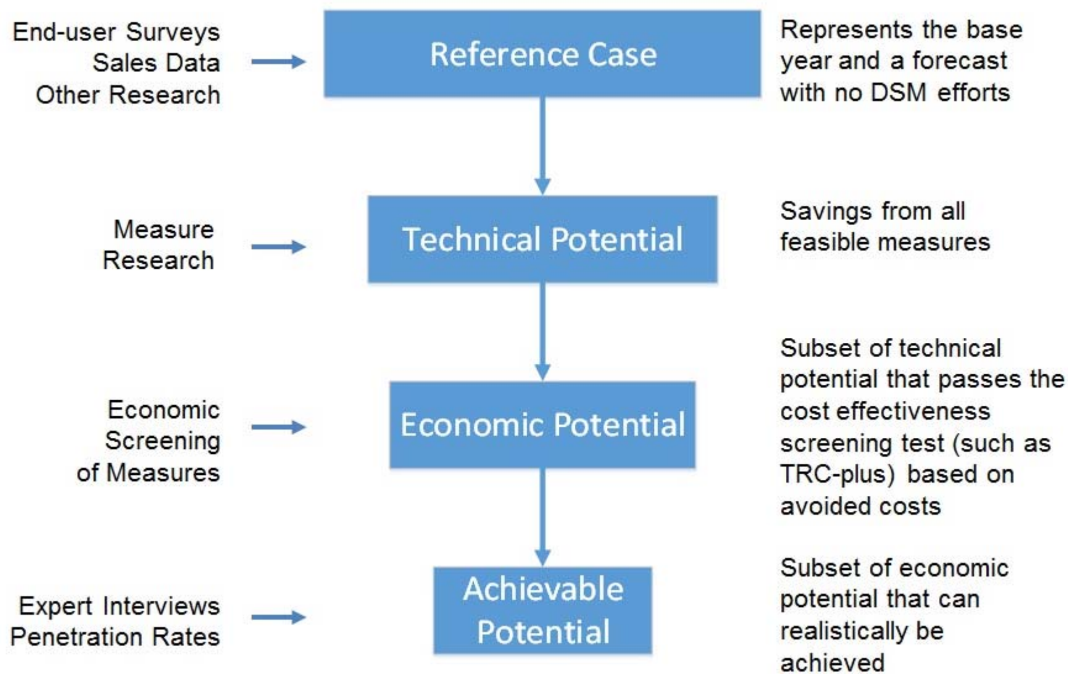
- **Sector Coverage:** The study addresses three sectors: residential, commercial[1], and industrial.
- **Geographical Coverage**: The study results are presented for the total Union Gas and Enbridge Gas Distribution franchise areas.
- **Study Period**: This study covers a 17-year period from 2014 to 2030. The base year for the study is the calendar year 2014. The base year was calibrated to the 2014 actual sales data provided by the gas utilities.
- **Measures:** The study addresses the full range of natural gas energy efficiency technologies, and operation, maintenance and control measures.

[1] Throughout this report the term "commercial" also includes institutional sectors, such as schools, hospitals, etc., unless otherwise noted.

Methodology

The study generally followed a traditional approach in determining the natural gas conservation potential in Ontario, as shown in Exhibit ES 1.

Exhibit ES 1 General methodology for potential studies



A reference case was first developed to represent the base year and a forecast that did not include any DSM efforts.[2] Next, three conservation potential scenarios were developed: the technical potential scenario (includes savings from all technically-feasible measures), the economic potential scenario (a subset of the technical potential that includes only those measures that are cost-effective using the TRC-plus[3] test) and finally, the achievable potential scenario. The achievable potential scenario is the subset of the economic potential savings that can realistically be achieved. Three achievable potential scenarios were analyzed: unconstrained (assumes no budget constraints or policy restrictions), semi-constrained (budgets were initially set at the levels approved by the OEB for 2015-2017, then gradually increased so they doubled by 2020 and remained at that level until 2030), and constrained (budgets from 2015-2020 are the OEB-approved budget levels and remain at 2020 level through 2030). In order to determine the achievable potential, ICF interviewed experts in the field of energy efficiency in the residential, commercial, and industrial sectors and developed adoption curves for all measures included in the analysis. More details on the methodology can be found in chapter 2.

[2] Please note that the reference case does not account for initiatives related to the Climate Change Action Plan, which was under development at the time the analysis was completed. It is anticipated that some of these initiatives would reduce gas consumption in the reference case forecast, which would reduce the achievable potential savings found in this study.

[3] The TRC-plus test is a benefit/cost ratio comparing benefits and cost of energy efficiency investments, and includes a 15% adder that accounts for the non-energy benefits associated with DSM programs, such as environmental, economic, and social benefits, as selected by the OEB in 2015-2020 DSM Framework. It is aligned with the cost effectiveness test used by the IESO, as per the Minister of Energy's Conservation First Framework. Please refer to the glossary for a full definition of TRC-plus.

Measures and Input Assumptions

The study considered technologies and operation, maintenance and control measures that save natural gas across energy end-uses in each sector. In total 52 measures were considered in the residential sector, 59 measures in the commercial sector, and 57 measures in the industrial sector. More details on the measures and input assumptions can be found in chapter 2.

As in any study of this type, the results presented in this report are based on a number of additional important assumptions. Those assumptions include the current penetration of measures and the rate of future growth in the building stock. Wherever possible, the assumptions used in this study are consistent with those used by the OEB and the utilities. As such, the reader should use the results presented in this report as best available estimates; major assumptions, information sources, and caveats are noted throughout the report.

Avoided Costs

Avoided costs are one of the key components of the cost-effectiveness tests that are used to evaluate energy efficiency investments. The natural gas avoided costs used in this study include direct natural gas supply and infrastructure costs that can be avoided by the utilities as a result of a decrease in demand. The avoided cost analysis includes three main components: natural gas commodity costs which represent about 75% of total avoided costs; upstream capacity costs (pipeline and storage costs upstream of the utility citygate) which represents about 17% of total avoided costs; and, downstream distribution system costs (transmission, storage and distribution system downstream of the utility citygate) which represents about 8% of total avoided costs. A detailed description of the avoided costs is provided in chapter 3.

Overall Study Findings

The study findings confirm the existence of significant cost-effective opportunities for natural gas savings in Ontario. Exhibit ES 2 and Exhibit ES 3 show the reference case and the savings associated with the various conservation potential scenarios discussed above. Exhibit ES 4 presents a summary of the total achievable potential savings and program costs for all three sectors for each achievable potential scenario in 2020 and in 2030.

Exhibit ES 2 Total Reference, Technical, Economic and Achievable Potential Annual Natural Gas Consumption

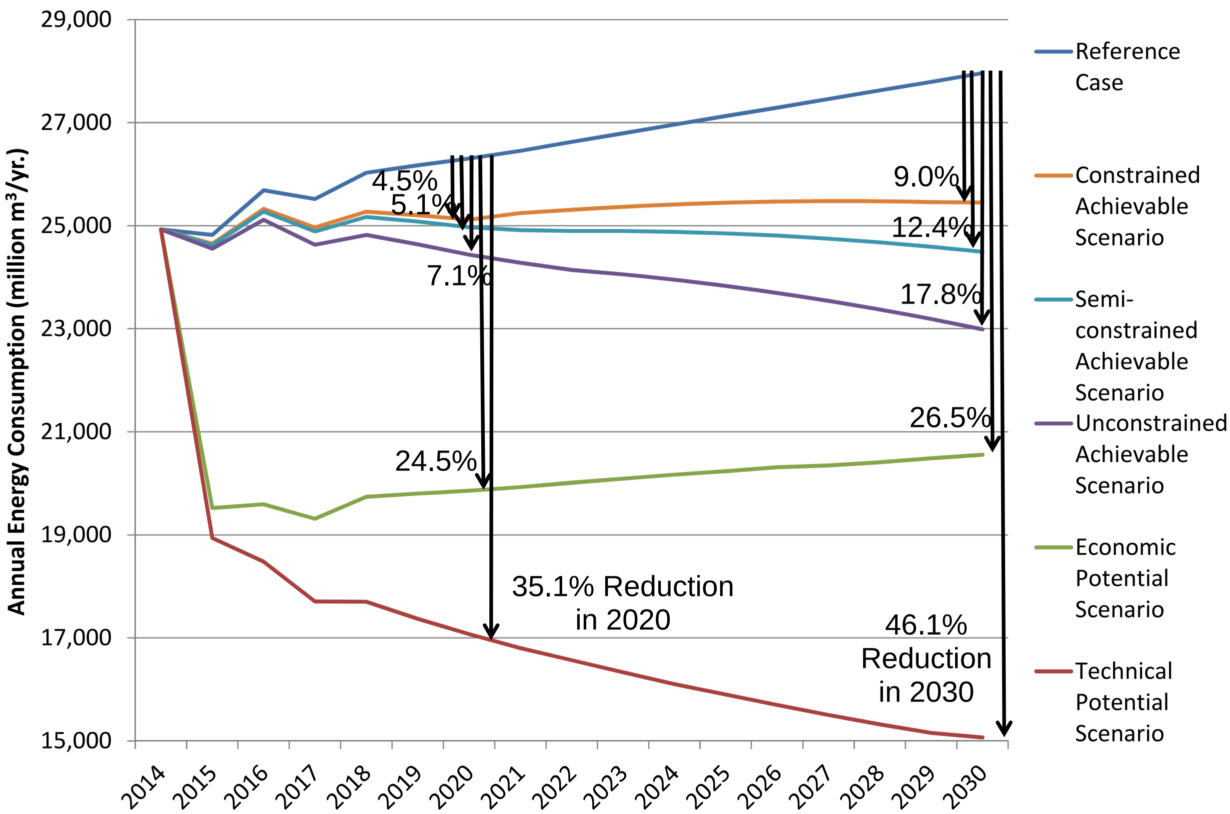


Exhibit ES 3 Total Technical, Economic, and Achievable Potential Annual Savings Relative to Reference Case

Year	Reference Case Use (million m³/yr.)	Technical Potential		Economic Potential		Unconstrained Achievable Potential		Semi-constrained Achievable Potential		Constrained Achievable Potential	
		Absolute Savings (million m³/yr.)	Savings Relative to Reference Case (%)	Absolute Savings (million m³/yr.)	Relative to Reference Case (%)	Absolute Savings (million m³/yr.)	Relative to Reference Case (%)	Absolute Savings (million m³/yr.)	Relative to Reference Case (%)	Absolute Savings (million m³/yr.)	Relative to Reference Case (%)
2015	24,821	5,880	23.7%	5,299	21.3%	267	1.1%	195	0.8%	171	0.7%
2016	25,690	7,211	28.1%	6,096	23.7%	575	2.2%	414	1.6%	362	1.4%
2017	25,518	7,811	30.6%	6,205	24.3%	891	3.5%	631	2.5%	555	2.2%
2018	26,029	8,326	32.0%	6,290	24.2%	1,209	4.6%	859	3.3%	758	2.9%
2019	26,172	8,803	33.6%	6,369	24.3%	1,534	5.9%	1,094	4.2%	969	3.7%
2020	26,306	9,233	35.1%	6,448	24.5%	1,869	7.1%	1,338	5.1%	1,187	4.5%
2025	27,128	11,229	41.4%	6,891	25.4%	3,295	12.1%	2,276	8.4%	1,681	6.2%
2030	27,962	12,896	46.1%	7,409	26.5%	4,973	17.8%	3,468	12.4%	2,510	9.0%

Total technical potential: The results show that the adoption of all technically-feasible measures could reduce total consumption by 35.1% by 2020 and 46.1% by 2030.[4]

Total economic potential: Adoption of all measures that are economically viable (i.e. are cost-effective), have the potential to reduce total consumption by 24.5% by 2020 and 26.5% by 2030.

Total achievable potential: The unconstrained, semi-constrained, and constrained achievable potential scenarios could reduce total consumption by 7.1%, 5.1%, and 4.5%, respectively, by 2020, and by 17.8%, 12.4%, and 9.0%, respectively, by 2030.

Exhibit ES 4 Total Technical, Economic and Achievable Potential Savings and Program Cost Results[5]

Value	Unconstrained		Semi-Constrained		Constrained	
	Year					
	2020	2030	2020	2030	2020	2030
Annual Savings (million m^3/yr.)	1,869	4,973	1,338	3,468	1,187	2,510
Measure Lifecycle Savings (million m^3)	28,582	82,756	18,909	55,386	14,115	39,831
Value of Savings (million $)	16,456	96,600	12,938	78,266	9,142	58,628
Program Spending to Milestone Year (million $)	3,298*	11,544*	893	3,330	666	1,917
Average Annual Program Spending (million $/yr.)	550*	722*	149	208	111	120
Average Program Spending up to Milestone Year ($/$m^3$)	0.12*	0.14*	0.05	0.06	0.05	0.05

**Note: These are not specific program costs but are the total costs for the scenario.*

Unconstrained program results: With unconstrained budget, all sector programs combined could achieve 1,869 million cubic metres of annual savings, or 28.6 billion cumulative cubic metres of savings by 2020, at a total cost of $3.3 billion or on average $550 million per year. All sector programs combined could achieve 5.0 billion cubic metres of annual savings, or 82.8 billion cumulative cubic metres of savings by 2030, at a total cost of $11.5 billion or on average $722 million per year.

Semi-constrained program results: A program budget for all sectors of $893 million for 2015-2020, or $149 million per year, could achieve 1.3 billion cubic metres of annual savings, or 18.9 billion cumulative cubic metres of savings, by 2020. A program budget of $3.3 billion to 2030 could achieve 3.5 billion cubic metres of annual savings, or 55.4 billion cumulative cubic metres of savings, by 2030. This level of spending up to 2030 represents 29% of the total spending of the

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[4] The large technically-feasible savings available are driven largely by the inclusion of electric air-source and ground-source heat pumps in the residential and commercial sectors of the study. Although these technologies do not currently pass the TRC-plus economic screen, they technically have the potential to eliminate a significant portion of the natural gas space heating in the province by 2030.

[5] The annual savings represent the natural gas saved each year by measures implemented in the years up to a milestone year.

The measure lifecycle savings present the natural gas saved over the lifetime of the measure installed up to that year, taking into account repeated installation of measures with lifetimes shorter than the period in question.

The value of the savings is the sum of the stream of avoided cost savings over the measure lifecycle for all the measures, with all savings discounted back to the year of installation.

The program spending to milestone year represents the sum of program spending for all years up to a given milestone year without discounting.

The average annual program spending is the total program spending up to a given milestone year divided by the number of years until that milestone year.

The average program spending up to milestone year is the total program spending divided by the total measure lifecycle savings.

unconstrained program, while the total lifecycle savings of natural gas represent 67% of the total savings of natural gas in the unconstrained program.

Constrained program results: Under budget allocations for all sectors of $666 million for 2015-2020, or $111 million per year, programs could achieve 1.2 billion cubic metres of annual savings, or 14.1 billion cumulative cubic metres of savings by 2020. Under a budget allocation of $1.9 billion to 2030, programs could achieve 2.5 billion cubic metres of annual savings, or 39.8 billion cumulative cubic metres of savings by 2030. This level of spending up to 2030 represents 17% of the total spending of the unconstrained program, while the total lifecycle savings of natural gas represent 48% of the total savings of natural gas in the unconstrained program.

Exhibit ES 5 shows the GHG emission reductions associated with the total natural gas savings shown in Exhibit ES 3. The percent reduction of GHG relative to the reference case for each scenario are the same as that of the natural gas savings in Exhibit ES 2. More details on this analysis can be found in chapter 2.

Exhibit ES 5 Total Greenhouse Gas Emission Reductions Under all Scenarios[6]

Year	Reference Case Emissions (million kg CO_2/yr)	Technical Potential		Economic Potential		Unconstrained Achievable Potential		Semi-constrained Achievable Potential		Constrained Achievable Potential	
		GHG Reduction (million kg CO_2/yr)	Savings Relative to Reference Case (%)	GHG Reduction (million kg CO_2/yr)	Savings Relative to Reference Case (%)	GHG Reduction (million kg CO_2/yr)	Savings Relative to Reference Case (%)	GHG Reduction (million kg CO_2/yr)	Savings Relative to Reference Case (%)	GHG Reduction (million kg CO_2/yr)	Savings Relative to Reference Case (%)
2015	46,241	10,955	23.7%	9,872	21.3%	498	1.1%	364	0.8%	318	0.7%
2016	47,860	13,434	28.1%	11,356	23.7%	1,072	2.2%	771	1.6%	675	1.4%
2017	47,541	14,552	30.6%	11,560	24.3%	1,659	3.5%	1,175	2.5%	1,033	2.2%
2018	48,492	15,512	32.0%	11,717	24.2%	2,252	4.6%	1,600	3.3%	1,413	2.9%
2019	48,759	16,401	33.6%	11,866	24.3%	2,858	5.9%	2,038	4.2%	1,805	3.7%
2020	49,008	17,201	35.1%	12,013	24.5%	3,482	7.1%	2,492	5.1%	2,212	4.5%
2025	50,539	20,920	41.4%	12,838	25.4%	6,138	12.1%	4,240	8.4%	3,132	6.2%
2030	52,093	24,025	46.1%	13,803	26.5%	9,265	17.8%	6,460	12.4%	4,677	9.0%

[6] The Guideline for Greenhouse Gas Emissions Reporting December 2015, Ministry of the Environment and Climate Change. recommends an emission factor of 1.863 kg CO_2/m^3 for natural gas in Ontario, which was used in this calculation http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2015/012-4549_d_Guideline.pdf

3. Re exhibit I.T3.EGDI.ED.17:

This interrogatory reads as follows: “Section 5.1.3 and Appendix E contain a benchmarking analysis. Please reproduce the tables and figures contained therein including only those jurisdictions where the utilities in question are required to implement all cost-effective DSM.”

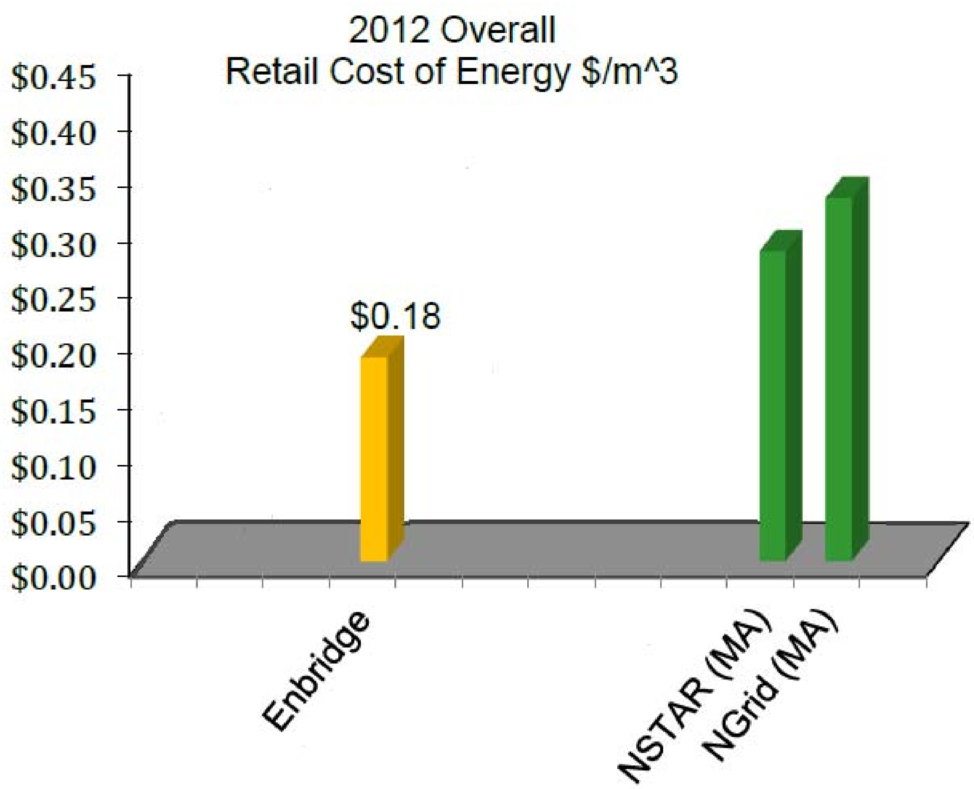
The response reproduced the tables appearing in Section 5.1.3 of the Navigant report but not those in Appendix E. Please also reproduce the tables and figures in Appendix E including only those jurisdictions where the utilities in question are required to implement all cost-effective DSM.

Enbridge provides the following response:

Please see on the following pages the revised versions of Figures E-1, E-2, E-3, E-4, E-5 and Table E-3. Please note that Enbridge has not investigated in detail the characteristics of the below noted utilities or their DSM portfolios. As such significant differences may exist in terms of the types of programs, technologies, input assumptions, adjustment factors, or other details between Enbridge’s DSM activities and those of the utilities displayed below.

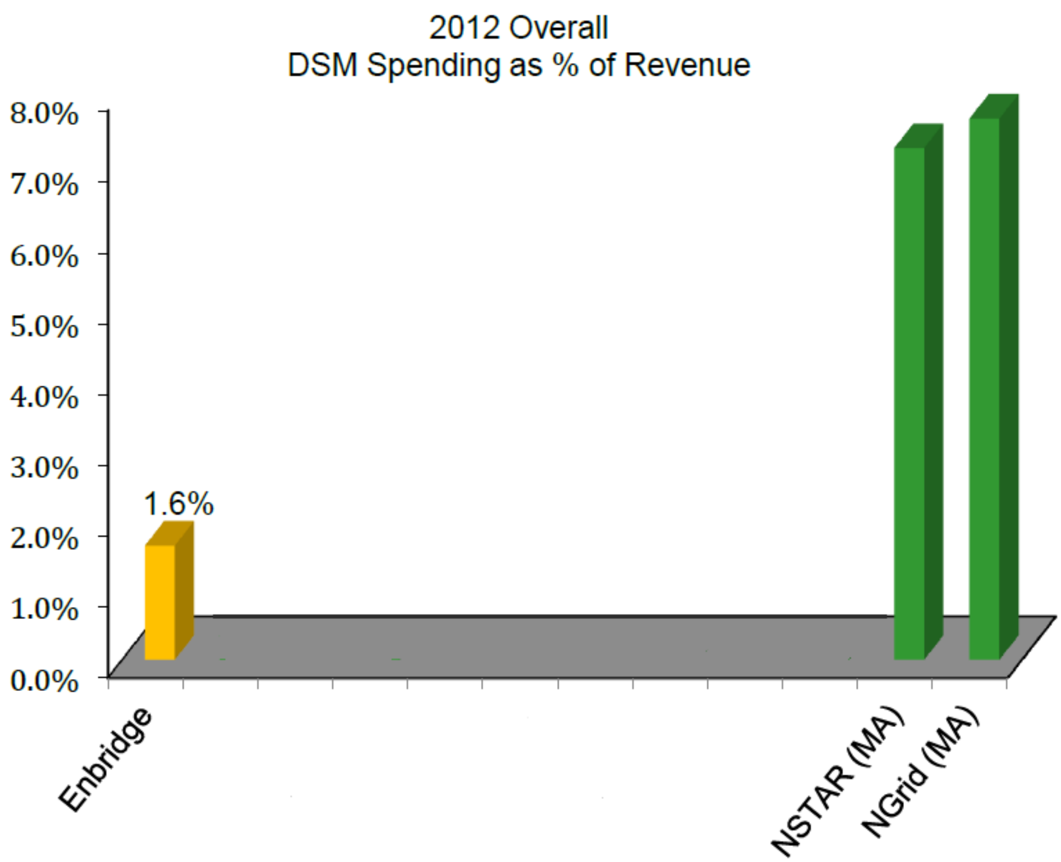
Witnesses: K. Mark
S. Moffat
B. Ott

Figure E-1. 2012 Retail Cost of Natural Gas [1,2,3,4,5,6,7]



Witnesses: K. Mark
S. Moffat
B. Ott

Figure E-2. 2012 DSM Spending as a Percentage of Revenue [1,2,3,4,5,6,7]



Witnesses: K. Mark
S. Moffat
B. Ott

Figure E-3. 2012 Gross Energy Savings as a Percentage of Gas Sales [1,2,3,4,5,6,7]

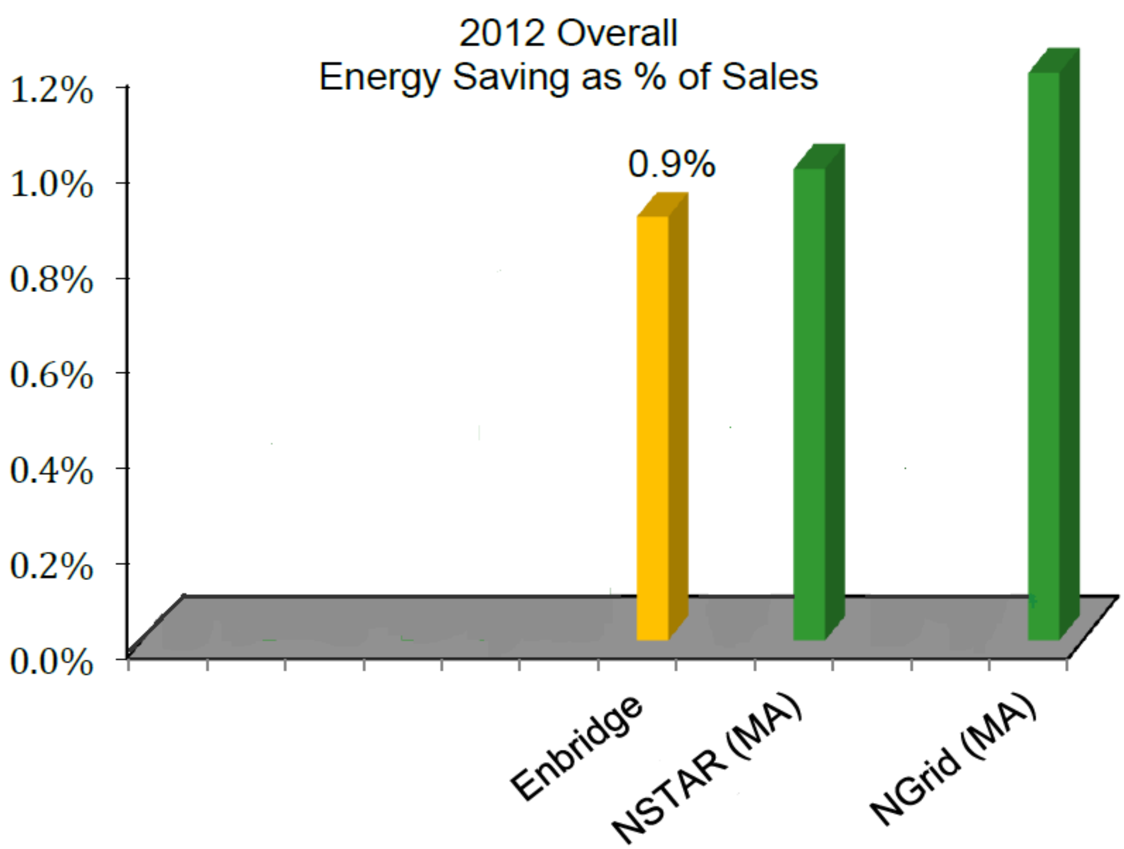
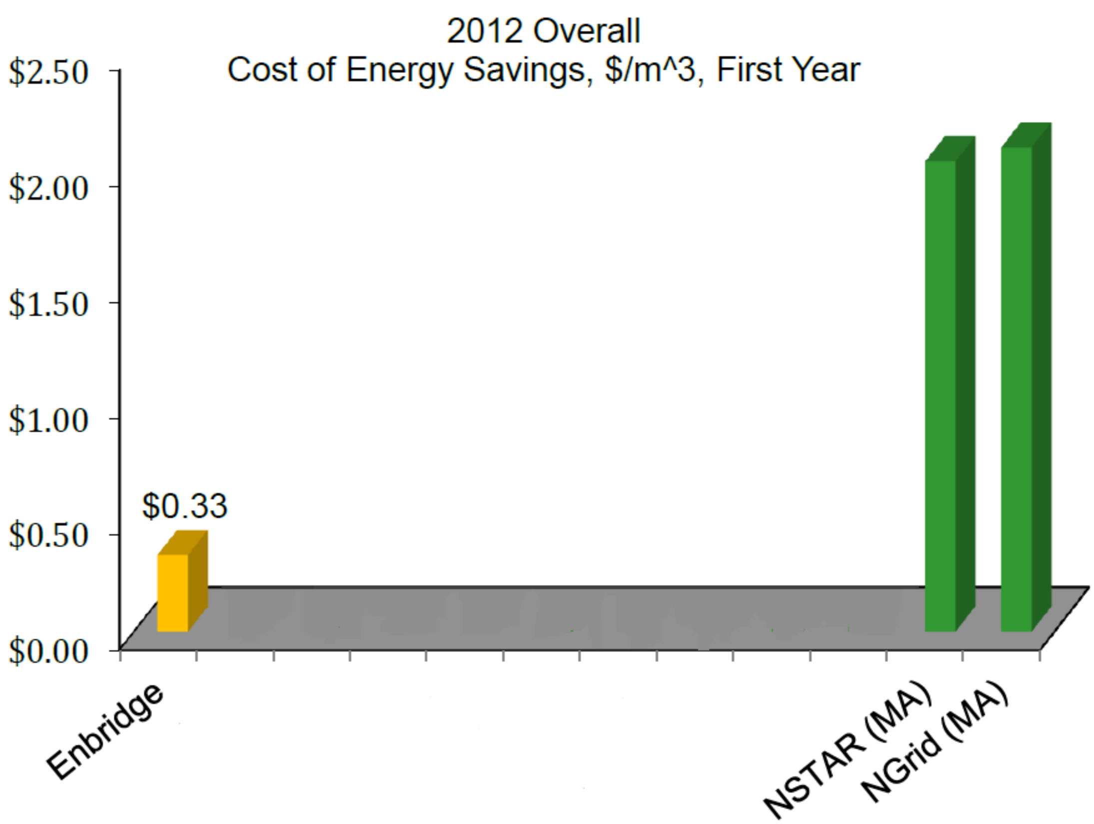
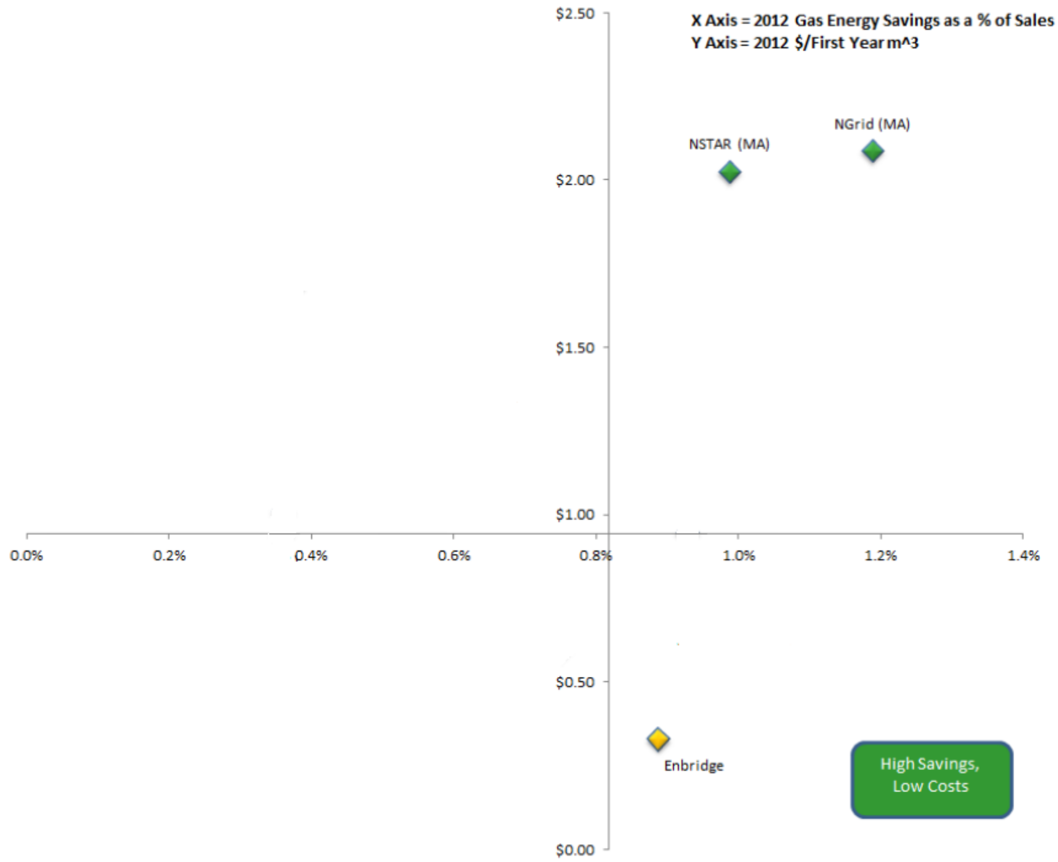


Figure E-4. 2012 Cost of Natural Gas Savings [1,2,3,4,5,6,7]



Witnesses: K. Mark
S. Moffat
B. Ott

Figure E-5. 2012 Natural Gas Savings and First Year Costs ($/m^3) Over All Sectors [1,2,3,4,5,6,7]



Witnesses: K. Mark
S. Moffat
B. Ott

Table E-3 Detailed Benchmark Data [1,2,3,4,5,6,7]
2012- DSM Results by State

		2012 Incremental DSM Results		2012 Retail				Normalized DSM Results		
Customer Sector	Utility	m3	Costs $M	Customers	Annual m3	Revenue $M	Cost of Energy $/m3	Spending as a % of Revenue	Energy Savings as a % of Sales	Cost of Savings $/m3
					Residential					
Canada	Enbridge	14,086,586	$16.6	1,929,313	3,868,127,000	$1,239	$0.32	1.3%	0.4%	$1.18
Massachusetts	NGrid	27,009,771	$71.1	808,556	1,942,084,180	$779	$0.40	9.1%	1.4%	$2.63
Massachusetts	NSTAR	4,867,191	$19.5	245,507	505,168,314	$212	$0.42	9.2%	1.0%	$4.01
					C&I					
Canada	Enbridge	78,445,878.0	$14.0	160,167.0	6,567,894,000	$666	$0.10	2.1%	1.2%	$0.18
Massachusetts	NGrid	14,108,121.2	$14.6	82,795.0	1,517,942,300	$346	$0.23	4.2%	0.9%	$1.04
Massachusetts	NSTAR	6,966,670.1	$4.4	27,295.0	692,874,911	$120	$0.17	3.7%	1.0%	$0.64
					Overall					
Canada	Enbridge	92,532,464.0	$30.6	2,089,480.0	10,436,021,000	$1,905	$0.18	1.6%	0.9%	$0.33
Massachusetts	NGrid	41,117,892.4	$85.8	891,361.0	3,460,026,479	1,124.6	$0.33	7.6%	1.0%	$2.03
Massachusetts	NSTAR	11,833,861.2	$24.0	272,802.0	1,198,043,225	332.2	$0.28	7.2%	1.0%	$0.66

[1] (0.2% annual savings in 2011, ramping up to 1.5% in 2019) (ACEEE (2014) *State and Local Policy Database: Illinois*, http://database.aceee.org/state/illinois#sthash.bGWyz5jh.dpuf)
[2] http://database.aceee.org/state/iowa#sthash.8lQbPs2e.dpuf
[3] http://database.aceee.org/state/michigan#sthash.TZP0sYSN.dpuf
[4] Vermont law requires program administrators to set *electricity* energy utility budgets at a level that would realize "all reasonably available, cost-effective energy efficiency. A separate proceeding for setting gas energy efficiency budgets is expected in the future, but is not currently in place.
[5] http://database.aceee.org/state/massachusetts#sthash.ulRAAgsM.dpuf
[6] The Green Communities Act requires that electric and gas utilities procure all cost-effective energy efficiency before more expense supply resources http://database.aceee.org/state/massachusetts#sthash.ulRAAgsM.dpuf).
[7] http://database.aceee.org/state/minnesota#sthash.Lr12YnGK.dpuf

Table 1: 2020 Goal and Annual Budgets and CCM Targets

Year	Budget ($ millions)	Cumulative Cubic Metres
2015	**$37,722,230**	**774,359,281**
2016	**$63,535,727**	**1,001,743,852**
2017	**$73,826,882**	**1,083,061,000**
2018	**$79,680,131**	**1,147,902,770**
2019	**$81,273,733**	**1,165,771,091**
2020	**$82,899,208**	**1,182,290,348**
2020 Natural Gas Savings Goal (m^3)		**6,355,128,342**

4. To establish context and orders of magnitude, a 2020 Goal of natural gas reductions through the Company's Multi-Year DSM efforts of 6.36 billion m^3 is the equivalent of removing nearly 2.6 million homes from the natural gas system for an entire year[1]. Likewise if translated into carbon emission reductions, the Company's 2020 Goal is the equivalent of reducing carbon emissions by 12 million tonnes[2], which translates to the removal of nearly 2.4 million cars from Ontario roads for a full year.[3] These carbon emission reductions will likely be of great assistance to the Province in pursuit of its greenhouse gas emission goals.

5. Of the total 2020 Goal, 774 million m^3 are derived from 2015. As a result of efforts from 2016 through 2020, 3,053 million m^3 will be contributed by large commercial and industrial customers in continuation of Enbridge's historical success working within this market segment to reduce consumption. A further 883 million m^3 will be

[1] Assumes each home uses 2,400 m^3 per year. This is the typical annual usage Enbridge reports for its Rate 1 residential customers.
[2] Assumes that each m^3 of natural gas consumed results in 1.89kg of carbon equivalent emissions, as per *Guideline for Greenhouse Gas Emissions Reporting* (as set out under Ontario Regulation 452/09 under the Environmental Protection Act), Appendix 10; ON.20, General Stationary Combustion, Calculation Methodology 1, Ontario Ministry of the Environment, December 2009, PIBS# 7308e.
[3] Assumes that the average automobile emits 5.1 tonnes of carbon equivalent emissions in a given year.

ENVIRONMENTAL DEFENCE INTERROGATORY #2

INTERROGATORY

Reference: Ex. C, Tab 3, Sch.4, Pages 2 – 4

Please provide all studies prepared by or for Enbridge with respect to the costs and benefits of increasing its 2017 DSM budget in order to achieve incremental greenhouse gas emission reductions.

RESPONSE

Enbridge has not prepared any studies with respect to the costs and benefits of increasing the 2017 DSM budget in order to achieve incremental greenhouse gas emission reductions. Please also refer to the response to Board Staff Interrogatory #19(b) filed at Exhibit I.1.EGDI.STAFF.19.

Witnesses: M. Lister
F. Oliver-Glasford

ENVIRONMENTAL DEFENCE INTERROGATORY #3

INTERROGATORY

Reference: Ex. G, Tab 1, Sch. 1, Appendix A, Table A3

Please provide your 2017 natural gas commodity charge per cubic metre.

RESPONSE

Based on the January 2017 QRAM (EB-2016-0326), the gas supply commodity charge is 11.45 ¢/m^3.

Witnesses: A. Kacicnik
A. Langstaff

ENVIRONMENTAL DEFENCE INTERROGATORY #4

INTERROGATORY

Reference: Ex. C, Tab 3, Sch. 4

Enbridge states that:

> “[T]he Company has not incorporated incremental ratepayer funded abatement activities into its 2017 Compliance Plan” (p. 2)
>
> “the Company believes the issue of including the existing and any incremental DSM activity into the Company’s compliance planning activities is best suited for the Mid-term Review.” (p. 4)

In light of the fact that the mid-term review of the DSM Framework will not be completed until June 1, 2018, does Enbridge plan to include incremental ratepayer funded customer abatement activities into its 2018 compliance plan? If yes, please provide an approximate range of the budget level for those activities that Enbridge believes is worth considering. If no, please fully explain and justify that position.

RESPONSE

Please refer to LIEN Interrogatory #4 filed at Exhibit I.1.EGDI.LIEN.4.

Witnesses: M. Lister
J. Tideman

Filed: 2017-03-17
EB-2016-0300
Exhibit I.5.EGDI.ED.5
Page 1 of 1

ENVIRONMENTAL DEFENCE INTERROGATORY #5

INTERROGATORY

Reference: Ex. C, Tab 3, Sch. 4

Please make best efforts to provide the following estimated incremental DSM results based on the assumption that Enbridge's 2017 DSM budget was increased by 25%:

a) Forecast TRC Test benefit/cost ratio;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

Please assume that the incremental budget would be spent as efficiently as possible. If possible, please assume that the incremental budget would be spent only in relation to customers whose emissions Enbridge is responsible for under cap and trade legislation. Please make and state any additional assumptions as necessary.

If it is necessary to assume a date on which Enbridge would have begun preparation and planning for the use of the incremental spending, please provide a response for two scenarios (a) the date that the draft regulations under the *Climate Change Act* were released (February 25, 2016); and (b) the date that the Cap and Trade Framework was released (September 26, 2016).

RESPONSE

The question incorrectly presupposes that it is possible to formulaically develop forecasts from a simple increase to the overall DSM budget. As Enbridge witnesses have clearly demonstrated in numerous proceedings before the Board, the generation of forecasts of benefits from DSM activities requires consideration of the specific program in question, the maturity of the program and the extent to which a market has been saturated. These and numerous other variables including the existence and availability of the Company's own resources are factors that must be considered before any credible forecasts could be made.

Please also see the response to Environmental Defence Interrogatory #1, filed at Exhibit I.5.EGDI.ED.1.

Witness: M. Lister

ENVIRONMENTAL DEFENCE INTERROGATORY #6

INTERROGATORY

Reference: Ex. C, Tab 3, Sch. 4

Please make best efforts to provide the following estimated incremental DSM results based on the assumption that Enbridge 2017 DSM budget was increased by 50%:

a) Forecast TRC Test benefit/cost ratio;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

Please assume that the incremental budget would be spent as efficiently as possible. If possible, please assume that the incremental budget would be spent only in relation to customers whose emissions Enbridge is responsible for under cap and trade legislation. Please make and state any additional assumptions as necessary.

If it is necessary to assume a date on which Enbridge would have begun preparation and planning for the use of the incremental spending, please provide a response for two scenarios (a) the date that the regulations under the *Climate Change Act* were issued (May 19, 2016); and (b) the date that the Cap and Trade Framework was issued (September 26, 2016).

RESPONSE

Please see the responses to Environmental Defence Interrogatories #1 and #5, filed at Exhibit I.1.EGDI.ED.1 and Exhibit I.5.EGDI.ED.5.

Witness: M. Lister

ENVIRONMENTAL DEFENCE INTERROGATORY #7

INTERROGATORY

Reference: Ex. C, Tab 3, Sch. 4

Please consider a scenario where the Board directs Enbridge to achieve as many tonnes of incremental greenhouse gas emissions reductions as possible via incremental cost-effective 2017 DSM spending, including through the expansion of budgets for existing programs. Based on that scenario, please estimate:

a) The forecast incremental 2017 greenhouse gas emission reductions (tonnes);
b) The forecast incremental lifetime greenhouse gas emission reductions (tonnes);
c) The estimated cost of purchasing carbon allowances or credits for the tonnes of emission indicated in response to parts (a) and (b) of this interrogatory.

Please assume that the direction is issued by the Board on May 1, 2017. Please state all other assumptions and provide all underlying calculations.

RESPONSE

Please see the responses to Environmental Defence Interrogatories #1 and #5, filed at Exhibit I.5.EGDI.ED.1 and Exhibit I.5.EGDI.ED.5.

Witness: M. Lister

Ontario

DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS UTILITIES

EB-2008-0346

Date: June 30, 2011

11. INCENTIVE PAYMENTS

In accordance with the E.B.O. 169-III Report of the Board dated July 23, 1993, the natural gas utilities are provided with a return for the DSM activities they undertake consistent with the return available for other distribution activities.[26] In addition to this return, an incentive payment should be available to the natural gas utilities to encourage them to aggressively pursue DSM savings and recognize exemplary performance. DSM financial incentive amounts should not be included in the natural gas utilities' return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The maximum incentive amount available for the 2012 program year should be $9.5 million for each of the two main natural gas utilities, to be escalated for inflation to determine the subsequent program year caps (the "Annual Cap"). The Annual Cap should be escalated using the GDP-IPI. The DSM incentive payments are pre-tax amounts.

To the extent that the *approved* DSM budgets deviate in magnitude from the Board proposed budgets, the Annual Cap should be scaled accordingly.[27] This will help ensure that the eligible incentive amount is consistent with the expected level of efforts require to achieve or exceed the approved targets. For greater clarity, and as implied by the proposed metrics outlined in section 9, the natural gas utilities will have an incentive to contain their *actual* costs while striving to achieve or exceed their targets; the proposed Annual Cap adjustment relates to the *approved* DSM budgets as opposed to actual expenditures.

The Annual Cap should be allocated among the three generic program types (i.e., resource acquisition, low-income, and market transformation programs) based on their approved DSM budget shares. For instance, if 10% of the *approved* annual DSM budget is allocated to one of the generic program types, then the maximum incentive available for results achieved under that generic program type will be 10% of the Annual Cap.

Likewise, incentive amounts paid to the natural gas utilities should be allocated to rate classes in proportion of the amount actually spent on each rate class. These incentive amounts should be tracked in a deferral account as further detailed in section 13.4.

As described in section 9, performance for all three generic types of programs (i.e., resource acquisition, low-income, and market transformation programs) will be evaluated using balanced scorecards. Also, as described in section 10, targets at 50%,

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[26] The Board determined in its E.B.O. 169-III Report of the Board dated July 23, 1993 that "approved DSM costs should be treated consistently with prudent supply-side costs. Long-term DSM investments should be included in rate base and short-term expenditures expensed as part of the utility's cost of service."

[27] For instance, if the approved DSM budget is 25% less in a given year than the budget proposed by the Board, the maximum incentive amount for that year will be reduced by 25%.

100% and 150% will be established for each metric on the scorecards. No incentive will be provided for achieving a scorecard weighted score of less than 50%. For each metric on the scorecard, results will be linearly interpolated between 50% and 100%, and between 100% and 150%. Metric results below 50% will be interpolated using the 50% and 100% targets, metric results above 150% will be interpolated using the 100% and 150% targets.[28]

To encourage performance beyond the 100% target level, a pivot point should be introduced at the 100% level. More specifically, 40% of the incentive available should be provided for performance achieving a scorecard weighted score of 100% level, with the remaining 60% available for performance at the 150% level.[29] As indicated in section 10, the natural gas utilities should file evidence on the challenges they will face in meeting each of their three scorecard levels (i.e., 50%, 100% and 150%).

The incentive amount should be capped at the scorecard weighted score of 150%. The maximum incentive amount allocated to each generic type of DSM program should equal the sum of the maximum incentive amounts available for achieving weighted scores of 150% or above on all the scorecards.

12. LOST REVENUE ADJUSTMENT MECHANISM ("LRAM")

Utilities recover their allowed distribution revenues through both a fixed and a variable distribution rate. These rates are based on forecast consumption levels for their respective franchise area that take into account, among other things, the expected impact of naturally occurring energy conservation and the impact of planned DSM activities. If the actual impact of natural gas DSM activities undertaken by the natural gas utility in its franchise area results in greater (less) natural gas savings than what was incorporated into the forecast, the natural gas utility will earn less (more) distribution revenue than it otherwise would have, all other things being equal.

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[28] For example, if the 50%, 100% and 150% targets are 40 units, 60 units and 70 units respectively, then a result of 10 units would imply a metric score of -25%.

i.e., $50\% - \dfrac{(100\% - 50\%)}{(60-40)} * (40-10) = -25\%$

A result of 80 units would imply a metric score of 200%.

i.e., $150\% - \dfrac{(150\% - 100\%)}{(70-60)} * (70-80) = 200\%$

[29] For example, if the maximum incentive available is $1 million, the incentive payment will be $400,000 if the weighted scorecard result is 100%, and $1 million if the weighted scorecard result is 150% or above. As results are to be linearly interpolated, a weighted scorecard result of 75% would lead to an incentive payment of $200,000.

i.e., $\$400{,}000 * \dfrac{(75\% - 50\%)}{(100\% - 50\%)} = \$200{,}000$

A weighted scorecard result of 125% would lead to an incentive payment of $700,000.

i.e., $\$400{,}00 + \$600{,}000 * \dfrac{(125\% - 100\%)}{(150\% - 100\%)} = \$700{,}000$

The potential for deviations from the forecasted impact of planned DSM activities and the actual impact of DSM activities undertaken by the natural gas utility introduces a risk and a disincentive for the natural gas utility to deliver those DSM programs. The LRAM is designed to remove this disincentive by truing up the actual impact of DSM activities undertaken by the natural gas utility from the forecasted impact.[30] Accordingly, the LRAM amount is a retrospective adjustment and may be an amount refundable to or receivable from the utility's customers, depending respectively on whether the actual natural gas savings resulting from the natural gas utility's DSM activities are less than or greater than what was included in the forecast for rate-setting purposes. A natural gas utility may only claim an LRAM amount in relation to DSM activities undertaken within its franchise area by itself and/or delivered for the natural gas utility by a third party under contract.

The LRAM amount is determined by calculating the difference between actual and forecast natural gas savings by customer class and monetizing those natural gas savings using the natural gas utility's Board-approved variable distribution charge appropriate to the rate class. As described in section 6 and 7, the input assumptions, savings estimates, and adjustment factors used in the calculation of the LRAM amount should be based on the best available information resulting from the evaluation and audit process of the same program year. For example, the 2012 LRAM amount will be based on the best available information resulting from the evaluation and audit process of the 2012 program year.

The natural gas utilities should calculate the first year impact of DSM programs on a monthly basis, based on the volumetric impact of the measures implemented in that month, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurs in. This approach will help ensure that LRAM amounts closely reflect the actual timing of the implementation of the DSM measures.

It is expected that new load forecasts will incorporate the impact of natural gas DSM activities already undertaken. Accordingly, LRAM amounts are only accruable until distribution rates based on a new load forecast are set by the Board.

The recording of LRAM amounts, and the disposition of the balance in the LRAM variance account, is described in sections 13.3 and 14 respectively.

13. Accounting Treatment

The DSM plan components (e.g., budget, LRAM, incentive structure, DSMVA) will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-year DSM plan. However, the DSM plan components will all be developed and measured on an annual basis within the multi-

[30] The LRAM serves to remove a disincentive for the gas utilities to undertake DSM programs. In contrast, the incentive payments as outlined in section 11. is meant to encourage the gas utilities to aggressively pursue DSM savings and recognize exemplary performance.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 3, pp. 24 - 25

Please provide the following information with respect to Union's 2017 a) industrial; b) commercial & institutional; c) residential; and d) low-income DSM programs:

a) Forecast TRC Test benefit/cost ratios;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

When answering this interrogatory please exclude DSM programs and budgets that pertain to Large Final Emitters and "voluntary participants" in the cap-and-trade program who purchase their own emission allowances.

Response:

a–d) Union's Total Resource Cost ("TRC")-Plus values are calculated at the program level for Residential, Commercial/Institutional, Low Income, Performance Based Conservation, and Large Volume as shown in Table 1 below. Union does not forecast DSM savings and TRC values at a customer level and cannot remove values associated with large final emmitters and voluntary participants.

The Performance Based Conservation program only includes values from RunSmart since the Strategic Energy Management program is not expected to generate savings in the 2017 program year. Union expects the Large Volume TRC in 2017 to be similar to the 2014 program year, the TRC value shown in Table 1 is for the 2014 program year with Rate T1 removed.

Table 1: 2017 TRC

Program	TRC-Plus Benefits[1] (a)	TRC Costs[2] (b)	TRC-Plus Net Benefits (c)=(a-b)	TRC Ratio (d)=(a/b)
Residential	$17,418,266	$16,726,828	$691,438	1.0
Commercial/Institutional	$171,144,966	$112,710,794	$58,934,172	1.5
Low Income	$8,990,002	$13,212,829	-$4,222,007	0.7
Large Volume[3]	$102,475,788	$25,181 ,158	$77,294,630	4.1
Performance Based Conservation	$194,934	$135,181	$59,753	1.4

e) Please see the response at Exhibit B.Staff.9 a).

f) Please see the response at Exhibit B.Staff.9 a).

g) Greenhouse Gas ("GHG") emission reductions are expected to be 300,096 tonnes CO2e as a result of 2017 DSM annual natural gas savings.

h) GHG emission reductions are expected to be 4,377,701 tonnes CO2e as a result of 2017 DSM cumulative natural gas savings.

i) As per the Board's EB-2015-0029/EB-2015-0049 Decision and Order[4], Union's 2017 DSM budget is $58,570,073.

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[1] Program savings as filed in 2015-2020 DSM Plan, EB-2015-0029 Application and Evidence, Tab 3, Appendix A
[2] TRC costs values as per EB-2015-0029 Decision and Order
[3] Large Volume TRC values are from the 2014 program year as per Union's 2014 Annual Report with Rate T1 removed
[4] See page 1 of the Decision and Order dated January 20, 2016.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 3, pp. 24 - 25

Please provide all studies prepared by or for Union with respect to the costs and benefits of increasing its 2017 DSM budget in order to achieve incremental greenhouse gas emission reductions.

Response:

There have been no such studies prepared by or for Union.

Filed: 2017-03-17
EB-2016-0296
Exhibit B.ED.3
Page 1 of 1

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 3, pp. 24 - 25

Please provide your 2017 natural gas commodity charge per cubic metre.

Response:

The gas supply commodity charges in effect at January 1, 2017 for each of Union's operating areas are summarized in Table 1.

Table 1 - Summary of Gas Supply Commodity Charges

Line No.	Particulars	Gas Supply Commodity Rate (1) (cents/m^3)
1	Union South	16.0178
2	Union North West - Rate 01, Rate 10	11.7711
3	Union North West - Rate 20, Rate 100	11.4966
4	Union North East - Rate 01, Rate 10	16.3002
5	Union North East - Rate 20, Rate 100	15.9183

Notes:
(1) EB-2016-0334, Tab 2, Schedule 1.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 3, pp. 24 - 25

Does Union plan to include incremental ratepayer funded customer abatement activities into its 2018 compliance plan? If yes, please provide an approximate range of the budget level for those activities that Union believes is worth considering. If no, please fully explain and justify that position.

Response:

Please see the response at Exhibit B.Staff.14.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 3, pp. 24 - 25

Please make best efforts to provide the following estimated incremental DSM results based on the assumption that Union's 2017 DSM budget was increased by 25%:

a) Forecast TRC Test benefit/cost ratio;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

Please assume that the incremental budget would be spent as efficiently as possible. If possible, please assume that the incremental budget would be spent only in relation to customers whose emissions Union is responsible for under Cap-and-Trade legislation. Please make and state any additional assumptions as necessary.

If it is necessary to assume a date on which Union would have begun preparation and planning for the use of the incremental spending, please provide a response for two scenarios (a) the date that the draft regulations under the *Climate Change Act* were released (February 25, 2016); and (b) the date that the Cap-and-Trade Framework was released (September 26, 2016).

Response:

This request is onerous and not relevant to Union's 2017 Compliance Plan. Please refer to Union's 2015-2020 DSM Plan (EB-2015-0029) for 2017 forecast details.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence's ("ED")

Reference: Exhibit 3, pp. 24-25

Please make best efforts to provide the following estimated incremental DSM results based on the assumption that Union 2017 DSM budget was increased by 50%:

a) Forecast TRC Test benefit/cost ratio;
b) Forecast TRC Test net benefits;
c) Forecast TRC Test benefits;
d) Forecast TRC Test costs;
e) Forecast 2017 DSM savings (cubic metres);
f) Forecast lifetime DSM savings (cubic metres)
g) Forecast 2017 greenhouse gas emission reductions (tonnes);
h) Forecast lifetime greenhouse gas emission reductions (tonnes); and
i) Forecast 2017 program budgets.

Please assume that the incremental budget would be spent as efficiently as possible. If possible, please assume that the incremental budget would be spent only in relation to customers whose emissions Union is responsible for under Cap-and-Trade legislation. Please make and state any additional assumptions as necessary.

If it is necessary to assume a date on which Union would have begun preparation and planning for the use of the incremental spending, please provide a response for two scenarios (a) the date that the draft regulations under the *Climate Change Act* were issued (May 19, 2016); and (b) the date that the Cap-and-Trade Framework was issued (September 26, 2016).

Response:

This request is onerous and not relevant to Union's 2017 Compliance Plan. Please refer to Union's 2015-2020 DSM Plan (EB-2015-0029) for 2017 forecast details.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence's ("ED")

Reference: Exhibit 3, pp. 24 - 25

Please consider a scenario where the Board directs Union to achieve as many tonnes of incremental greenhouse gas emissions reductions as possible via incremental cost-effective 2017 DSM spending, including through the expansion of budgets for existing programs. Based on that scenario, please estimate:

a) The forecast incremental 2017 greenhouse gas emission reductions (tonnes);
b) The forecast incremental lifetime greenhouse gas emission reductions (tonnes);
c) The estimated cost of purchasing carbon allowances or credits for the tonnes of emission indicated in response to parts (a) and (b) of this interrogatory.

Please assume that the direction is issued by the Board on May 1, 2017. Please state all other assumptions and provide all underlying calculations.

Response:

This request is onerous and not relevant to Union's 2017 Compliance Plan. Please refer to Union's 2015-2020 DSM Plan (EB-2015-0029) for 2017 forecast details.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit 7, schedule 1

a) What are Union's total forecast cap and trade compliance costs for 2017?

b) What are Union's forecast 2017 costs for purchasing of carbon allowances and credits?

c) How many tonnes of emissions does Union forecast it will be responsible for in 2017?

d) What is Union's forecast average 2017 cost per tonne for the purchasing of carbon allowances and credits?

Response:

a) Please see Exhibit 3, Schedule 1, line 9, column i: $276,070,948.

b) The Climate Change Mitigation and Low-Carbon Economy Act, 2016 ("Climate Change Act") outlines prohibitions on the disclosure of certain information. These prohibitions are reflected in Section 4 of the OEB Cap-and-Trade Framework.[1]

   This question refers to information that has been classified as Strictly Confidential. In keeping with the legislation and with the best interests of ratepayers in mind, such information must remain Strictly Confidential in order to maintain the ability to effectively execute on Compliance Plans.

c) Please see Exhibit 2, Schedule 1, line 23: 15,597,229 tonnes CO_2e.

d) Please see Exhibit 3, Schedule 1, line 5, column h for Union's forecast average 2017 compliance cost per tonne: $17.70 CAD/tonne of CO_2e.

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[1] Climate Change Mitigation and Low-carbon Economy Act, 2016, S.O. 2016, CHAPTER 7 (Climate Change Act) and Regulatory Framework for Assessment of Costs of Natural Gas Utilities' Cap-and-Trade Activities (EB-2015-0363)

UNION GAS LIMITED
Deriviation of 2017 Cap-and-Trade Forecast Compliance Cost Unit Rates

Line No.	Particulars	Customer-Related GHG Emission Obligation	Facility-Related GHG Emission Obligation	Total GHG Emission Obligation
		(a)	(a)	(c) = (a + b)
1	Forecast Emissions (tCO2e) (1)	14,993,040	560,764	15,553,804
2	Weighted Average Forecast Price ($/tCO2e) (2)	17.70	17.70	17.70
3	Total Forecast Cost of Compliance Instruments ($000's) (line 1 x line 2 / 1000)	265,377	9,926	275,302
4	Total Forecast Cost of Abatement ($000's) (3)	-	-	-
5	Total Forecast Cost of Compliance ($000's) (line 3 + line 4)	265,377	9,926	275,302
6	Forecast Volumes (10^3m^3) (4)	7,997,879	289,882	
7	Compliance Cost Unit Rate (cents/m^3) (line 5/ line 6 x 100)	3.3181	3.4240	

Notes:
(1) Exhibit 2, Schedule 1, column (c), lines 21 and 22.
(2) Exhibit 3, Schedule 1, column (b), line 5.
(3) Exhibit 3, Schedule 1, column (c), lines 6 and 7.
(4) Exhibit 2, Schedule 1, column (c), lines 7 and 12.

Enbridge Gas Distribution

Impacts of Ontario's Proposed Climate Policy
Kick-off Meeting

July 7, 2015

Filed: 2017-03-17
EB-2016-0300
Exhibit I.1.EGDI.SEC.4
Attachment 1
Page 1 of 45

POTENTIAL IMPLICATIONS FOR EGD

1 NG consumption will need to decline 40% – 50% by 2030

- Residential, commercial, institutional NG consumption will need to decline by >40%
- Even with protection afforded industrial emitters consumption will need to decline by 20 – 30%
- No net increase in NG consumption for electricity generation

2 Electrification of transport and buildings

- Fuel switch from fossil fuels to electricity in transport (gasoline/diesel) and buildings (NG, oil) required to reduce demand (beyond DSM potential)
- Electricity demand (current and growth) will need to be met with non-fossil sources (nuclear, hydro, renewables)

3 Energy Efficiency / Demand Side Management

- Rate of energy efficiency needs to be dramatically increased (+5X current)
- Rate of DSM and incentives needs to be increased accordingly
- Deeper DSM targets will require deeper analytics and broader scope

POTENTIAL IMPLICATIONS FOR EGD

4 EGD will need to acquire \$300M–\$500M of allowance per year

- Starting in 2017/18.
- 350-400 bcf/yr = 20 Mt CO_2e = \$300M at \$15 / allowance. \$15/tCO2 = \$0.8/mmBTU
- For context the commodity price of the NG distributed is \$1.5B at \$4/mmBTU

5 EGD will need to build allowance acquisition infrastructure

- Accounting, finance, trading, analytics, offset/allowance sourcing, brokerage, MM&V, billing, customer relations, DSM, IT,… EGD's business will be better positioned than most. Opportunity?
- In depth Quebec, California knowledge

6 EGD will need to re-imagine infrastructure and business model

- Existing operations and plans for demand growth vs. 2030/2050 targets and stranded pipe/storage assets
- Combined impact of economy wide demand destruction as well as cost to deliver (including premature retirement of assets) and price of allowance on customers

UNCERTAINTY FOR EGD…

By 2030 natural gas demand in Ontario needs to be in the 600bcf/yr range.

1 WHEN (not IF) WILL DISTRIBUTORS BE COVERED?

Day 1 or Year 3? Will NG distribution companies be covered like Quebec or California?

Will there be allowance WHEN LDCs need it? How long between auction and pass through?

Can I pass carrying/admin costs through? Who decides (MOECC, OEB)?

2 HOW WILL SMALL INDUSTRY BE COVERED?

Will they get free allowance?

Who gets it (distributor has requirement to remit but industry must request gratis allocation)? How?

3 WHAT ABOUT EGD EMISSIONS?

Am I EITE – do I get FREE allowance?

Can I pass along the cost of compliance? All of it? Can I reduce?

Fugitives reporting? abatement?

4 WHAT IS THE ROLE OF NATURAL GAS?

Is natural gas a viable fuel circa 2030/2050? How viable – $5/mmbtu?

Industrial? Transport? Electricity? CHP?

What will -40% demand do to price to the commodity price? Price to customer?

5 WHAT IS THE ROLE OF EGD?

Do I know my customers MACCs? Does the ON/OEB?

How much DSM can fuel distributors deliver?

What would -40% DSM cost to deliver? How much does EGD want to do?

Can/should EGD offer compliance optimization solutions for large/medium/small customers?

If EGD doesn't will someone else?

6 WHAT DOES DE-CO_2 IZATION LOOK LIKE?

Less and more expensive NG, stranded assets?

DSM/EE/CDM, renewables, biogas, batteries, connected home, smart grid, smart / thermostats, customer engagement, building standards,…

UNCERTAINTY FOR Ontario…

The Provincial targets (2020, 2030, 2050) seem clear and consistent.

But not much else seems thought through – especially beyond 2020.

MOECC 6 month plan to post Draft regulation and 12-18 month to Final. California had 6 years.

1 NO DETAILS

We can make informed assumptions but we know little about Ontario's envisioned cap-and-trade system. Start date, targets, coverage, offsets, flexibility mechanisms…

2 NO MATH

We are missing all the analytics typically done before a cap is set and a trading system is designed. MACCs, detailed DSM / APs, existing and planned programs/standards…

3 NO PLAN

To date the MOECC proposes "immediate action" on expanded public transit, energy efficient buildings, and support for science research and technology to encourage breakthroughs.

4 LOTS OF MONEY

At \$15/tCO_2 over \$2B in revenue generated per annum – with a 2017, start \$7B by 2020. How will the \$s be spent? The Ontario Conservation First directive will deploy \$2B between now and 2020. OEB NG LDCs DSM = \$700M.

UNCERTAINTY FOR Ontario…

5 THIS IS NOT ABOUT LARGE EMITTERS

Large emitters will be allocated gratis. Electric and gas utility small/medium sized customers, personal and freight vehicles make up the majority of emissions and will likely wear the full cost of allowance.

6 ENERGY EFFICIENCY +DE-CO_2 IZATION

To meet emissions targets we will need to reduce the energy intensity of the economy (energy efficiency) and the GHG intensity of the energy that drives the economy (fuel switching, renewables etc…) or reduce the size of the economy.

7 IS THE SLOPE TOO STEEP

This is not about 2020 targets. The “straight-line” abatement trajectory from 2012-2050 runs through 100MtCO_2 circa 2030. Assuming the economy will grow modestly over the next 15 years, this would call for 65Mt to 75Mt of reductions;

- 50% electrification of the vehicle fleet.
- 40% improvement in energy efficiency in residential, commercial, institutional, industrial NG users or conversion to electric driven operations.
- 5000MW of nuclear base load replacement, new demand resulting from electrification and growth met with non-emitting dispatchable generation –no new NG fired units.
- Natural gas is not a viable transition fuel.
- Transfer of $100Ms to buy California allowance (assuming they are available).

Ontario
Executive Council
Conseil exécutif

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil exécutif, décrète ce qui suit :

WHEREAS the government adopted a policy of putting conservation first in its 2013 Long-Term Energy Plan, *Achieving Balance.*

AND WHEREAS it is desirable to achieve reductions in electricity consumption and natural gas consumption to assist consumers in managing their energy bills, mitigating upward pressure on energy rates and reducing air pollutants, including greenhouse gas emissions, and to establish an updated electricity conservation policy framework ("Conservation First Framework") and a natural gas conservation policy framework.

AND WHEREAS the Minister of Energy intends to issue a direction to the Ontario Power Authority to require that it undertake activities to support the Conservation First Framework, including the funding of electricity distributor conservation and demand management programs.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.2 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to establish conservation and demand management targets to be met by electricity distributors and other licensees.

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

Recommended ______________________
Minister of Energy

Concurred ______________________
Chair of Cabinet

Approved and Ordered MAR 2 6 2014
Date

____
Lieutenant Governor

O.C./Décret 467 / 2014

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, Minister of Energy, hereby direct the Ontario Energy Board (the "Board") pursuant to my authority under sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (the "Act") to take the following steps to promote electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM"):

1. The Board shall, in accordance with the requirements of this Directive and without holding a hearing, amend the licence of each licensed electricity distributor ("Distributor") to establish the following as the CDM target to be met by the Distributor:

   i. add a condition that specifies that the Distributor shall, between January 1, 2015 and December 31, 2020, make CDM programs available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of the Distributor's customer base, do so in relation to each customer segment in its service area ("CDM Requirement");

   ii. add a condition that specifies that such CDM programs shall be designed to achieve reductions in electricity consumption;

   iii. add a condition that specifies that the Distributor shall meet its CDM Requirement by:

      a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

      b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

      c) a combination of (a) and (b); and

   iv. add a condition that specifies the Distributor shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other Distributors upon request.

2. Despite paragraph 1, the Board shall not amend the licence of any Distributor that meets the conditions set out below:

   i. with the exception of embedded distributors, the Distributor is not connected to the Independent Electricity System Operator ("IESO") – controlled grid; or

   ii. the Distributor's rates are not regulated by the Board.

3. The Board shall establish CDM Requirement guidelines. In establishing such guidelines, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

i. that the Board shall annually review and publish the verified results of each Distributor's Province-Wide Distributor CDM Programs and Local Distributor CDM Programs and report on the progress of Distributors in meeting their CDM Requirement;

ii. that CDM shall be considered to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., <10MW) behind the meter customer generation. However, CDM should be considered to exclude those activities and programs related to a Distributor's investment in new infrastructure or replacement of existing infrastructure, any measures a Distributor uses to maximize the efficiency of its new or existing infrastructure, activities promoted through a different program or initiative undertaken by the Government of Ontario or the OPA, such as the OPA Feed-in Tariff (FIT) Program and micro-FIT Program and activities related to the price of electricity or general economic activity; and

iii. that lost revenues that result from Province-Wide Distributor CDM Programs or Local Distributor CDM Programs should not act as a disincentive to Distributors in meeting their CDM Requirement.

4. The Board shall establish a DSM policy framework ("DSM Framework") for natural gas distributors whose rates are regulated by the Board ("Gas Distributors"). In establishing the DSM Framework, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

   i. that the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

   ii. that the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

   iii. that Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

   iv. that Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

   v. that the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

   vi. that an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

vii. that DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

viii. that lost revenues resulting from DSM programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

5. By January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

6. Nothing in this Directive shall be construed as directing the manner in which the Board determines, under the *Ontario Energy Board Act, 1998*, rates for Gas Distributors or for Distributors, including in relation to applications regarding regional or local electricity demand response initiatives or infrastructure deferral investments.