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February 24, 2021

Ontario Energy Board
Attn: Christine E. Long, Registrar

By e-mail and electronic filing

Dear Ms Long

Re: EB-2020-0091 EGI IRP Proposal – GEC/ED T.U. J3.10(A)

Please find attached the transcript undertaking response of Mr. Chris Neme of Energy Futures Group.

Sincerely,

David Poch

Cc: all parties

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GEC Response to Energy Probe Undertaking

Question JT3.10(A)

To Provide a list of the inputs for the "TRC-plus" test.

Response:

Our sense from the discussion with Dr. Higgin during the technical conference is that he was interested in a hypothetical example to illustrate how the different inputs to the TRC+ test would be made. To that end, we have developed a hypothetical and will show how it applies to both a hypothetical demand response (DR) program as an IRPA and a hypothetical energy efficiency (EE) program as an IRPA.

For both of these examples, we assume peak demand of 90 units of gas, an existing maximum capacity of 100 units, and annual growth of 2 units. Thus, in this hypothetical, peak demand would be equal to the maximum existing capacity in five years. In other words, absent any demand-side investment, the capacity upgrade would be needed in five years. We also assume that the capacity addition will cost $25,000 and that a 4% real discount rate is used in the analysis. As Table 1 illustrates, that produces a net present value (NPV) cost for the infrastructure scenario of $20,548. That is the base case against which the two IRPA scenarios are compared.

Table 1: Cost of Infrastructure Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Cumulative Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Demand after DR	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$20,548
IRPA		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	**$20,548**
Other Benefits															
Avoided Energy Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Carbon Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other non-energy benefits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Net Cost		**$0**	**$0**	**$0**	**$0**	**$25,000**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$20,548**
Net Cost Difference vs. Infrastructure		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

With respect to DR, and as shown in Table 2, it is assumed that the maximum DR potential is 10 units, but that it would take ten years of marketing and offering of financial incentives to customers to ramp up to that level of DR capacity. It is further assumed that the utility has to pay a financial incentive to customers of $50 to achieve 1 unit of DR capacity, and that such payments are required each year (i.e., it is an annual payment required to keep customers enrolled in the DR program). It is also assumed that the utility must spend a fixed $25 per year, regardless of participation levels, to manage the DR program and market it to customers. For simplicity, it is assumed that there are no gas or electric energy savings that result from the DR program. As Table 2 illustrates, these assumptions lead to a total DR scenario cost of $19,151, or a cost savings relative to the infrastructure scenario of $1397.

Table 2: Cost of DR Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	0	0	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	120	130	140	
Costs															NPV
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
DR Incentives		$50	$100	$150	$200	$250	$300	$350	$400	$450	$500	$0	$0	$0	$2,100
DR Non-Rebate Costs		$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$0	$0	$0	$162
DR Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Other Benefits															
Avoided Energy Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Avoided Carbon Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Electricity savings		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Other non-energy benefits		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Total		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Net Cost		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Net Cost Difference vs. Infrastructure		$70	$120	$170	$220	($24,730)	$320	$370	$420	$470	$25,520	$0	$0	$0	($1,397)

With respect to EE, and as shown in Table 3, it is assumed that a geotargeted set of programs could generate 1 incremental unit of peak savings each year. Savings are assumed to last 15 years, so the theoretic maximum cumulative savings would be 15 units. However, the program is assumed to be stopped after 10 years because the infrastructure project cannot be deferred past year 10. It is further assumed that the utility pays a financial incentive of $250 to customers per unit of peak savings and that represents 50% of the cost of the efficiency measures – meaning customers would incur another $250 themselves. It is also assumed that the utility spends $75 per year to manage and market the programs. Unlike DR, EE provides substantial additional benefits in the form of avoided gas energy costs, avoided carbon taxes, avoided electricity costs (many gas efficiency measures also save electricity) and other customer non energy benefits. The hypothetical assumptions used to value these benefits, along with the other DR and EE assumptions, are presented in Table 4. As Table 3 shows, this hypothetical EE scenario has an NPV cost of $17,021, or $3527 less than the infrastructure option.

Table 3: Cost of EE Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	10	5	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	110	125	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
EE Incentives		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
EE Non-Rebate Cost		$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$0	$0	$0	$608
EE customer Costs		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
Total		$575	$575	$575	$575	$575	$575	$575	$575	$575	$25,575	$0	$0	$0	$21,553
Other Benefits															
Avoided Energy Costs		$20	$40	$60	$80	$100	$120	$140	$160	$180	$200	$200	$100	$0	$1,876
Avoided Carbon Taxes		$20	$39	$59	$78	$98	$117	$137	$157	$176	$196	$196	$98	$0	$1,835
Electricity savings		$5	$10	$15	$20	$25	$30	$35	$40	$45	$50	$50	$25	$0	$469
Other non-energy benefits		$4	$8	$11	$15	$19	$23	$26	$30	$34	$38	$38	$19	$0	$352
Total		$48	$97	$145	$193	$242	$290	$338	$387	$435	$483	$483	$242	$0	$4,531
Net Cost		$527	$478	$430	$382	$333	$285	$237	$188	$140	$25,092	($483)	($242)	$0	$17,021
Net Cost Difference vs. Infrastructure		$527	$478	$430	$382	($24,667)	$285	$237	$188	$140	$25,092	($483)	($242)	$0	($3,527)

Table 4: DR, EE and other General Assumptions

DR and DSM Assumptions	DR	DSM
Measure Life	1	15
Annual m3 saved	0	100
Annual kWh saved	0	50
Utility rebate	$50	$250
Customer measure cost	$25	$250
Utility non-rebate program cost	$20	$75

General Assumptions		
Real discount rate	4%	
Infrastructure Cost	$25,000	
Avoided Energy Cost ($/m3)	$0.20	
Carbon Tax $/tonne	$100	
Carbon Tax $/m3	$0.20	
Avoided electricity cost ($/kWh)	$0.10	
Customer non-energy benefits	15%	of non-CO2 benefits

The tables above collectively provide all the information needed to assess cost-effectiveness through the TRC+ test, as it is applied today in Ontario for DSM. The categories of impacts included in the TRC+ (again, as applied today in Ontario), along with the values from the hypothetical examples summarized above, are shown in Table 5 below. In this example, both the DR IRPA and EE IRPA would be cost-effective. However, the EE option produces greater net benefits (i.e., cost savings) and has a slightly higher benefit-cost ratio.

Table 5: TRC+ Test Calculations of Cost-Effectiveness

	DR	EE
Benefits		
Avoided Infrastructure Costs	$3,659	$3,659
Avoided Annual Gas Energy Costs	$0	$1,876
Avoided Gas Carbon Taxes	$0	$1,835
Avoided electricity costs	$0	$469
DSM Non-Energy Benefits Adder	$0	$352
Total	**$3,659**	**$8,191**
Costs		
IRPA Incentive Costs	$2,100	$2,028
Other IRPA Program/Admin Costs	$162	$608
Increased Utility O&M	$0	$0
Increased Carbon Taxes	$0	$0
Increase in other Fuel Costs	$0	$0
Increased Customer Costs	$0	$2,028
Total	**$2,262**	**$4,664**
Cost-Effectiveness Determination		
Net Benefits	**$1,397**	**$3,527**
Benefit-Cost Ratio	**1.62**	**1.76**
Non-Pipe Solution Cost-Effective?	**YES**	**YES**

Note that the TRC+ test, like all cost-effectiveness tests, should include all utility system impacts. However, the TRC+ test as currently applied in Ontario is missing a several potential benefits of energy efficiency and potentially other IRPA options. Specifically, it has not included the benefits of:

- market price suppression effects – reductions in demand for gas will lower the market clearing price for gas (even if the reduction is very small, the total value can be non-trivial when multiplied by total gas consumption by all of Enbridge's customers);
- option value – the modular nature of efficiency "buying time" to recalibrate peak load forecasts, which could lead to longer deferrals of even elimination of the need for an infrastructure upgrade; or
- risk mitigation – e.g., efficiency investments reducing customers' exposure to future gas price uncertainty.

All of those impacts should be added to future applications of the TRC+ test in Ontario.

Also, as explained in the EFG report in this proceeding, the analysis of cost-effectiveness of IRPA options such as DR and EE should include sensitivity scenarios, particularly with respect to potential impacts of more stringent climate policy impacts on gas demand and/or gas costs.