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July 31, 2018

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Patrick Wruck, Commission Secretary
By Web Posting

Dear Sir:

Re: FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application
~ BCUC Project No.1598939
BC Sustainable Energy Association and Sierra Club BC, Evidence

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Attached please find evidence by Phillip Raphals, Helios Centre, filed by BCSEA-SCBC in this proceeding.

Yours truly,

William J. Andrews

Barrister & Solicitor

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July 31, 2018

Evidence on the Fortis BC Rate Design Proposal

submitted to the
British Columbia Utilities Commission

on behalf of

the
BC Sustainable Energy Association
and Sierra Club BC

by

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1. INTRODUCTION AND SUMMARY

I have been asked by the BC Sustainable Energy Association (BCSEA) and Sierra Club BC (SCBC) to review aspects of the **2017 Cost of Service Analysis and Rate Design Application** ("RDA") of Fortis BC Inc. ("FBC"). In particular, I have been asked to address three issues:

- FBC's proposal to replace the current RIB rate with a flat rate,
- The proposed increase in the residential customer charge, and
- The proposed optional residential TOU rate.

The principle findings and conclusions are presented in the following section.

1.1. The Residential Conservation Rate

1.1.1. The RCR and the LRMC

The long-run marginal cost (LRMC) of new supply is the appropriate referent for the Tier 2 energy rate. However, FBC's LRMC cannot serve this function because it does not account for the additional investments in T&D infrastructure that load growth will cause or for line losses.

FBC estimates the Deferred Capital Expenditure for T&D at $79.85/kW-yr, which results in a residential DCE of $38.40 (2017$), based on the class' contribution to coincident peak. Using the residential class load factor of 21.4%, this results in an avoided cost of $20.49/MWh. Adding this to the power supply LRMC of $99.28 ($2017) and grossing up by 8.3% for line losses results in a full LRMC of **$129.71/MWh** — just 16.9% less than the current Tier 2 price of $156.17/MWh.

This power supply LRMC is based on portfolio A4 of the LTERP. In a recent decision, the Commission rejected this portfolio after 2024. The only additional resources required until then are DSM resources, based on the High DSM Scenario, with a UEC of $114 ($2015)/MWh. Should the Commission retain this value as a "Medium Run Marginal Cost" for energy and capacity, the full avoided cost would rise to of **$149.87/MWh**, which is just 4% lower than the current Tier 2 rate.

1.1.2. Conservation impact

FBC argues that the RCR is no longer necessary because most of the steps available to reduce its impact on bills have been taken. However, even if "much of the low-hanging fruit has been picked", there remains a significant potential of higher-cost measures, such as those involving efficient appliances or the building envelope.

FBC suggests that reducing the marginal price would only slow the uptake of the economic potential, but this is unsupported. To assume that lowering the marginal rate will have no effect on consumers' decisions with respect to these investments is to ignore the significance of price signals. For the consumer, an increase in the payback period may well make the difference between buying an energy-efficient water heater or investing in improved home insulation, or not.

Seen as a conservation measure, RIB rates compare very favorably to DSM programs in both cost and effectiveness. The 2014 RCR Report shows savings of 36 to 46 GWh —**roughly double the impact of all of FBC's DSM programs,** demonstrating that the RCR is an effective and inexpensive way to achieve energy conservation.

1.2. Increasing the residential customer charge

FBC is seeking to increase the residential customer charge from $16.05 to $18.70 per month (phased in over 5 years), as part of a proposal whereby the various customer classes would have their respective fixed costs recovered by the same percentage of fixed charges.

FBC acknowledges that it has not experienced negative impacts from fixed cost recovery through volumetric rates. It suggests that increasing self-generation could create equity challenges in the future but, given the very low penetration of distributed generation in the FBC service territory, now and in the foreseeable future, there is no reason for concern.

FBC sees an issue of intra-class equity, because the customer charge represents only 45% of residential customer-related costs, as defined in the COSA. 68% of these costs are capital costs, which in turn depend on the minimum system study. However, FBC's jurisdictional study shows that, for three asset categories representing almost two-thirds of all distribution plant, the percentage classified by FBC as customer-related is 48% to 88% higher than its peers. Absent a thorough investigation of the classification of distribution costs and of the adequacy of the minimum system study that underlies it, uncertainty remains as to the extent to which the current basic charge reflects the actual cost of service.

That said, "fair apportionment of costs among customers" is just one of the eight Bonbright Principles (#2), which must of course be balanced with the others. In its Decision G-156-10, the Commission explicitly determined that Bonbright Principle #3 (price signals that encourage efficient use) should trump Principle #2, specifically in the context of the basic charge.

In the author's view, the reasons that led to Commission to reject an increase to the Basic Charge in FBC's 2009 RDA remain relevant, and the reasons invoked by FBC in support of its proposed increase in the residential customer charge are not persuasive. This proposal runs counter to the principle of encouraging energy conservation and efficiency through the volumetric charge.

1.3. Optional TOU rate

The intention of the proposed optional TOU rates is to incent participating customers to shift consumption from higher cost to lower cost periods. Mandatory TOU rates are known to contribute to reducing demand. However, FBC has not advanced any evidence that optional TOU rates will have a similar effect.

Freeridership is a significant challenge with optional TOU rates. Depending on their consumption patterns, certain customers will be able to reduce their bills simply by switching to the TOU rate, without making any behavioural changes. In these cases, doing so will reduce FBC's revenues but not its costs, resulting in an additional cost burden for other customers. For the proposed optional TOU rate to be successful, it would have to cause a reduction in the utility's costs that is significantly larger than the revenue deficiency due to freeridership.

FBC estimates that, under current rates, 19% of residential customers would be better off under the TOU option without any change in behaviour, resulting in lost revenues of $9.4 million (an average of $34.86/customer/month) with no corresponding reduction in costs. However, should the Commission approve FBC's proposal to phase out its RCR, the number of customers in this situation would decline.

FBC has not presented estimates of the number of participants in the optional TOU rate, of the amount of load that would be displaced from peak to off-peak, of the lost revenue due to free-riders, or of the cost savings that would be expected to flow therefrom. It simply proposes to implement the optional rate on a service-territory-wide basis, and to judge its benefits based on reporting after three years.

A better approach would be to implement a pilot program, perhaps confined to a specific geographical area, or otherwise constrained, in order to develop a knowledge base regarding how customer behaviour would change under such a rate.

TOU rates are just one of a wide variety of Demand Response measures being used elsewhere. There is no indication that FBC thoroughly explored a full range of Demand Response options before deciding on the optional TOU approach.

If it did, it might conclude, as Hydro-Québec did, that Critical Peak Pricing and/or Critical Peak Credits would be a more effective way to reduce peak demand, with a lower risk of lost revenues due to free riders. It is recommended that FBC carry out a review of potential DR mechanisms, in order to determine the best path forward to reduce its peak demand.

Finally, it should be noted that, since the optional TOU rate would apparently have very different implications under the RCR than it would under a flat rate, there would be a benefit to reviewing these choices once the Commission's decision with respect to the flat rate proposal is known.

2. THE RESIDENTIAL CONSERVATION RATE

2.1. The RCR and the LRMC

FBC's Residential Conservation Rate (RCR), or Residential Inclining Block (RIB) Rate, was first adopted in 2012 as part of a strategy meant to respond to various legislative and policy imperatives, defined among others by the Clean Energy Act and the 2007 Energy Policy.

> FortisBC states it believes that its RIB rate proposal is "one component within a comprehensive demand reduction strategy that helps the Commission and the Province fulfill conservation goals."[1]

Now, FBC seeks to return to a flat rate, asserting that there is no cost basis for an RCR, and that "any combination of rates contained in an RCR can be considered arbitrary when viewed from a cost-causation perspective"[2]. In particular, FBC claims that there is no cost basis for the Tier 2 price, increases to which are based on the residual after general and rebalancing rate increases are applied to Tier 1. It further asserts that the Tier 2 rate is not based on the long run marginal cost (LRMC),[3] affirming that "any reference to LRMC as a 'comparator' for the Tier 2 rate is of limited significance and has no practical application". [4]

FBC acknowledges that LRMC should, in theory, provide a price signal for conservation that is linked to the long run costs that will be avoided if the conservation is undertaken.[5] However, it insists that the Tier 2 rate of the RCR has never been set with reference to the LRMC,[6] in that the Pricing Principle proposed by FBC and accepted by the Commission in the FBC 2011 RIB Rate

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[1] Decision and Order, G-3-12, page 6.

[2] Exhibit B-1, Application, s. 6.1.5; Exhibit B-8, BCUC 1.38.12

[3] Exhibit B-24, BCSEA 2.8.2.

[4] Ibid.

[5] Exhibit B-8, BCUC 1.38.1

[6] Ibid.

proceeding determines Block 2 as a residual, after assigning all revenue requirement increases to Block 1.[7]

While this Pricing Principle did not make any association between the Block 2 price and the long-run marginal cost, the Commission did. In its Decision, the BCUC clearly indicated its intention that **"the long-run marginal cost of new supply continues to be the appropriate referent for the Block-2 energy rate."**[8]

While the BCUC, in its information requests, had explored the possibility of capping the Tier 2 rate at the LRMC, FBC argued against doing so.[9] The BCUC did establish a link between Tier 2 and the LRMC, but it declined to cap the Block 2 rate at the LRMC — not for the reasons proposed by FBC, but because the company's estimate of LRMC failed to include delivery costs:

> While the Panel considers the most appropriate referent to be the cost of acquiring energy through new resources, we note that all of the above marginal costs represent only the cost of acquiring the energy. Thus, there is ambiguity between the LMRC as defined by FortisBC and the true long-run marginal cost of new supply to the customer. The Block 2 rate is a delivered rate, while the LRMC is a cost of acquisition – it only relates to the cost of procuring energy but does not include the LRMC of transporting that energy to customers through transmission and distribution networks. FortisBC estimates the LRMC at $125.80 per MWh, or 12.58 cents per kWh, which includes line losses of 11 percent, but does not include other delivery costs. FortisBC has provided no further information about the cost to deliver this additional energy acquired from market purchases or new resources. …
>
> Thus, the Panel is satisfied that this Block 2 rate is below the actual delivered LRMC. Because of the uncertainty of the actual LRMC, the Panel does not agree that the Block 2 rate be capped at this time. [10] [underlining added]

To remedy this defect, the Commission directed FBC:

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[7] Decision and Order G-3-12, pages 41-43. The threshold was apparently treated as fixed.

[8] Ibid., p. 40, bold in the original.

[9] FBC 2011 RIB Rate Application, FBC Final Submission, Pages 8-9.

[10] FBC 2011 RIB Rate Application, BCUC Decision and Order G-3-12, p. 41.

> **… to provide an update of the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the reporting to be submitted in 2014.**[11] [bold in original]

The 2014 RCR Report did not however provide this information. Rather, it stated:

> FBC intends to provide an in-depth analysis of LRMC in its next Long-Term Resource Plan and Long Term DSM plan expected to be filed in 2016, for which consultation is currently underway. Without the benefit of the detailed work being undertaken as part of that process, it would be premature to file anything substantive that differs from the LRMC discussed in recent regulatory submissions.[12] [underlining added]

In fact, as discussed in the next section, the LTERP also declined to propose a value for "the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer". The Commission's conclusion in G-3-12 to the effect that LRMC should not be viewed as a cap on the Tier 2 rate thus remains undisturbed.

FBC acknowledges that if marginal costs are higher than embedded costs, a rate structure that reflects the marginal cost can lead to more economically efficient levels of consumption.[13] It also acknowledges that, in theory, "reference to LRMC in setting a higher second block rate, as in the RCR, is to provide a price signal for conservation that is linked to the long run costs that will be avoided if the conservation is undertaken."[14]

FBC further acknowledges that its long run marginal cost (LRMC) is higher than FBC's current embedded cost of generation, but affirms that its current Tier 2 rate is higher than both.[15] More

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[11] Ibid., p. 41.

[12] FBC, RCR REPORT JULY 1, 2012 TO JUNE 30, 2014, page 23 (Exhibit B-12, BCSEA Attachment 1.2, round 1).

[13] Exhibit B-22, AMCS-RDOS 2.1.2.

[14] Exhibit B-8, BCUC 1.38.2.

[15] Exhibit B-22, AMCS-RDOS 2.1.7.

specifically, it affirms that the Tier 2 rate is 58% higher than the long run marginal cost of 9.9 cents (2017$) per kWh.[16]

In the following section, we will look more closely at FBC's LRMC and its relationship to the Tier 2 rate.

2.1.1. FBC's Long Run Marginal Cost

FBC identifies its Long Run Marginal Cost (LRMC) at the point of interconnection as $96 (2015$), or $99.28 ($2017).[17] This value is based on portfolio A4 of the 2016 LTERP. (The implications of the Commission's decision earlier this year with regard to portfolio A4 will be addressed in the next section.)

FBC acknowledges that "the Tier 2 rate is a delivered rate while the LRMC is stated at the point of interconnection to FBC's system and the two rates are not directly comparable".[18]

This lack of comparability is based primarily on two factors. The LRMC as stated in the LTERP does not account for the additional investments in T&D infrastructure that load growth will cause, nor does it account for line losses.

With respect to the avoided cost of additional transmission and distribution infrastructure, FBC indicates that it has no estimate of marginal T&D costs for serving a residential customer.[19] It

[16] Exhibit B-22, AMCS-RDOS 2.1.5.

[17] Exhibit B-8, BCUC 1.38.2; Exhibit B-22, AMCS-RDOS 2.1.4; Exhibit B-11, BCOAPO 1.42.1, note 10. This value includes both energy and capacity (Exhibit B-11, BCOAPO 1.42.1).

[18] Exhibit B-22, AMCS-RDOS 2.1.5; Exhibit B-23, BCOAPO 2.76.1.

[19] Exhibit B-11, BCOAPO 1.42.2.

does however use a T&D Deferred Capital Expenditure of $79.85/kW-yr to estimate T&D costs that are avoided by demand side management (DSM) programs.[20]

In FBC's view, the LRMC of power supply and the Deferred Capital Expenditures relating to T&D infrastructure are two separate values that are expressed in different units and that apply to separate parts of the system. It says the two values cannot be readily combined and, if summed together, would not be consistent with the established definition of Long Run Marginal Cost.[21]

While FBC has not adopted a methodology to combine power supply and infrastructure costs, other utilities have. Since 2002 the Régie de l'énergie (the Quebec Energy Board) has routinely established the avoided costs of Hydro-Québec Distribution (HQD), taking into account avoided T&D investments. The primary purpose of these avoided costs has been to determine the cost-effectiveness of proposed energy-efficiency programs, but they are also used for other purposes, including evaluating rate structures.[22]

Avoided capital cost expressed in $/kW/yr can be converted to a unit energy cost expressed on a per-kWh basis as follows:

Avoided cost in $/kWh = (avoided cost in $/kW/yr) / (8760 hrs/yr * load factor)[23]

Thus, if the load factor were 100%, the annual average avoided capital cost per kW would have to be divided among the 8760 hours of the year in order to recover the annual demand cost on a per-kWh basis. When the load factor is lower than 100%, the annual cost must be divided among a smaller number of kWh.

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[20] Ibid.

[21] Exhibit B-23, BCOAPO 2.76.1.

[22] Hydro-Québec Distribution, Présentation de la Méthodologie de Calcul des Coûts évités, Régie de l'énergie, file R-3610-2006, HQD-15, doc. 2, Annexe A, page 23, slide 39, at http://www.regie-energie.qc.ca/audiences/3610-06/Requete3610/hqd_15_02_annexe_a_PGEE.pdf

[23] Ibid., page 19, slide 30.

In its energy efficiency program, Hydro-Québec applies this method to determine avoided costs specific to individual end uses. However, it can also be applied on a higher level, using the relevant load factor.

FBC points out that the Deferred Capital Expenditure (DCE) is a high-level system-wide estimate for the marginal costs of transmission and distribution, and does not separate out a DCE value for the residential or any other customer class.[24] One plausible approach for allocating DCE among customer classes would be in relation to their contribution to the coincident peak (CP). According to the COSA, the residential class in 2016 accounted for 45.7% of CP, and in 2017 for 47.3%.[25] Using the average of these two values (46.5%) results in a preliminary estimate of $38.40/kW-yr (2017$) for the residential portion of DCE.

Again according to the COSA, the global load factor of the residential sector for both 2016 and 2017 is 21.4%.[26]

Applying the formula set out above to FBC's residential sector, results in the following calculation:

Avoided cost T&D = $38.40/kW-yr / (8760 hrs/yr * 21.4%)

= $38.40/kW-yr / 1873.9 hrs/yr

= $0.02049/kWh

= $20.49/MWh

[24] Ibid.

[26] Exhibit B-2, FortisBC COSA 2017, "Load" tab, cell C246/B246 (2016) and cell C579/B579 (2017).

[26] Ibid., "Load" tab, cells C130 and C463.

Using this method suggests an additional avoided cost for T&D infrastructure growth for the residential class of $20.49/MWh. Thus, the combined LMRC, taking into account both power supply and infrastructure costs would be $99.28 + $20.49 = $119.77/MWh, before losses.

FBC estimates transmission and distribution losses at 8.3%.[27] **The full avoided cost is therefore:**

$119.77/MWh * (1 + 8.3%) = $129.71/MWh

To summarize: In Decision G-3-12, the Commission directed FBC "to provide an update of the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer". As FBC has still not done so, we have calculated a preliminary estimate of FBC's full LRMC using its data, standard methods and reasonable assumptions. **The resulting value, based on the A4 portfolio, is $129.71/MWh — only 16.9% less than the Tier 2 energy price of $156.17/MWh.**[28]

2.1.2. LMRC in light of FBC's 2016 LTERP

FBC explains that the LRMC is based on a specific resource portfolio. For each resource portfolio analyzed in its LTERP, FBC presented the corresponding LRMC.[29] The LRMC of $96/MWh (2015$) referenced in the application corresponds to resource portfolio A4, the one preferred by FBC in the 2016 LTERP.

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[27] Exhibit B-11, BCOAPO 1.42.1.

[28] Exhibit B-8, BCUC, 1.38.3.

[29] FBC, 2016 LTERP Application, Fig. 9-7, page 125, at http://www.bcuc.com/Documents/Proceedings/2016/DOC_48380_B-1_FBC-2016-LTERP_LT-DSM-Plan-App.pdf.

In Decision and Order G-117-18, the BCUC accepted FBC's proposed long-term resource portfolio A4, but only through 2024. It explicitly rejected the portfolio A4 for the years beyond 2024, finding it not to be in the public interest (p. 19). While the resources required through 2024 were identical in all four portfolios presented, the choice of portfolio A4 — the third most expensive of the four — was based in large part on FBC's self-sufficiency objective, which the Commission rejected. The Commission deferred study of the post-2024 resource options for FBC's next LTERP.[30]

Given that FBC's LRMC figures discussed above are based on its LTERP filing, this Commission decision must inevitably affect the LRMC value. To evaluate this impact, we have to look at the resource portfolio through 2024, which was accepted by the Commission, and ignore the portfolio costs after that year, which were rejected.

According the LTERP application, the energy and capacity load-resource balances (LRBs) after DSM show no additional resource requirements before 2024. The only additional resources required prior to 2024 are apparently DSM resources, based on the High DSM Scenario preferred by FBC and approved by the Commission.[31]

In Table 8-1 of the LTERP, FBC identifies the UEC of this High DSM resource option at $114 ($2015)/MWh, substantially higher than the $96 associated with the full A4 portfolio. It would thus appear that the resource cost — and hence the LRMC — for the period for which the portfolio was accepted (through 2024) would be considerably higher than the LRMC for the entire planning period.

While this inference was not explicitly drawn by either FBC or the Commission, the implication of the decision in G-117-18 to accept the recommended portfolio plan only through 2024 is to

[30] 2016 LTERP Decision and Order G-117-18, page 19 of 27.

[31] FBC, LTERP Application, pages 101 and 102, at http://www.bcuc.com/Documents/Proceedings/2016/DOC_48380_B-1_FBC-2016-LTERP_LT-DSM-Plan-App.pdf.

increase the unadjusted LRMC (albeit calculated over a shorter period) to $114 (2015$). The DCE adder of $20.49 (2017$) remains unchanged.

The resulting calculation would be as follows:

LRMC (power supply):		$114.00 (2015$)/MWh
LRMC (power supply):		$117.90 (2017$)/MWh
+ DCE adder	+	$ 20.49/MWh
Total before line losses:		$138.39/MWh
TOTAL WITH 8.3% LOSSES		**$149.87/MWh**

This value of $149.87/MWh is just 4% lower than the current Tier 2 rate of $156.17/MWh.

It would thus appear that, based on the foreshortened resource portfolio approved in G-117-18, the current Tier 2 rate is only slightly higher than the LMRC.

2.1.3. Conclusions

The Commission concluded that LRMC should not be seen as a “cap” for the Tier 2 rate, primarily because it failed to take losses and marginal T&D investments into account. Once this is done, it would indeed be problematic to set a Tier 2 rate substantially higher than this adjusted LRMC. It thus appears that the Tier 2 rate should be adjusted slightly downwards, to reflect the adjusted LRMC.

If the Commission accepts the LRMC figure developed in the previous section, based on a foreshortened resource portfolio, only a minor adjustment would appear to be necessary. If, on the other hand, the Commission retains the LRMC derived from portfolio A4, or a value similar to it, the Tier 2 price would need to be reduced by 15-20% in order to remain in line with the LRMC.

In order to get an idea of what such an RCR would look like, it is useful to refer to FBC's response to a Commission IR, in which FBC presented 18 distinct combinations of the four parameters of the RCR rate, each of which would allow it to recover its revenue requirement.[32] Sorting these 18 combinations by the Tier 2 Rate produces the following table[33]:

	Customer charge	Tier 1	Tier 2	threshold
Option 7(ii)	18.7	0.1085	0.1337	800
Option 8(ii)	18.7	0.108	0.1347	800
Option 5(ii)	18.7	0.1075	0.1356	800
Current Option 8	18.25	0.108	0.136	800
Current Option 7	17	0.1085	0.139	800
Option 7(i)	16.05	0.1085	0.1423	800
Option 4(ii)	18.7	0.1077	0.143	1,000
Option 8(i)	16.05	0.108	0.1432	800
Current Option 5	16.05	0.1075	0.1442	800
Option 5(i)*	16.05	0.1075	0.1442	800
Option 3(ii)	18.7	0.107	0.1449	1,000
Option 6(ii)	18.7	0.1022	0.1457	800
Current Option 4	18	0.1077	0.146	1,000
BCUC 1.38.12	18.7	0.10175	0.14652	800
Current Option 6	18	0.1022	0.148	800
Option 4(i)	16.05	0.1077	0.1541	1,000
Option 6(i)	16.05	0.1022	0.1542	800
Current Option 3	16.05	0.107	0.15617	1,000
Option 3(i)*	16.05	0.107	0.15617	1,000

The first option listed — Option 7(ii) — has a Tier 2 rate of 13.37¢/kWh, just 3% higher than the full avoided cost of $129.71/MWh derived in section 2.1.1. One can thus assume that the corresponding Tier 1 rate would be only slightly greater than the 10.85¢/kWh found in that same variant, and that the ratio Tier 2/Tier 1 would be only slightly lower than the 23% premium found therein.

[32] Exhibit B-8, BCUC 1.38.8.

[33] We have also added as a 19th variant the one described in Exhibit B-8, BCUC 1.38.12.

We should also note that this Option 7(ii) includes increasing the Customer Charge to the level proposed in the Application ($18.70/month). If the Commission were to fix the Tier 2 rate at the full avoided cost of $129.71/MWh and the Customer Charge at the current level of $16.05, the Tier 1 rate would have to increase to make up the lost revenue. The result would be to diminish the ratio between the Tier 2 and Tier 1 rates even further, while still retaining the conceptual structure of an RCR.

Even with this adjustment, Tier 2 would remain greater than Tier 1. If, however, at the end of the day, this approach resulted in the two rates being equal — and hence numerically identical to a flat rate— this would still be preferable to a return to a flat rate, since, should LRMC increase in the future, it would be a simple matter to adjust the RCR to reflect those new avoided costs, without having to recommence the rate design process from scratch.

2.2. Conservation Impact

Despite acknowledging that the RCR was effective in encouraging energy conservation,[35] FBC argues that the RCR is no longer necessary because most of the steps available to reduce its impact on bills have been taken. It adds:

> This conclusion is also consistent with the assumption made during the original 2011 RIB process where the total rate-related conservation impact was assumed to be fully realized over 5 years, or by 2017. [note omitted][36] [underlining added]

However this assumption was merely a convenience adopted to respond to a BCUC IR in the 2011 FBC RIB proceeding:

> For the purpose of estimating the RIB savings, the 1.9% conservation impact from the Company's proposed option was assumed to be fully realized by 2017, with 0.2217% occurring in 2012. The Company notes that these assumptions were made in order to respond

[35] Exhibit B-22, AMCS-RDOS 2.3.1 through 2.3.3.

[36] Exhibit B-1, Application, page 72.

> to the original question and in practice; it has no method for determining how much of the estimated savings would result in any given year.[37] [underlining added]

Thus, while the assumption that the total rate-related conservation would be realized over five years was indeed made by FBC "during the original 2011 RIB process", it was unsupported at the time, and should be given no weight today.

FBC claims that much of the low-hanging fruit has been picked, defining "low hanging fruit" as:

> the obvious or easy things that can be most readily done or dealt with in achieving success or making progress toward an objective. In the context of conservation measures, examples are changing the thermostat settings in a residence and changing to energy efficient lighting.[38] [underlining added]

These are either no-cost (behavioural) or low-cost measures. However, the impact of a substantial price signal is more likely to be felt with regard to more expensive measures which must be amortized over several years before they are cost-effective, such as those involving efficient appliances or the building envelope.

FBC admits that there remains an economic potential for conservation in the residential sector, but it does not have the analytical tools to quantify it. It adds:

> Payback acceptance curves indicate that a shorter payback period, assuming the customer acts rationally and the measure savings are Tier 2, will result in a faster uptake of the economic potential. This is not to say that all of the potential won't be achieved with a flat rate over time, just that it may take longer to do so.[39]

The suggestion that reducing the marginal price would only slow the uptake of the economic potential is not supported. For the consumer, an increase in the payback period may well make

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[37] 2011 FBC RIB Application (Exhibit B-12), BCUC IR 2.3.1.1, at http://www.bcuc.com/Documents/Proceedings/2011/DOC_28665_B-12_FBC-Responses-BCUC-IR-2.pdf.

[38] Exhibit B-22, AMCS-RDOS 2.5.1.

[39] Exhibit B-24, BCSEA 2.17.5.

the difference between buying an energy-efficient water heater or investing in improved home insulation, or not.

To give a few examples, the following table identifies the incremental cost of the high-efficiency options for several key measures:[40]

Table 2. Incremental Costs of Selected High-Efficiency Measures

Measure	Base Measure Cost	Efficient Measure Cost	Difference	Incremental savings per unit (kWh/yr)	Technical Potential (GWh)
Heat Pump Water Heater 2.0 EF	$1000	$1950	$950	1436	20.6
Clothes Dryer	$562	$773	$211	283	20.7
Ceiling Insulation (R-49) (single family attached or detached)	$0	$1189	$1189	4000-4300	15.9

Table 2 illustrates several measures with a substantial technical potential and incremental savings, but which also require substantial additional investments and so cannot be considered "low hanging fruit". To assume that lowering the marginal rate will have no effect on consumers' decisions with respect to these investments is to ignore the significance of price signals.

FBC also argues that, to the extent that a potential for conservation exists among lower use customers, the price signal below the current Tier 2 threshold will become stronger as the flat rate is phased in.[41] However, the increase in Tier 1 rates will only result in an increased price

[40] Sources: (a) Appendix A2, British Columbia Conservation Potential Review for FortisBC by Navigant, January 18, 2017, tab "Measure Assumptions – Year 2016", columns M, N, O and S; (b) Technical Potential from FBC 2016 LT DSM Plan, Appendix A, FBC CPR, Fig. 4-12, page 608 of pdf) at http://www.bcuc.com/Documents/Proceedings/2016/DOC_48380_B-1_FBC-2016-LTERP_LT-DSM-Plan-App.pdf.

[41] Exhibit B-24, BCSEA 2.17.5.

signal when there is no consumption at all in Tier 2. As long as there is even a small amount of Tier 2 consumption, it is the Tier 2 price that is on the margin. Thus, for any bill with any Tier 2 consumption, the flat rate would provide a weaker price signal than the RCR.

FBC indicated that it has not estimated the increase in consumption expected to result from returning to a flat rate. For the two years ending in 2014, even though only 38.2% of residential consumption was in Tier 2, **77.8%** of customers had at least one bill with consumption in Tier 2.[42] Unfortunately, to the best of our knowledge, the percent of bills with no Tier 2 consumption at all has not been provided. Insofar as there are more bills with at least some Tier 2 consumption than without any, increased usage in Tier 2 would likely not be offset by decreased usage in Tier 1.

FBC also argues that "the majority of savings associated with the RCR are related to persistent DSM measures that have already been installed".[43] However, while FBC claims that much of the low hanging fruit has been picked, it makes no such claims about the more persistent DSM measures with the largest potential in the residential sector, which include[44]:

- smart thermostats (49.6 GWh),
- ENERGY STAR home (24.9 GWh),
- efficient clothes dryers (20.7 GWh),
- Heat Pump Water Heater 2.0 EF (20.6 GWh),
- Energy Star Television (20.5 GWh), and
- Ceiling Insulation (15.9 GWh).

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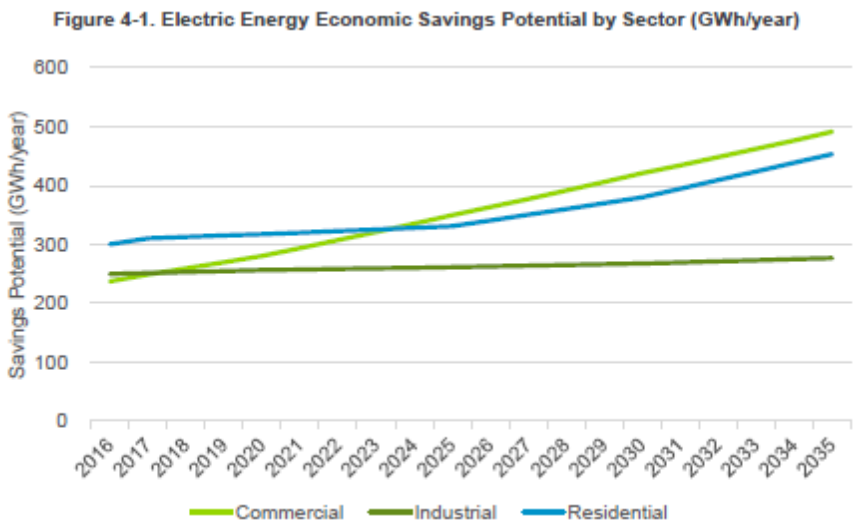
[42] Exhibit B-12, Attachment 1.2, FBC Residential Conservation Rate Information Report For the Period July 1, 2012 to June 30, 2014 (November 28, 2014), Table 2-3, page 19, pdf page 96.

[43] Exhibit B-24, BCSEA 2.16.3.

[44] FBC 2016 LTDSM Plan, Appendix A (Navigant – BC Conservation Potential Review), Fig. 4-12, page 608 of pdf, at http://www.bcuc.com/Documents/Proceedings/2016/DOC_48380_B-1_FBC-2016-LTERP_LT-DSM-Plan-App.pdf.

These are all persistent measures which require a substantial initial investment, none of which could be characterized as "low hanging fruit". There is no reason to believe that the potential for these measures has been exhausted.

FBC's 2016 long-term DSM plan indicated an energy savings potential for the residential sector of over 300 GWh/yr increasing steadily after 2024 to over 400 GWh/yr, as shown in the blue line (starting at 300 GWh/yr and inclining to about 450 GWh/yr) in the following graph[45]:



On average, 91% of FBC's residential technical potential was found to be cost-effective, based on the relationship between the total resource cost and avoided costs.[46] These measures remain cost-effective, from a TRC perspective, regardless of the electricity rate. But their penetration does depend on rates, and with a flat rate well below the full LRMC, penetration of the higher cost measures can be expected to diminish without DSM program support.

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[45] FBC 2016 LTERP and LTDSM Plan proceeding, Exhibit B-1, Vol.2, Appendix A, FBC Conservation Potential Review (Navigant), pdf p. 600, at http://www.bcuc.com/Documents/Proceedings/2016/DOC_48380_B-1_FBC-2016-LTERP_LT-DSM-Plan-App.pdf

[46] Ibid., pdf p. 599 and 601.

Seen as a conservation measure, RIB rates compare very favorably to DSM programs in both cost and effectiveness. The actual RCR savings for the year 2011-2012 were estimated as follows in the 2014 RCR Report, based on measured elasticities[47]:

Table 3-2: Updated estimate of RCR Savings*

	Measured Amount	Upper End
Tier 2 Elasticity	-0.16	-0.20
% Price Differential	28%	28%
Resulting % Savings on Tier 2	4.4%	5.7%
2011-2012 GWh in Tier 2	818.3	818.3
Estimated GWh Savings	36.2	46.3

* Reproduced from Table A-5 of the EES Report

The report states:

> These results show a range of savings from 36 to 46 GWh. …
>
> When compared to the overall system rather than just the residential Tier 2 GWh, the estimated savings are in the range of 2.6% to 3.3% of total system energy. For comparison purposes, the system-wide savings expected from FBC's DSM programs are 14 GWh (1.0%) for 2014 and 22 GWh (1.6%) for 2015.[48] [underline added]

In other words, **FBC indicated that the estimated conservation impact of the RCR was roughly double the impact of all of its DSM programs.** Thus, based on these admittedly incomplete figures, the RCR appears to be an effective and inexpensive way to achieve energy conservation.

[47] Asked to update these elasticities, FBC responded that it "has not measured the elasticity factors since the 2014 RCR report and cannot provide an update to the table" (Exhibit B-24, BCSEA 2.16.1). However, it indicated that it "would not expect to see a large increase beyond the amount measured in 2014" (Exhibit B-24, BCSEA 2.16.2).

[48] Exhibit B-12, Attachment 1.2, 2014 RCR Report, page 20 (pdf page 101).

3. INCREASING THE RESIDENTIAL CUSTOMER CHARGE

FBC is seeking to increase the residential customer charge from $16.05 to $18.70 per month (phased in over 5 years). This is part of FBC's proposal that the various customer classes would have their respective fixed costs recovered by the same percentage of fixed charges to volumetric charges. FBC targets recovering 65% of demand-related costs and 55% of customer costs through fixed charges.

> While there is no standard or "correct" level at which to set the recovery percentages, FBC believes that a more consistent level of recovery across the rate classes is desirable from an equity standpoint, would better reflect the costs derived in the COSA and would begin to address the challenges that may emerge as customers gain the ability to reduce their contribution to the fixed costs of the utility system.[49]

FBC acknowledges that it has not experienced negative impacts from fixed cost recovery through volumetric rates. During the PBR term, revenue variances are captured in the annual flow-through mechanism, and, even without that mechanism, any impact of revenue variances would tend to be transitory, since volumes and revenues are generally re-forecast every one to two years.[50]

FBC's primary argument advanced in favour of this change is one of intra-class equity. FBC suggests that recovering a significant portion of fixed costs through volumetric rates results in under-recovering fixed costs from low-use customers and over-recovering them from high-use customers in the same class.[51]

FBC also presents an argument that recovering some portion of fixed costs through volumetric rates could create challenges in the future due to increasing self-generation. It makes reference to this as a "contributing factor" to its proposals regarding fixed costs:

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[49] Exhibit B-12, BCSEA 1.2.2

[50] Exhibit B-12, BCSEA 1.13.1

[51] Ibid.

> NM programs are emblematic of why fixed cost recovery, which has historically been below COSA-indicated amounts, is becoming an issue of growing concern for utilities. The increasing ability of customers to reduce contributions to fixed costs is a contributing factor to FBC proposals in this area.[52]

However, given the very low penetration of distributed generation in the FBC service territory, there is little reason for this concern.

In the FBC service territory, total installed net metering generation capacity amounts to just over 2MW DC.[53] Assuming that most of this generation is solar, with average generation of 1150 kWh/kW/yr[54], total NM generation in the FBC service area would be around 2400 MWh/yr, less than 0.075% of FBC's total electricity sales of 3282 GWh/yr.

With penetration at such low levels, it would clearly be inappropriate to modify rate policy based on net metering. While NM installed capacity has been increasing geometrically over the last several years, several more years of such growth would be required before the NM installed capacity reached a level where its effect on fixed cost recovery would be even perceptible.

In its arguments regarding customer charges, FBC treats both demand costs and customer costs as fixed costs that it affirms should be recovered through fixed charges (rather than volumetric charges). However, high-use residential customers generally require more kW at peak, as well as more kWh during the year, than their low-use counterparts. There is thus nothing particularly problematic in recovering demand costs through volumetric rates, from an intra-class equity point of view.

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[52] Exhibit B-12, BCSEA IR 1.3.1

[53] Exhibit B-12, BCSEA IR 1.5.1.

[54] Estimated from NRCan's Municipality database of photovoltaic (PV) potential and insolation, at http://www.nrcan.gc.ca/18366. A British Columbia solar map can be found at https://solarpanelpower.ca/solar-power-maps-canada/#british-columbia

The same cannot be said of customer costs. To the degree that costs related solely to the number of accounts are recovered through volumetric charges, there is a potential for intra-class subsidization.

According to FBC's COSA, residential customer-related costs amount to $49.3 million, or $35.60 per customer/month, broken down as follows:[55]

	Residential	
	Customer-Related Costs	Costs per Customer
Distribution	$5,606,873	$4.04
Customer Service, Accounts & Sales	$5,186,142	$3.74
Administrative & General	$2,175,934	$1.57
Depreciation	$14,884,533	$10.73
Property Taxes	$3,987,090	$2.87
Return (Debt Component)	$8,647,233	$6.23
Return (Equity Component)	$10,122,109	$7.30
Income Taxes	$2,334,200	$1.68
Other Revenues	-$3,563,723	-$2.57
	$49,380,392	$35.60

Of the $35.60 per customer monthly costs, $24.26 (68%) consists of capital costs (depreciation plus return), presumably based on assets classified as customer-related, in accordance with the minimum system study.

FBC's jurisdictional study shows that utilities vary widely in the way they classify certain distribution system assets between customer and demand. The proportion of these assets classified by FBC as customer-related is systematically higher than those of its peers, and sometimes dramatically so, as seen in the following table.[56] (The table identifies the percent of

[55] Exhibit B-24, BCSEA 2.1.1.

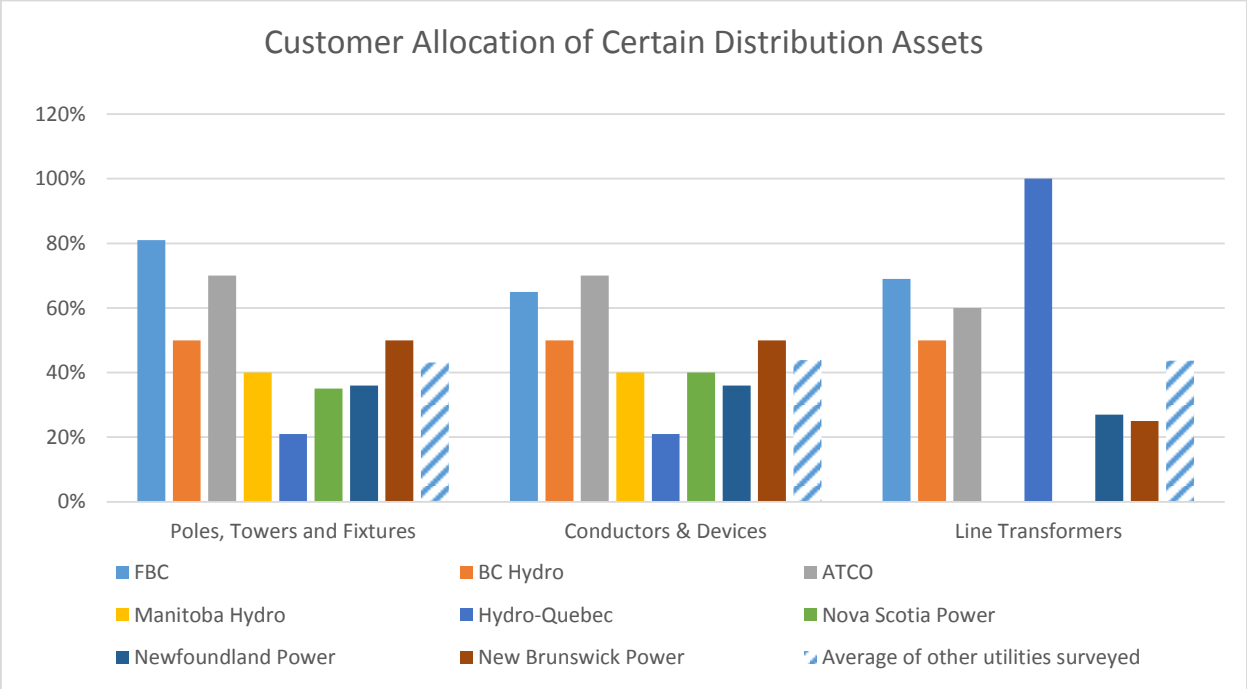
[56] FBC values from Exhibit B-1, Application, Table 5-7, page 49. (These values are lower than those found in the COSA, tab "Rate Base", cells I67, I68 and I71, which appear to be in error.) Other values from Exhibit B-21, BCUC 2.116.1. Fortis Alberta is omitted from this summary table, because it allocates directly by class, skipping the step where costs are split between demand and customer.

the cost of each type of asset that is classified as customer-related; the remainder is classified as demand-related.)

Percent of Certain Distribution Assets Classified as Customer-Related

	FBC	BC Hydro	ATCO	Manitoba Hydro	Hydro-Quebec	Nova Scotia Power	Newfoundland Power	New Brunswick Power
Poles, Towers and Fixtures	**81%**	50%	70%	40%	21%	35%	36%	50%
Conductors & Devices	**65%**	50%	70%	40%	21%	40%	36%	50%
Line Transformers	**69%**	50%	60%	0%	100%		27%	25%

These data are presented graphically in the figure that follows. The hatched bars show the average of the utilities surveyed other than FBC.



This figure demonstrates that FBC classifies a substantially higher percentage of these distribution assets as customer-related than do its peers. This can also been seen in the following table, which compares the FBC values to the average of other utilities surveyed shown in the hatched bars in the above graph.

	FBC	Average of other utilities surveyed
Poles, Towers and Fixtures	**81%**	43%
Conductors & Devices	**65%**	44%
Line Transformers	**69%**	44%

Time has not permitted exploration of the reasons underlying these widely differing practices with respect to customer cost allocation, nor of the two outliers in the Line Transformer data (100% for Hydro-Quebec, and 0% for Manitoba Hydro). However, the question is important, as these three categories account for 65.9% of all distribution plant.[57]

The strength of the intra-class equity argument — that low-use residential customers are subsidized because they do not cover their full share of the customer cost — depends on the degree of confidence we have in the COSA, and in particular in the minimum system study that determines which distribution assets should be classified as customer-related.

In response to a BCUC IR, EES acknowledged that some utilities are moving away from minimum system studies to more complex methods:

> EES has increasingly seen the use of more detailed studies that look at the actual use of the distribution system by various customer classes, rather than completing the classification and allocation steps required by a minimum system study. This approach requires more detailed data than required by a minimum system study and provides a greater level of complexity. Typically, the analysis is completed for a sample of the system rather than for the entire system.
>
> EES agrees that there can be differences of opinion as to whether the theory associated with the use of a minimum system is correct. In our experience, however, any shift away from minimum system is towards the aforementioned more complex methods rather than to a more simple approach, such as 100 percent demand. This shift is related to an attempt to provide more accurate allocations made possible with greater data availability arising from new technologies.[58]

[57] Calculated from figures in COSA, tab “Rate Base”, rows 67-71 and row 77.

[58] Exhibit B-21, BCUC 2.118.1.

Absent a thorough investigation of the classification of distribution costs and of the adequacy of the minimum system study that underlies it, uncertainty remains as to the extent to which the current basic charge reflects the actual cost of service.

That said, it must be recalled that "fair apportionment of costs among customers" is just one of the eight Bonbright Principles (#2), which must of course be balanced with the others.

In Decision and Order G-156-10, on FBC's 2009 RDA, the Commission explicitly determined that Bonbright Principle #3 (price signals that encourage efficient use) should trump Principle #2, specifically in the context of the basic charge:

> [T]he Commission Panel is concerned that the existing relatively high basic charge gives wrong pricing signals and believes that Bonbright Principle 3 regarding the price signals encouraging conservation should trump Principle 2 which seems to support a higher basic charge.[59] [underlining added]

It concluded:

> **The Commission Panel finds that increasing the Basic Charge would be unacceptable, especially in view of the requirement for providing appropriate pricing signals for conservation and energy efficiency.[60]**

In the author's view, the reasons that led to Commission to reject an increase to the Basic Charge in FBC's 2009 RDA remain relevant, and the reasons invoked by FBC in support of its proposed increase in the residential customer charge are not persuasive. This proposal runs counter to the principle of encouraging energy conservation and efficiency through the volumetric charge.

FBC has acknowledged that, given the small size and early stage of the NM program, there is no need for action at this time with respect to its impacts on other customers.[61] Should that situation change at some time in the future, it would be advisable to address the problem directly, rather

[59] FBC 2009 RDA, Decision and Order G-156-10, p. 57.

[60] Ibid., p. 56.

[61] Exhibit B-1, Application, page 34.

than through increasing the basic charge, which could have wide implications with respect to conservation incentives for all of FBC's residential customers.

4. THE PROPOSED OPTIONAL TOU RATE

4.1. Context

FBC has indicated interest in time of use (TOU) rates for many years. In its 2009 rate design application, FBC said it intended to put mandatory TOU rates in place as soon as its AMI system was in place.[62] FBC acknowledged the need to reduce energy needs, but favoured doing so through DSM and "time-based conservation rates".[63] At the time, FBC showed little enthusiasm for RIB rates, claiming they "would be expected to have only a minimal impact in reducing system demand while having a questionable effect on energy conservation."[64]

In the 2009 FBC RDA proceeding, FBC argued that mandatory TOU rates were a better alternative than RIB rates because:

> "a customer choosing to use less electricity during the more expensive peak periods will likely not use more electricity during the off-peak period to compensate".[65]

In FBC's 2009 RDA, the Commission was not persuaded by these arguments. It disagreed with the FortisBC position "that a customer choosing to use less electricity during the peak periods will not use more electricity during the off-peak period to compensate."[66] The Panel found that "while TOU rates may result in a reduction in peak demand, residential inclining block rates can provide price signals for reducing the overall energy consumption"[67].

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[62] FBC 2011 RIB Application, Decision and Order G-156-10, page 51

[63] Ibid.

[64] Ibid.

[65] Ibid., pages 50-51.

[66] Ibid., p. 56.

[67] Ibid., p. 57.

In the 2011 FBC RIB rate proceeding, FBC continued to maintain that mandatory TOU rates are superior to RIB rates. FBC said that if RIB rates were mandated then it intended to offer "a suite of time-based rates to complement its mandatory RIB rate, likely on a voluntary basis."[68] This suite of optional TOU rates would presumably include critical peak pricing and/or other demand response tools. However, to date, no other time-related measures have been proposed.

4.2. Optional TOU and the Free Rider Problem

FBC says the intention of the proposed optional TOU rates is to incent participating customers to shift consumption from higher cost to lower cost periods.[69] Mandatory TOU rates are known to contribute to reducing demand. However, FBC has not advanced any evidence that optional TOU rates will have a similar effect.

Freeridership is a significant challenge with optional TOU rates. Depending on their consumption patterns, certain customers will be able to reduce their bills simply by switching to the TOU rate, without making any behavioural changes. In these cases, their switching to the TOU rate will reduce FBC's revenues but not its costs, resulting in an cost additional burden for other customers.

Customers in this situation are likely to be able to identify themselves, as, if its proposed optional TOU rates are approved, FBC intends to implement an online tool for customers to determine the impact on their bill of switching to the optional TOU rate.[70]

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[68] Decision and Order G-3-12, p. 18.

[69] Exhibit B-11, BCOAPO 1.55.1.

[70] Exhibit B-8, BCUC 1.95.1; Exhibit B-24, BCSEA 2.18.3.

FBC estimates that, under current rates, 19% of residential customers (22,421 accounts[71]) would be better off under the TOU option without any change in behaviour. If these customers were all to adopt the optional TOU rate and make no changes in their consumption patterns, the result would be lost revenues of $9.4 million (an average of $34.86/customer/month), with no corresponding reduction in costs.[72]

Likely, not all of the potential free riders would opt for TOU. Some may not know about it. Others may fear that, if their consumption pattern should change, their bills could go up. On the other hand, some customers for whom TOU is not advantageous may opt for it anyway, either because they didn't fully analyze their consumption patterns, or because they believe they can change their consumption profile in order to benefit. In the end, however, for the proposed optional residential TOU rate to be successful in relation to its objective, it would have to cause a reduction in the utility's costs that is significantly larger than the revenue deficiency due to freeridership.

4.2.1. Implications of the flat rate proposal

Should the Commission approve FBC's proposal to phase out its RCR, the number of residential customers who would be financially better off on the optional TOU rate with no change in consumption pattern would decline. As shown in the table below, the percentage of residential customers who would see a bill decrease under the TOU rate with no change in behaviour would fall from 19% under current rates to 13% in Year 1 of the proposed RCR phase-out, to just 6% in Year 5:[73]

[71] Exhibit B-24, BCSEA 2.18.1.

[72] Exhibit B-24, BCSEA 2.18.2 and 2.18.5.

[73] Exhibit B-21, BCUC 2.137.5.1. It should be noted that the column "Estimated Number of Customers with Bill Increase" is of little significance, since these customers would have no financial reason to opt for the TOU rate or to stay on the TOU rate if they had already chosen it.

	Estimated Number of Customers with Bill Decrease	Estimated Number of Customers with Bill Increase	Estimated Percent of Customers with Bill Decrease	Estimated Percent Revenue Reduction[8]	Estimated Revenue Deficiency
Residential (vs current rates)	21,963	93,632	19%	5.07%	$9,379,657
Residential (vs Year 1 proposal)	14,757	100,838	13%	3.81%	$7,054,205
Residential (vs Year 5 proposal)	7,474	108,121	6%	0.39%	$729,433

The estimated revenue deficiency — $9.4 million under current rates — would fall to $7.1 million in Year 1 of an RCR phase-out, and to just $0.7 million in Year 5.

Would TOU participants drop out as the benefit fades? Would they decline to participate in the first place, realizing that any benefit would be transitory? Or would they instead increase their efforts to reduce peak usage, year after year, as the benefit diminishes? There is nothing in the file to respond to these questions.

4.2.2. Uncertainties

FBC has indicated that it in unable to estimate how many customers will opt for the TOU rate, even without regard to the possible change in the rate design.[74] It states that:

> FBC does not believe that customers will opt for the TOU rate simply on the basis of being financially better off. The complexities of the TOU rate and having to change behaviour to avoid on-peak pricing may be a deterrent to many customers, even if they would save on their utility bills.[75]

The point is apparently that many consumers who would be financially better off under the TOU still would not necessarily opt for it. It also seems highly unlikely that consumers who would clearly pay more under the TOU would choose that option.

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[74] Exhibit B-8, BCUC 1.94.1.

[75] Exhibit B-12, BCSEA 1.34.3.

These concerns suggest that participation in the optional TOU rate will be limited. What, then, will be the benefit, in terms of reduced cost of service? According to FBC:

> The key success factor for the proposed optional TOU rates is general rate mitigation resulting from lower overall utility costs. The Company realizes that some customers may also see lower annual bills as compared to the default rate. However, without any accompanying utility cost benefit (including power purchases), this only leads to a transfer of revenue responsibility between customers.[76]

Lower utility costs in this sense will only occur to the extent that FBC customers participate in the TOU program, and that they actually shift their consumption away from peak hours.

FBC has not presented estimates of the number of participants in the optional TOU rate, of the amount of load that would be displaced from peak to off-peak, of the lost revenue due to free-riders, or of the cost savings that would be expected to flow therefrom. It simply proposes to implement the optional rate on a service-territory-wide basis, and to judge the benefits based on reporting after three years.

A better approach would be to implement an optional TOU pilot program, perhaps confined to a specific geographical area, other otherwise constrained, in order to develop a knowledge base with respect to how customer behaviour would change under such a rate.

4.3. Optional residential TOU rates in other jurisdictions

Some other jurisdictions are implementing optional residential TOU rates. Notably, in California, all three large investor-owned utilities will offer a variety of complex TOU options to all residential customers as of January 1, 2019.

The California context is, however, very different from that of the FBC service territory. California is very large and diverse, with high rates, a vigorously growing solar power sector, and rapidly changing load profiles. Increasing solar penetration has already resulted in shifting

[76] Exhibit B-21, BCUC 2.136.5.

peak hours from midday to the early evening in many areas. In this context, free ridership in optional TOU rates may well be a small price to pay to "break the ice" on a ratemaking tool that could become very important in the future.

Based on the evidence on the record, there is no reason to believe that these factors are at play in the FBC service territory. Rather, a full-scale optional TOU program appears to create a real risk to revenues for no realistically achievable benefit.

FBC's inability to predict penetration or behavioural changes due to its proposed optional residential TOU rate is understandable. For this reason, proceeding with an optional residential TOU pilot project (including a control group), in a limited geographic region, might be a useful step forward, to allow more informed planning in the future.

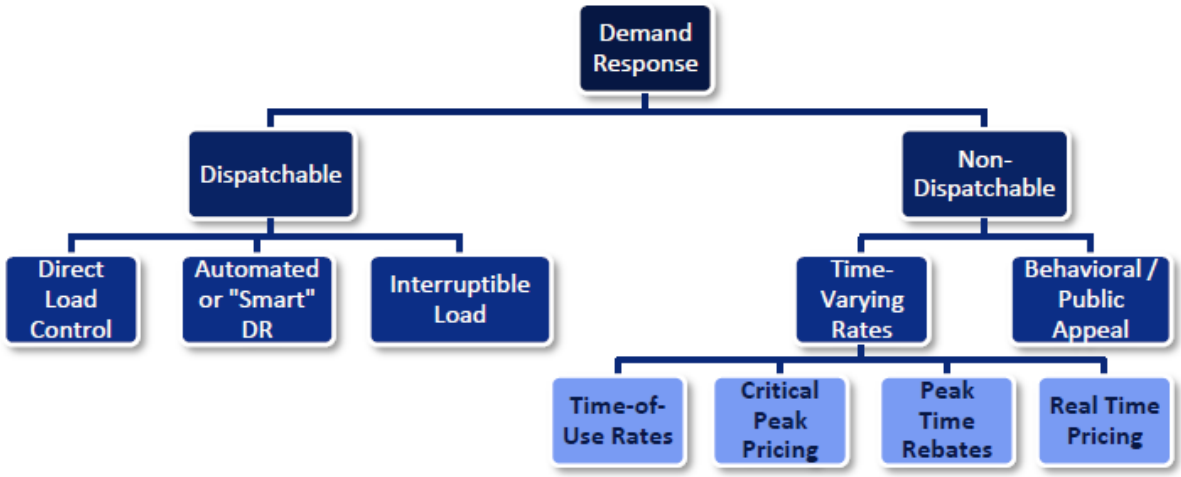
TOU, whether optional or mandatory, is just one of the policy tools collectively known as Demand Response (DR). Other important DR tools include critical peak pricing (CPP) and related measures, as well as dispatchable measures such as direct load control or "smart" DR.

In a recent proceeding in Quebec, Synapse Energy Economics presented a report that summarizes the current status of DR. While many of its recommendations are specific to Quebec, the overview it presents may be of interest to the Commission. A copy is provided as Appendix A.

A taxonomy of demand response resources, drawn from the Synapse study, is shown in the following figure.[78]

[78] Synapse Energy Economics, Best Practices in Utility Demand Response Programs, page 5.

Figure 1. Taxonomy of demand response resources



Very recently, HQ Distribution announced that it would implement both Critical Peak Pricing (CPP) and Critical Peak Credit (CPC) programs for its domestic and small business customers.

The CPP option involves a charge of 50¢/kWh for consumption during up to 100 critical hours per year, and reducing the Tier 1 and Tier 2 prices in the winter by 33% and 25%, respectively. HQD specifies that the rate is calibrated in order to diminish its interest to free riders ("*les opportunistes*"), who would see bill reductions without modifying their behaviour.[79]

The CPC option, on the other hand, is all carrot and no stick. It simply offers consumers a credit of 50¢/kWh for reducing their demand during the 100 critical hours below their personal baselines, based on past consumption patterns and weather normalized. HQD reserves the right to limit or terminate subscriptions.

[79] HQ Distribution, Stratégie tarifaire, HQD-13, doc. 2, docket R-4047-2018, July 27. 2018, page 27.

In developing this program, HQD mandated the firm Ad Hoc Recherche to consult its clientele using focus groups and interviews, with respect to three options: CPP, CPC and TOU rates.[80] Among domestic customers, it found greatest interest in the CPP and CPC options. The TOU option was not retained because interest in it was limited to households with electric vehicles and those with "smart home" technologies already installed.[81]

It should be noted that, like other demand response mechanisms, optional TOU is complementary to RCR, not a substitute for it. In California, the default is a tiered rate, as it is in Quebec.

4.4. Conclusion

Mandatory TOU rates, as envisioned by FBC back in 2009, would create a powerful incentive for residential customers to shift electricity consumption away from peak periods. However, there is no reason to expect that FBC's proposed optional residential TOU rate would induce a similar level of displacement or of cost savings that can be passed along to customers.

As noted above, a pilot program for an optional residential TOU rate would help to resolve some of the many uncertainties with respect to such a program.

There is no indication that FBC thoroughly explored a full range of Demand Response options before deciding on the optional TOU approach.

> Given that FBC already has TOU rate, and that these are the rates most familiar to customers (based on comments received during consultation), the Company did not entertain other rate options such as critical peak pricing.[82]

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[80] The Ad Hoc report has not yet been made public.

[81] HQ Distribution, Stratégie tarifaire, HQD-13, doc. 2, docket R-4047-2018, July 27. 2018, page 22.

[82] Exhibit B-8, BCUC 94.1.

If it did, perhaps it would conclude, as Hydro-Québec did, that Critical Peak Pricing and/or Critical Peak Credits would be a more effective way to reduce peak demand, with a lower risk of lost revenues due to free riders. It is recommended that FBC carry out a review of potential DR mechanisms, in order to determine the best path forward to reduce its peak demand.

Finally, it should be noted that, since the optional TOU rate would apparently have very different implications under the RCR than it would under a flat rate, there would be a benefit to reviewing these choices once the Commission's decision with respect to the flat rate proposal is known.

5. QUALIFICATIONS

Philip Raphals is cofounder and executive director of the Helios Centre, a non-profit energy research and consulting group based in Montreal. Over the last 25 years, he has written extensively on issues related to hydropower and competitive energy markets, and has appeared many times as an expert witness before energy and environmental regulators in several provinces.

Mr. Raphals has been formally recognized as an expert witness by energy regulators in the provinces of Quebec, Nova Scotia and Newfoundland and Labrador:

- In Quebec, he has provided expert testimony in 14 proceedings before the Régie de l'énergie du Québec. The Régie has recognized his expertise in fields including transmission ratemaking, security of supply, energy efficiency and avoided costs;

- The Nova Scotia Utilities and Review Board has qualified Mr. Raphals as expert in sustainable energy policy, least-cost energy planning and utility regulation (including transmission ratemaking). He provided expert testimony in two proceedings there concerning the Maritime Link, including critical analysis of long-term demand forecasts, resource options and financial analyses submitted by NSP Maritime Link Inc., a subsidiary of Emera, in support of its proposal to build an undersea transmission link between Newfoundland and Nova Scotia, and the accompanying long-term electricity supply contracts. In its decision, the Board quoted Mr. Raphals' report and relied in part on his analyses;

- The Newfoundland and Labrador Public Utilities Board has qualified Mr. Raphals as an expert in electric utility rate making and regulatory policy. He has provided expert testimony 2011 Muskrat Falls Review and in its hearings on the 2013 General Rate Application of Newfoundland and Labrador Hydro. He is currently acting as an expert witness in the 2017 GRA and related proceedings on behalf of the Labrador Interconnected Group.

In British Columbia, Mr. Raphals was coauthor of several expert reports submitted to the BCUC's Site C Inquiry on behalf of the University of British Columbia Program on Water Governance.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale Hydroelectric Project, where he coauthored with James Litchfield and Roy Hemmingway a study on the role of integrated resource planning in assessing the project's justification.

In 1995, Mr. Raphals was mandated by the Quebec Department of Natural Resources to prepare a study of integrated resource planning, as implemented by the BCUC. The study was part of the Public Debate on Energy that eventually led to the creation of the Régie de l'énergie.

In 1997, Mr. Raphals advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*.

Mr. Raphals chairs the Renewable Markets Advisory Panel for the Low Impact Hydropower Institute (LIHI) in the United States. He has been an invited speaker before the Senate Standing Committee on Energy, the Environment and Natural Resources, and member of an expert roundtable on electricity surpluses and economic development, convoked by the Quebec Commission on Energy Issues.

He has also been an invited speaker at numerous energy industry conferences, including the Canadian Association of Members of Public Utility Tribunals (CAMPUT), and at Yale University, Concordia University and McGill University.

In 2015, Mr. Raphals was a finalist for the R.J. Tremplin Prize, awarded by the Canadian Wind Energy Association for "scientific, technical, engineering or policy research and development work that has produced results that have served to significantly advance the wind energy industry in Canada."

APPENDIX A

SYNAPSE ENERGY ECONOMICS: BEST PRACTICES IN UTILITY DEMAND RESPONSE PROGRAMS

Best Practices in Utility Demand Response Programs

With Application to Hydro-Québec's 2017–2026 Supply Plan

Prepared for Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ)

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EXECUTIVE SUMMARY

Demand response (DR) has long been used by electric utilities to provide capacity, energy, or reliability to the grid. To determine the need and potential for demand response, every jurisdiction must assess its own unique characteristics for power supply and demand profile. In Québec, the primary features include the following:

- The power supply portfolio is almost invariant in cost and availability, except during a few peak periods.
- Those peak periods are almost exclusively driven by the coldest winter weather.
- Electric rates are quite low, compared with other provinces or U.S. states and with the cost of fossil fuels for heating. This results in extensive use of electric space and water heating.
- HydroQuébec Distribution (HQD or the Distributor) has deployed advanced metering infrastructure (AMI) throughout its service territory.
- Québec is taking serious and concerted action to reduce greenhouse gas emissions through the electrification of additional end-uses, particularly electric vehicles.

These features combine to produce an environment in which demand response can play a more central role in the HQD's supply planning than it would play in other jurisdictions. However, HQD's current DR programs are somewhat smaller (as a fraction of winter peak) than those of other large, winter-peaking utilities.

While demand response in every jurisdiction has its own unique characteristics, the broad strokes of best practices for utility DR programs remain relatively consistent:

- Programs should be designed for their context and with consideration for their objectives.
- Program administrators should know the DR potential and plan carefully to meet it.
- Programs should take advantage of technology, such as AMI and smart appliances.
- Programs should address a range of measures and sectors to identify and capture least-cost resources.
- Programs should engage with customers on terms that make sense to them, and capture economies of scale with other customer engagement strategies.
- Programs should be cognizant of costs and benefits, and update both as circumstances change.

Applying the lessons learned from examination of HQD programs in light of these best practices, we recommend the following actions:

- HQD should re-orient how it plans for DR resources to an approach based on achieving the cost-effective potential, rather than projecting only continuation of existing programs. Stochastic supply planning, which accounts for variations in supply, may also be useful. This orientation includes conducting DR potential studies on a regular basis.

- HQD's approach to calculating avoided costs should be revised (and updated regularly) to take into account the differences in avoided costs between HQD's peak and other hours and to allow customized avoided costs to be calculated for different kinds of DR interventions.

- To identify and harness the full cost-effective residential flexible capacity resource, HQD should build on its 2008–2010 time-of-use and critical peak price rate pilot by testing new peak time rebate or critical peak price programs. If they prove promising and cost-effective, HQD should then introduce them as general opt-in or opt-out options to all customers. We hypothesize that an opt-out peak time rebate program appears most likely to maximize cost-effective demand savings and meet with customer acceptance, but market testing is necessary.

- As HQD develops new DR programs and moves them from pilot to implementation, it is important to move with all due haste to launch programs and capture the cost-effective potential. HQD's water heater program is particularly promising and the Distributor should continue to advocate for it.

- HQD should incorporate the use of standards (such as the Universal Smart Network Access Port or OpenADR) in its program design to maximize its ability to adopt technologies developed elsewhere.

- HQD should quantify the impacts of its occasional appeals for peak reduction, and use best practices for evaluation, measurement, and verification of DR programs.

- HQD should integrate demand response into its energy efficiency offerings where cost-effective opportunities exist.

- We encourage HQD to continue to diversify its DR program offerings or make them more flexible, especially for commercial and industrial customers. This will encourage greater participation on terms that make sense for both participant and Distributor. In particular, we recommend that DR program designs encompass aggregators.

1. INTRODUCTION

On November 1, 2016, HydroQuébec Distribution (HQD or the Distributor) filed its 2017–2026 Supply Plan. This Supply Plan identifies a need for additional winter peak capacity beginning in the winter of 2017–2018, driven primarily by continued growth in the Distributor's winter peak. The Supply Plan anticipates meeting this near-term peak capacity need through market purchases. By the end of the Supply Plan period, however, the capacity shortfall is beyond the reach of the short-term market. The Supply Plan also discusses the demand response (DR) and other demand-side resources that HQD expects to be able to deploy in each year to help meet this demand. These resources reflect a maturing set of programs that retain significant growth potential, although the Supply Plan does not quantify some aspects of that potential.

The purpose of this report is to identify best practices regarding the use of demand response as a utility resource, drawing on examples from around the United States and Canada. The report also puts those best practices into the Québec context to develop a set of recommendations regarding how HQD could improve both its DR programs and how those programs are accounted for in its Supply Plans.

In Québec, the primary need is for winter capacity. The Distributor's energy costs do not vary substantially aside from near winter peak, and optimizing use of patrimonial energy and short-term markets can reduce cost of service. In addition, there may be locational needs for DR capacity where the Distributor has growing loads. The discussion of best practices contained here includes measures and tools designed to address both summer and winter peaks: even programs aimed at summer peaks have lessons to teach winter programs.

2. DEMAND RESPONSE AS A RESOURCE

2.1. Why Demand Response?

Electric utilities often use demand response to provide capacity, energy, or reliability to the grid. By reducing demand during a small number of peak demand hours per year, demand response enables utilities to avoid costly capital investments in generation capacity that would be infrequently used. Demand response may also be used to provide capacity in constrained local areas of the grid, thereby avoiding transmission or distribution upgrades. As an energy resource, demand response can be deployed when energy costs are high, for example when fuel prices spike suddenly. Demand response also may operate as a reliability resource that is deployed during emergencies. To give an example, it can help avoid brownouts, blackouts, or more expensive emergency generation during a power plant forced outage.

In recent years, demand response has begun to be used to enhance grid flexibility through the provision of ancillary services, such as frequency response or load following. In this capacity, demand response

may quickly decrease or increase load, depending on the needs of the utility or system operator. Such services facilitate the integration of variable renewable resources by absorbing excess energy during periods of oversupply and maintaining the minute-to-minute balance between electricity supply and demand. DR resources that provide these types of services often are automated and utilize some form of energy storage such as batteries, water heaters, or other forms of thermal storage.

Demand response's load modifying capability enables more efficient use of current electricity generation resources, while yielding economic, reliability, and environmental benefits. Yet demand response is not a homogenous resource; it is provided by a highly diverse set of actors in numerous different ways, and with varying capabilities. This diversity precludes any simple characterization of DR types and also contributes to the flexibility of demand response to meet multiple system needs. The following section provides an overview of the various forms of demand response.

2.2. Types of Demand Response

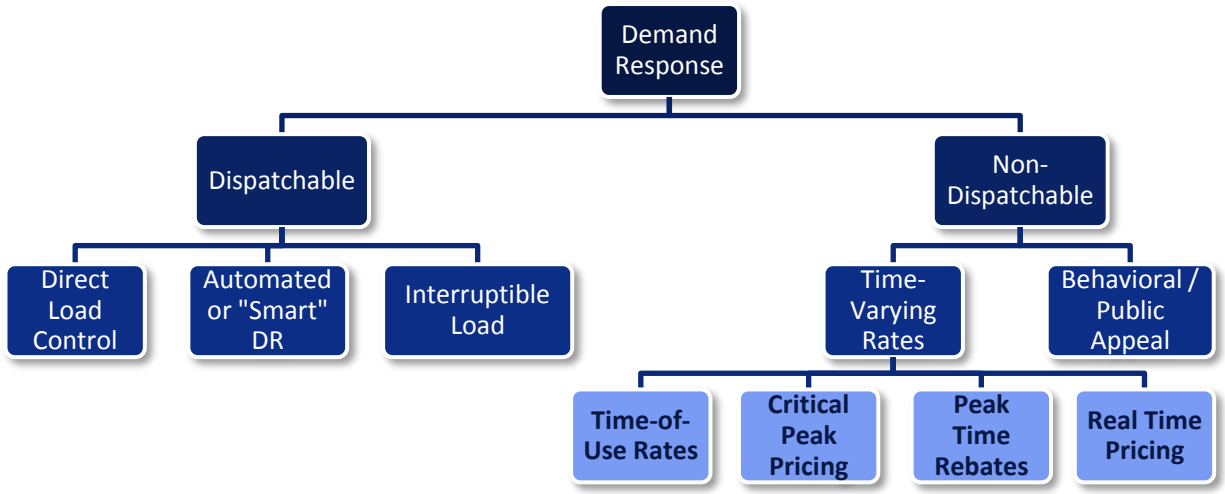
All categories of customers (industrial, commercial, and residential) employing many different technologies or strategies can provide demand response. However, the deployment of such resources generally varies by customer type.

DR resources are typically deployed in two distinct ways: either the utility (or other system operator) directly dispatches the resources, or customers voluntarily elect to adjust their consumption in response to price signals (referred to as "non-dispatchable" DR). Customers with dispatchable resources typically enter into contracts to receive payments for demand reductions, and they may face penalties for non-performance. Dispatchable programs are common in the commercial and industrial sectors (including agriculture).

In contrast, non-dispatchable resources generally participate in price-based DR programs such as real-time pricing, critical peak pricing, peak time rebates, and time-of-use tariffs. These price-based programs provide users with ongoing price signals to encourage lower energy consumption during periods of high electricity prices. Non-dispatchable demand response programs have been used for many years for large commercial and industrial users, and they are becoming more common for residential and small commercial users. The adoption of advanced metering technologies has spurred the expansion of price-based programs to residential and small commercial.

Figure 1, below, depicts common types of demand-side resources.

Figure 1. Taxonomy of demand response resources



3. THE QUÉBEC CONTEXT FOR DEMAND RESPONSE

Every jurisdiction has its own unique characteristics for power supply and demand profile, which shape both the need and potential for demand response. In Québec, the primary features include:

- The power supply portfolio is almost invariant in cost and availability, except during a few peak periods.
- Those peak periods are almost exclusively driven by the coldest winter weather.
- Electric rates are quite low, compared with other provinces or U.S. states and with the cost of fossil fuels for heating, resulting in extensive use of electric space and water heating.
- HQD has deployed advanced metering infrastructure (AMI) throughout its service territory.
- Québec is taking serious and concerted action to reduce greenhouse gas emissions through the electrification of additional end-uses, particularly electric vehicles (EVs).

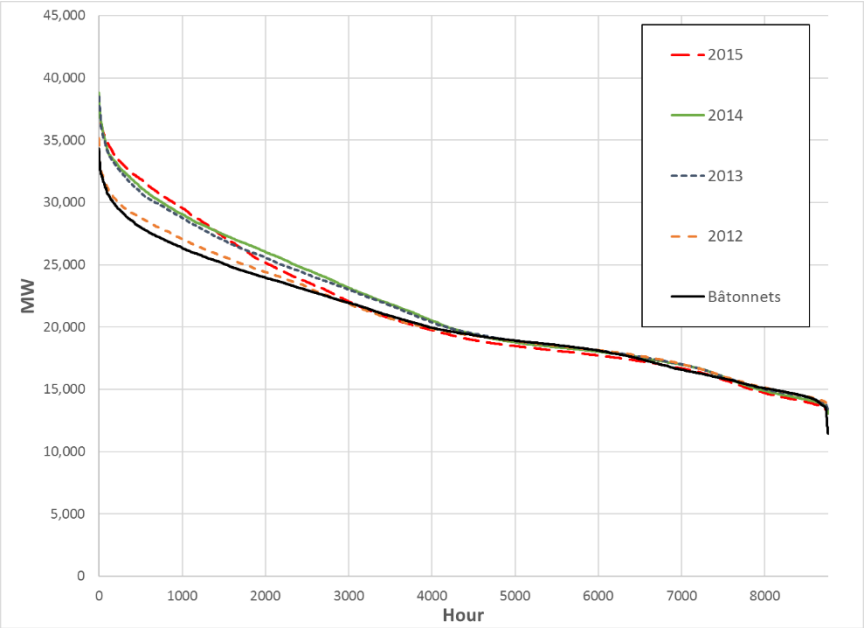
These features combine to produce an environment in which demand response can play a more central role in the HQD's supply planning than it would play in other jurisdictions.

Let us turn first to the interaction of HQD's power supply portfolio and its load shape. HQD has a highly flexible and available patrimonial supply of energy from Québec's hydroelectric resources that is priced on a constant per-kWh basis. In addition, the Distributor has a growing contribution of wind resources and some other long-term contracts. These resources meet the vast majority of HQD's customers' needs

for energy, supplemented by short-term bilateral and market purchases. Since these other resources can be considerably more expensive than the Distributor's legacy supply, efforts to reduce these costs can have a substantial impact on the overall cost of service. Because these peaks are highly correlated with the weather, they are also quite predictable. Due to these characteristics, demand response and other resources that are dispatchable with a day's notice are a good fit. Given the unique characteristics of the patrimonial supply, where "bâtonnets" are assigned to each hour of load, it may also be beneficial to have some resources that are dispatchable with shorter lead times. This would include "smart DR" enabled by two-way communication. Smart DR would also enable the targeting of DR activation to circuits experiencing specific constraints due to load growth or changes (including increasing air conditioning in summer).

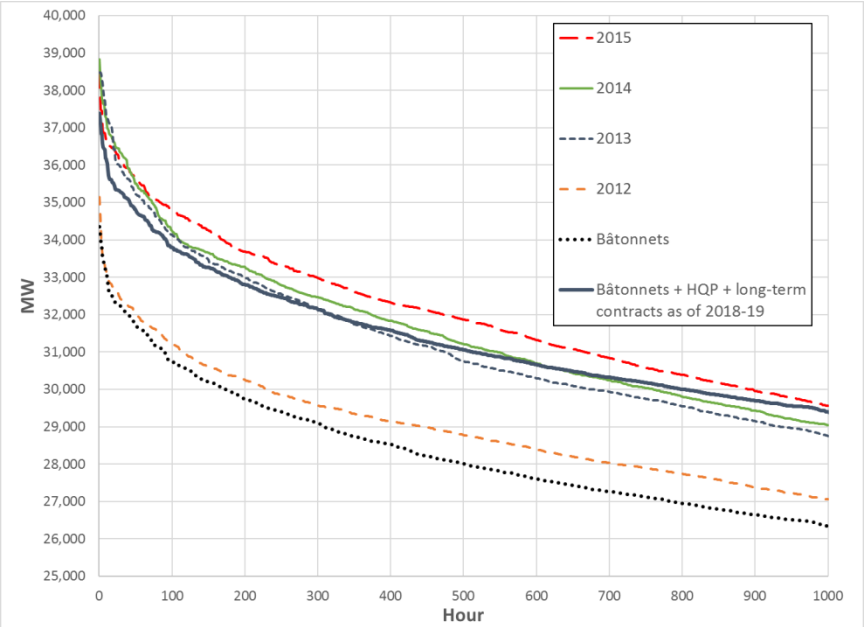
Figure 2 shows HQD's load duration curve for the years 2012–2015, along with the 8,760 "bâtonnets." HQD's power supply portfolio challenge is how to most cost-effectively meet the annual load by building on top of the patrimonial load shape. There is noticeable variation by year, although general trends are consistent with HQD's anticipated continued slow increase in peak and sales. The sharpest winter peaks for the last three years available are tightly clustered.

Figure 2: HQD load duration curves for 2012-2015, with the "bâtonnets"



Source: R-3986-2016, B-0044 through B-0047.

Figure 3: Top 1,000 hours of the HQD load duration curves for 2012-2015, with the "bâtonnets" and "bâtonnets" plus long-term contracts



Source: R-3986-2016, B-0006, Table 7 and B-0044 through B-0047.

Figure 3 shows the top 1,000 hours of load for the years 2012–2015, along with the top 1,000 "bâtonnets." In addition, the figure shows (solid black line) the "bâtonnets" plus 3,051 MW. These 3,051 MW correspond to the long-term contracts with HQP (600 MW), the A/O 2015-01 tender (500 MW) and the wind, biomass, and small hydro contracts (1,951 MW) as of 2018–19. Demand response or efficiency as it was implemented in each past year is already reflected in the load curve. Going forward, incremental demand management or short-term supplies are required to bridge the gap between the patrimonial and long-term supplies and actual load (which are expected to continue to grow, and will be subject to the fluctuations of annual weather and economic activity). Programs for demand response and other load management measures benefit customers to the extent that they enable HQD to more cost-effectively utilize the patrimonial supply and avoid peak market and infrastructure costs.

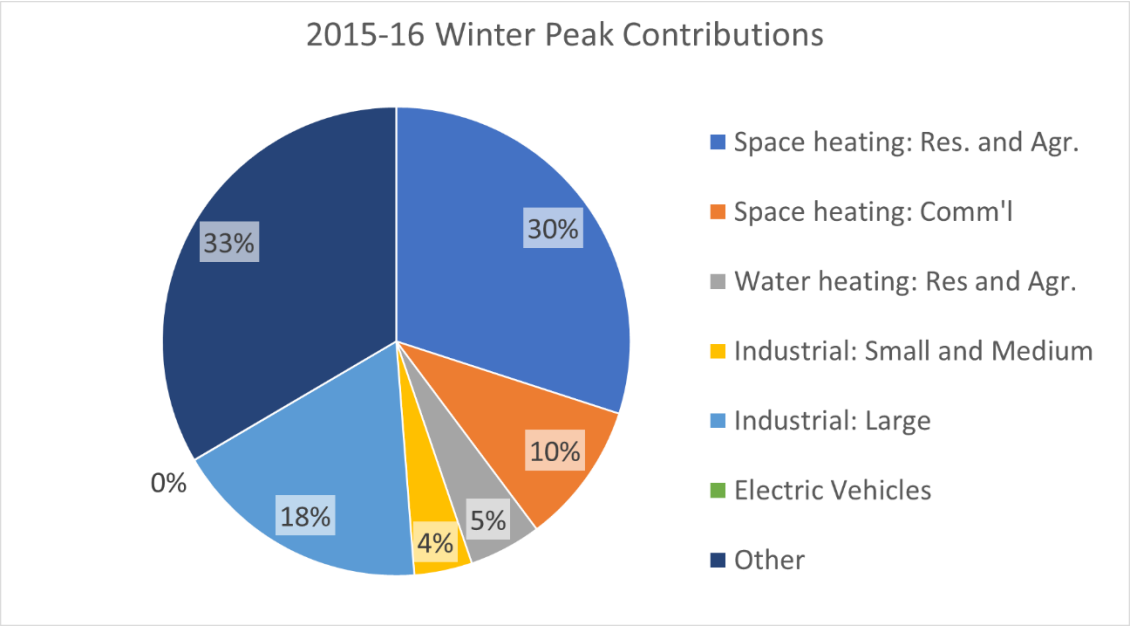
Another defining characteristic of HQD's legacy power supply is its low cost. This low cost has encouraged many building owners to choose electric space and water heating. The Distributor's winter peak occurs at the coldest times of winter because of the widespread use of these technologies. That also means they provide the primary avenues for addressing the winter peak through efficiency and demand response. Québec's unique development and use of three-element water heaters reflects these particular circumstances.

Provincial building patterns have combined with these rates to favor the use of electric space heating, particularly electric baseboard heating. Where Québec has adopted technologies at scale that are not as dominant elsewhere, as with baseboard electric heat, Québec suffers from the lack of focus and attention that technology firms or manufacturers might otherwise direct toward controlling those

technologies. Advanced communicating thermostats, such as the Nest or Ecobee, are not generally compatible with baseboard heating. Moreover, if they were compatible, they would be less cost-effective because the room-by-room control of baseboard heat would necessitate a separate expensive thermostat for each room.

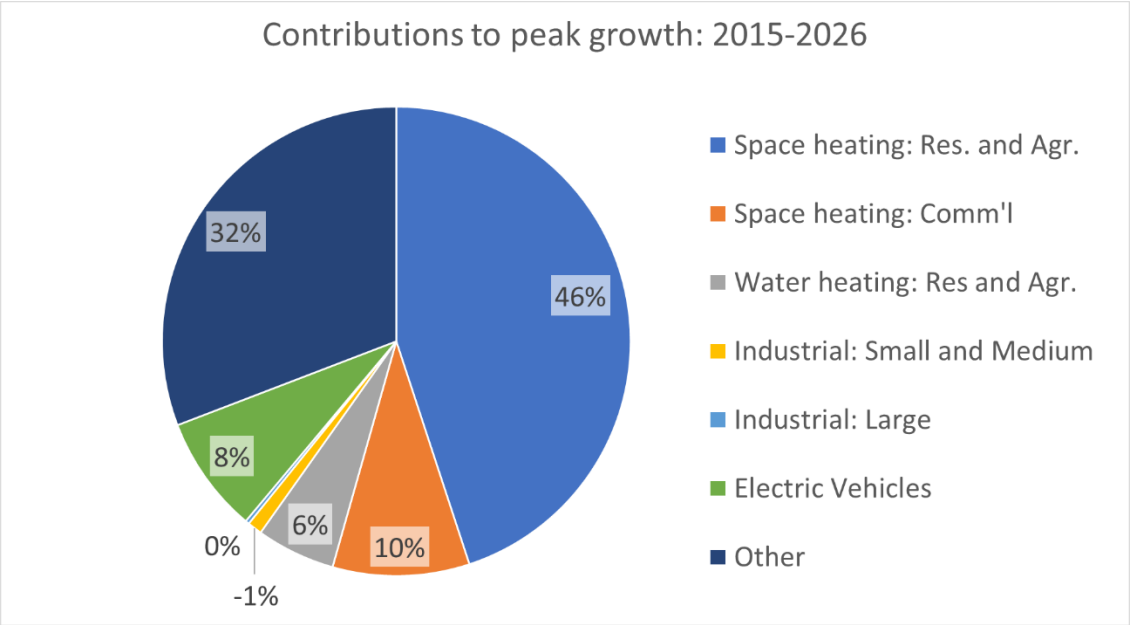
The load characteristics described here lead to a winter peak dominated by space heating, followed by miscellaneous other uses and industrial processes, then water heating; see Figure 4 for the contributions to peak from each end use or sector in 2015–2016. The sources of growth in peak through 2026 are somewhat different: space heating dominates even more, while EVs emerge as a significant driver. Figure 5 shows the contributions of each end use to the growth in winter peak.

Figure 4: Winter peak contributions of identified end uses or sectors, 2015-2016



Sources: R-3986-2016 HQD-1, document 2.2 and Réponses à la demande de renseignements no 1 de la FCEI, Response 3.6.

Figure 5: Contributions to winter peak growth between 2015 and 2026 from identified end uses and sectors



Sources: R-3986-2016 HQD-1, document 2.2 and Réponses à la demande de renseignements no 1 de la FCEI, Response 3.6.

While a given sector or end use may be responsible for some portion of peak, or some portion of the growth in peak, that does not necessarily indicate that that sector or end use is the least cost or most available resource for demand response. For example, HQD's current interruptible load program for industrial customers is projected to grow, while the sector's contribution to peak falls. While HQD's DR potential study from 2012 is out of date,[1] it indicates that the greatest DR potential can be found in commercial heating and ventilation systems. DR potential in residential heating systems is somewhat smaller, although heating is the largest source of potential for both residential and commercial sectors. Even though commercial heating is only one-third of the residential contribution at peak, its greater controllability indicates a higher potential. Other large potential exists in water heaters and behavioral changes (especially the use of clothes dryers).

HQD has deployed AMI throughout its service territory, with Zigbee communications technology installed. This deployment could enable two key aspects of residential and small commercial demand response or other peak-directed savings. First, it would allow the development of rate structures that differentiate between consumption at peak days and times from other consumption. Second, it would allow wireless communication within customers' premises to send control signals to appliances, triggering DR behavior. HQD has not yet proposed to use either of these capabilities.

[1] État d'avancement 2012 du Plan 2011-2020, *Potentiel technico-économique de gestion de la demande en puissance*. The study examined the potential only through the winter of 2016–17.

Québec has established ambitious goals for the deployment of plug-in EVs as a key component of its policy to mitigate global climate change and reduce dependence on fuels not produced in the province. These goals include the use of 100,000 EVs by 2020 and 300,000 EVs by 2026.[2] HQD has incorporated energy use and peak impacts of these new loads in its energy and demand forecasts, including an estimate of 0.6 kW of peak impact for each EV. This results in a contribution of 189 MW by 2025, or 8.5 percent of the increase in winter peak forecast over the 10-year Supply Plan.[3] EVs are a much more flexible load than other appliances or services, and as such can play a role akin to electric storage on the grid. HQD has not yet launched or piloted any DR programs aimed at mitigating these new loads' impact on winter peak, and the Supply Plan does not discuss demand response or controllability of EV loads.

HQD's Supply Plan identifies two classes of DR resource: "interruptible electricity" (primarily industrial customers) and "new demand response programs" (which includes residential controlled or interruptible loads; "GDP Affaires" or commercial/industrial building interruptible loads; and controlling or interrupting loads in Hydro-Québec's own facilities). The existing industrial program is projected to achieve 850 MW of DR capability in the winter of 2016–17, rising to 1000 MW by the winter of 2018–19. It remains flat for the rest of the study period. Historical participation in this program has varied, but in the last two winters it has exceeded the amount planned for in the Supply Plan; see Table 1.

Table 1: Participating MW of winter peak capacity in "Grande puissance" interruptible rate programs

Winter	2011-12	2012-13	2013-14	2014-15	2015-16
Interruptible capacity (MW)	611 - 702	964 - 974	698	1032	1113.6

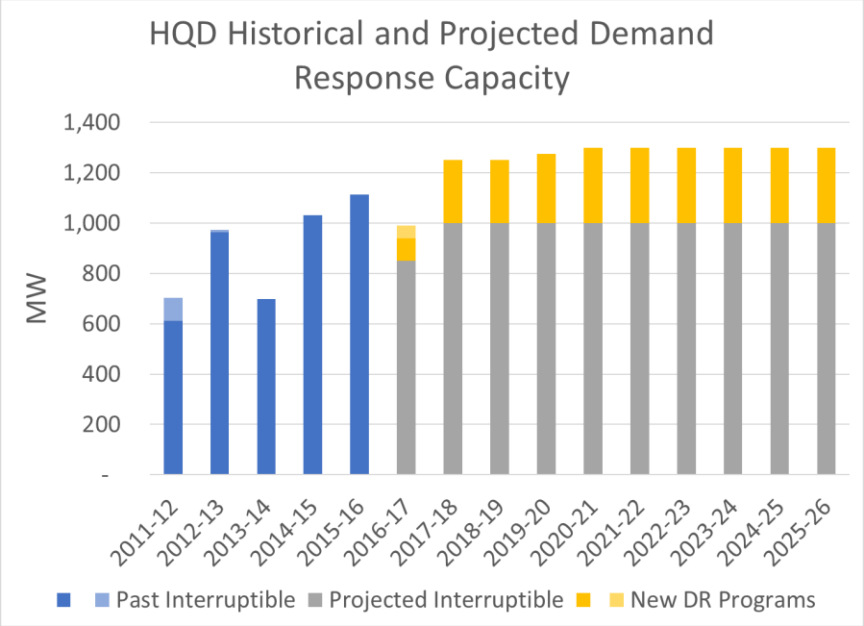
Source: HQD-3, document 2.1 from each of the 2012 to 2015 Annual Reports.

New DR programs are projected to start at 90 MW in 2016–17 (although Response 1.3, HQD-3, document 6.2 indicates achievement of 140 MW this winter) rising to 300 MW in 2020–21 and then remaining flat. As a fraction of expected winter peak, these programs imply DR capacity equal to approximately 2.5 percent of the winter peak (940/37,630), rising to 3.4 percent (1,300/38,678) by 2021, then falling to 3.3 percent by 2026 as projected DR capacity stagnates and load continues to rise. Figure 6 shows HQD's historical and projected DR capacity from 2011 to 2026.

[2] "The 2030 Energy Policy: Energy in Québec A Source of Growth," page 41, https://politiqueenergetique.gouv.qc.ca/wp-content/uploads/Energy-Policy-2030.pdf

[3] R-3986-2016 HQD-1, document 2.2 and Réponses à la demande de renseignements no 1 de la FCEI, Response 3.6

Figure 6: Historical and projected demand response



Source: Supply Plan (HQD-1, Document 1) page 19; HQD-3, document 2.1 from each of the 2012 to 2015 Annual Reports.

HQD has piloted direct load control of water heaters. However, this program is on hold as HQD works with health authorities to increase their comfort with the program, due to a concern about infection risk from legionella bacteria. It is also piloting load control for central and baseboard heating systems, as well as dual-fuel heating systems. HQD makes public appeals for conservation on the peak days. But because it has not quantified the impact of these appeals, and the Distributor cannot include them in its winter peak capacity plan.

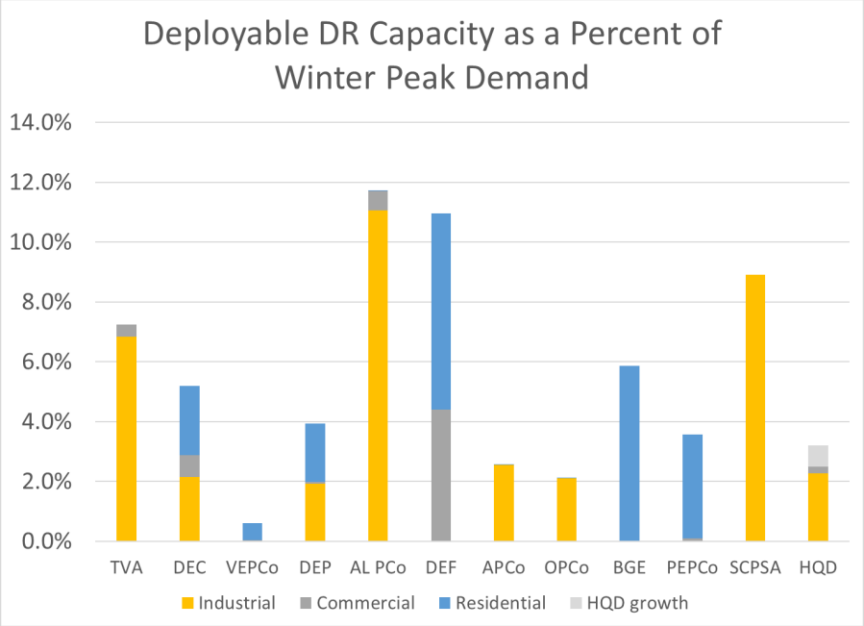
HQD also conducts a kind of critical peak price-based demand response in the form of Rate DT for customers with dual-fuel heating systems. This rate is only available to customers with a second, non-electric heating system (or thermal storage), preferably with automatic switch-over. The rate is triggered based on temperature rather than grid conditions or utility event call, although temperature and grid conditions are closely related. It provides a significant price signal: below -12 or -15 degrees Celsius, the customer sees a rate that is nearly six times as high as the rest of the time; and their non-cold-weather rate is 20 percent to almost 50 percent lower (depending on monthly use) than non-DT customers experience. Despite the favorable economics offered with this rate, participation has been falling as customers chose simpler single-fuel heating options.

3.1. Comparison with Demand Response Elsewhere

While DR capacity depends on the particular end uses and load characteristics of a utility, this section compares HQD's planned DR capacity, as a fraction of peak load, with those of other utilities. Table 2 identifies the 11 largest winter-peaking U.S. utilities, and provides data from the U.S. Energy Information

Administration regarding their deployable DR potential and customer participation in 2015.[4] The demand response identified here does not include changes in load resulting from rate programs such as peak time rebates. The variation among utility approaches to demand response is apparent from this table: some utilities target almost exclusively commercial and industrial customers; others rely on large residential programs. Regardless, their weighted average of deployable DR potential as a fraction of winter peak is 5.7 percent. On this metric, HQD would rank tenth of 12 if inserted onto this list, with plans over the next decade to climb to ninth. Figure 7 shows the DR capacity as a fraction of winter peak for the 11 U.S. utilities along with HQD, broken out by sector. The lighter area on the HQD bar shows the Distributor's proposed program growth.

Figure 7: Deployable DR capacity as a fraction of winter peak for 11 large U.S. utilities and HQD



Source: U.S. Energy Information Administration Form 861; Supply Plan (HQD-1, Document 1), page 19.

In terms of MW of capacity, HQD would be third on this list for industrial demand response (if one assigns the interruptible electricity program to that sector entirely); as a fraction of load it would be clustered with the second tier of programs. HQD's new 140 MW commercial program would be the second largest on this list by capacity, and fifth largest by fraction of peak load. HQD does not yet address the residential sector, where some utilities find substantial DR resources.

[4] This table is limited to winter-peaking utilities to find closer analogs to HQD, rather than focusing on air-conditioning-dominant summer peaking systems. Regardless, some of these are southern utilities that may have winter cooling loads, or focus their DR programs on summer peaks. In fact, some may be winter peaking *because* summer-focused demand response and energy efficiency have reduced their summer peaks.

The weighted average cost of demand response among these 11 programs is $47/kW. After accounting for currency conversion, this remains well below the current understanding of HQD's long-term avoided costs for capacity on winter peak ($108/kW). Table 2 indicates that residential DR programs are more expensive than commercial or industrial programs as a general tendency, although the residential-heavy programs here have costs that are still close to HQD's long-term avoided capacity cost (CDN$108/kW-year). Note that DR programs can also save other costs: to the extent that they move load from times of high energy prices to lower-priced times or stimulate conservation (overall reductions in energy use), those benefits are not captured in a pure $/kW metric focused on capacity.

The wholesale energy and capacity markets in the United States and Canada also provide an opportunity to gauge the scale of DR programs. Where demand response can participate directly in wholesale markets, those markets, rather than utility programs, tend to be the primary drivers of DR capacity. The Independent System Operator of New England (ISO-NE), for example, runs a capacity market in which demand response competes directly with supply options. DR resources in that market must be able to provide response at any point in the year (meeting either winter or summer capacity needs), which limits the ability of heating or cooling systems to participate. Regardless, the markets have produced an average of 2.7 percent of winter peak achievable with demand response during the winters of 2015–16 through 2019–2021.

In Ontario, demand response totaling 455 MW in the summer of 2017 and 478 MW in the winter of 2017–18 cleared the most recent Independent Electricity System Operator (IESO) auction. This wholesale market demand response is in addition to about 1 GW of industrial demand response. Together these DR resources are equivalent to about 6 percent of the projected summer peak and nearly 7 percent of the projected winter peak.[5]

[5] Derived from the 2016 IESO Ontario Planning Outlook, http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Table 2: 2015 demand response portfolios of the eleven largest U.S. winter-peaking utilities

Utility	2015 Peak (MW)		Deployable DR (MW)	Deployable DR % of winter peak	Program costs (US$/kW)	Residential		Commercial		Industrial	
	Winter	Summer				MW	% particip.	MW	# particip.	MW	# particip.
Tennessee Valley Authority	32,751	29,043	2,370	7.2%	$33	-	-	128	951	2,242	541
Duke Energy Carolinas	18,490	17,353	961	5.2%	$35	431	9%	133	172	397	307
Virginia Electric & Power Co	18,434	16,502	110	0.6%	$95	103	6%	7	6	-	-
Duke Energy Progress	14,814	12,280	582	3.9%	$34	289	11%	7	16	286	90
Alabama Power Co	12,398	11,600	1,452	11.7%	$17	0	0%	81	63	1,371	124
Duke Energy Florida	9,475	9,219	1,039	11.0%	$78	623	27%	416	772	-	-
Appalachian Power Co	8,690	5,729	223	2.6%	-	2	0%	-	-	221	10
Ohio Power Co	6,784	3,423	144	2.1%	-	1	0%	-	-	143	2
Baltimore Gas & Electric	6,712	6,507	394	5.9%	$94	394	36%	-	-	-	-
Potomac Electric Power (Pepco)	6,042	5,485	216	3.6%	$117	210	28%	6	1,756	-	-
South Carolina Public Service Authority	5,869	4,979	523	8.9%	$101	-	0%	-	-	523	20

Source: U.S. Energy Information Administration Form 861.

4. Best Practices in Utility Demand Response Programs

Despite variations across jurisdictions, some basic principles and best practices for utility DR programs remain relatively consistent:

Distributors and system operators implementing demand response programs should:	Design programs appropriate for the jurisdiction's context and objectives
	Quantify the DR potential and develop a plan to meet it
	Take advantage of AMI, smart appliances, and other technologies
	Address a range of measures and sectors to identify and capture least-cost resources
	Effectively engage with customers, and capture economies of scale with other customer engagement initiatives
	Continually assess costs and benefits and update both as circumstances change

4.1. Design for Context

Utility DR programs reflect the needs of the electric system in which they operate. Where the drivers of cost are summer peaks, DR programs focus on end uses driven by hot summer weather, such as air conditioning. Where electric rates are low enough that electric water heating is common, DR programs can be designed to harness the controllability of that resource. Situations in which the grid is stressed by the integration of variable generation favor “smart” DR programs that can dynamically increase or decrease load (including in specific locations).

Weather-dependent peaks, such as in Québec, put a premium on the interaction of weather and load forecasting to identify when the grid will be stressed. Customers with DR resources expect to be called to perform a limited number of hours each winter; calling events when the system ends up not needing them wastes customer engagement and willingness to participate.

Vermont

One example of an emerging utility practice for joint load and weather forecasting is the Vermont Weather Analytics Center (VTWAC), developed by IBM Research and the Vermont Electric Power

Company.[6] The center combines hyper-local weather forecasting from IBM's Deep Thunder platform with machine learning on the interaction of weather and utility load (informed by AMI data from 90+ percent of Vermont electric customers) to predict hourly load up to 72 hours in advance. Weather is also the driver of solar and wind production, so the resulting power flows can take that into account. VTWAC claims 97.6 percent accuracy for statewide energy demand forecasting, including 95.1 percent solar forecast accuracy and 92.8 percent wind forecast accuracy, both 24 hours ahead. Vermont utilities use the load forecast to determine when to deploy their DR resources.

Another critical part of context for program design is the cost drivers that are being avoided by demand response. In the Vermont context, for example, utilities face a monthly peak cost associated with regional transmission costs as well as a larger annual summer peak associated with capacity. Regional energy prices vary in a small enough range over the course of the day that shifting load a few hours over the day does not produce enough energy market savings to make a program aimed at that resource cost-effective. As variable distributed generation resources continue to increase, circuit-specific DR resources may become cost-effective. As we will see, other jurisdictions have different cost drivers and opportunities. For instance, energy arbitrage alone can be cost-effective in some places.

Pennsylvania

Pennsylvania's Act 129 of 2008 required electric utilities in that state to acquire energy efficiency equivalent to 3 percent of sales by 2013, along with reducing peak demand 4.5 percent in the top 100 hours of load. Beginning in 2012, the Pennsylvania Public Utilities Commission (PPUC) required that utilities begin to implement DR programs as part of their efforts to hit the 4.5 percent target. Unusually, the PPUC specified the parameters for when DR events would be called in some detail, likely driven by the requirement to target 100 hours. When the PPUC set about to revisit those requirements to set new goals for the period after 2013, it took a careful path through cost-effectiveness review that provides an example of responsive regulation and the importance of characterizing the programs' objective in context.

The PPUC commissioned a potential study[7] which showed that the programs initiated after the 2012 requirement were not cost-effective. The study's authors suggested that this was in part because the programs were being pulled into low-reward implementation by the requirement to target the 100 highest load hours. They found that in most summers fewer than 30 hours were cost-effective for demand response. They suggested that a program that targeted a more limited number of hours could be cost-effective. The PPUC took stakeholder input (from utilities, generators, and DR providers) and adopted a revised program that, while still prescribing the calling of DR events, better reflects the market reality: no more than six, four-hour events each summer, called when PJM load is expected to exceed 96 percent of the summer peak demand forecast.

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[6] More information is available at http://www.velco.com/our-work/innovation/vtwac2

[7] Available at http://www.puc.pa.gov/pcdocs/1256728.docx

This example shows both the downside of a regulatory scheme for DR program design that does not reflect the actual cost context, and the benefits of a responsive framework that changes that design in response to market conditions.

4.2. Potential and Planning

A utility must plan carefully, with a long planning horizon, to be able to harness the most cost-effective resources for its customers. While a new supply contract may be signed just before power is required (if excess is available from a nearby generator), demand-side resources require time to acquire due to the time to ramp up programs and engage customers in operational or hardware changes in their end uses. If a utility fails to plan appropriately, it may be forced to choose a more expensive supply option, rather than the less expensive demand-side resource. Circumstances also change: supply prices may rise or fall, new technologies may become available, or public policy may change. This results in the need to revisit plans on a regular basis with the most up-to-date information.

Planning also provides a critical juncture in a utility's operations to engage with stakeholders and regulators. Decisions informed by integrated planning exercises can be among the most expensive and consequential that a utility makes, and at the same time planning is among the more approachable aspects of utility operations or regulation.

Planning for demand-side resources, whether they are passive energy efficiency measures or active demand response, generally begins with an assessment of the resource potential. After the potential, and the cost to acquire that potential, is known, the demand-side resource can be integrated and compared with other supply-side options on a level playing field. Resource assessment can be undertaken from a variety of perspectives, such as the utility ratepayer perspective or a societal perspective. The assessment should reflect the public policy priorities and perspective set by elected and appointed leaders, and it may include externalities (such as greenhouse gas emissions) or local economic impacts. Such comparisons need to encompass a sufficiently lengthy time horizon: while a supply resource may be contracted for a limited period, a demand-side resource typically delivers over the life of the measure. In addition, programs that shape markets cannot be casually turned on or off as prices change. For example, a facility may acquire an energy management system justified in part on the revenues from demand response; program credibility depends on either a long-term stream of predictable revenues or economics that reflect the risk of the investment and offer a short payback. Long-term assessments of the costs and benefits of supply resources must also make a fair comparison.

The technical or economic potential of energy efficiency or demand response is typically much greater than can be acquired in a short period by a new program, and not all customers will make the economically preferred choice even once the program is mature. The achievable potential takes these practical considerations into account. Policymakers in 26 U.S. states have set explicit policies that utilities must acquire all available energy efficiency potential over time or have set quantified targets for

demand-side resource acquisition informed by potential studies;[8] demand response has not yet generally received the same level of regulatory and policy scrutiny.

The Pacific Northwest

One region that has taken a comprehensive look at supply and demand-side resources is the Pacific Northwest. As we will see, the electrical characteristics of the region are similar to Québec's, and they indicate how a very open planning process can perform in a similar energy context. The Northwest Power and Conservation Council (NWPCC) coordinates energy and water resource planning in the region. Its mission is "to ensure, with public participation, an affordable and reliable energy system while enhancing fish and wildlife in the Columbia River Basin."[9] Hydropower from the Columbia River Basin is the region's primary electric resource, accounting for over 55 percent of the region's electric energy. Wind is both the region's fastest growing resource and the source of significant integration challenges.[10] Careful management of electric loads has been a hallmark of the region's approach throughout the NWPCC's seven regional power plans (now conducted approximately every five years), as the region seeks to maximize the use of hydropower while maintaining healthy river ecosystems.

The Northwest region covered by the NWPCC has a peak load of about 30–31 GW, which occurs in winter. This is projected to grow to 32–36 GW by 2035, with the residential and commercial sectors accounting for the bulk in demand growth.[11] The seventh Northwest Power Plan[12] was completed in 2016 and concludes that demand-side resources can meet all load growth through 2030, even after accounting for coal plant retirements. These resources are primarily energy efficiency, with demand response identified as a key resource to handle critical water and weather conditions.

The NWPCC and the Bonneville Power Administration (BPA), which coordinates transmission and hydroelectric generation in the Northwest, have found that the region is pushing up against the limits of variation in hydroelectric output to accommodate the variation in load and variable renewable generation. This is the primary driver of the need for demand response in the region. While the region is winter peaking, the hydroelectric flexibility is more reduced in the summer, due to the seasonality of river flows. This means the region is interested in both winter and summer DR capacity.

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[8] Seven of the 26 states have requirements to achieve *all* cost-effective energy efficiency; the remainder have quantified targets. American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standard (EERS) Activity Policy Brief*, January 9, 2017. http://aceee.org/policy-brief/state-energy-efficiency-resource-standard-activity

[9] https://www.nwcouncil.org/about/mission/

[10] NWPCC Seventh Northwest Power Plan, page 2-4.

[11] NWPCC Seventh Northwest Power Plan, page 1-4.

[12] The NWPCC's Seventh Northwest Power Plan is available at https://www.nwcouncil.org/energy/powerplan/7/plan/

The Seventh Northwest Power Plan includes a careful analysis of demand response in the region. This analysis began with a potential study[13] which identifies the summer and winter potential of technologies or measures in the residential, commercial, and industrial sectors. The potential study differentiates between measures available with "base" demand response and those available with "smart" demand response, as well as the potential for balancing (offering dynamic loads to balance changes in renewable generation). The study looked out to 2030 and identified the potential available as it changes over time. Through this process, the NWPCC identified more than 4,300 MW of potential, of which 1,500 MW was available at costs of less than $25 per kW-year.[14]

The NWPCC uses an extensive stakeholder process to vet study inputs and shape the plan. This includes the Pacific Northwest Demand Response Project, a collaborative effort led by the NWPCC and the Regulatory Assistance Project that began in 2005. Its membership meets approximately annually to review regional progress on demand response in the context of the NWPCC's planning responsibilities. Among other things, it reviewed the potential study and the planning methodology that the NWPCC used for incorporation of demand response into its plan. The Seventh Northwest Power Plan recommends a DR Advisory Committee, which has since been formed. It includes representatives of the NWPCC, investor-owned and public utilities, state agencies, non-governmental organizations, and vendors.[15] Its scope is the following:

- "Development and implementation of Action Plan items for the Power Plan
- Defining implementation barriers and developing strategies to overcome them
- Determining near-term and long-term achievability rates
- Understanding the regulatory environment
- Quantifying demand response program costs and savings
- Development of an avoided cost methodology" [16]

The NWPCC uses a stochastic modeling methodology that accounts for variation in hydroelectric resource, weather, resource costs, and load. This allows them to plan for robust solutions that are cost-effective in a wide range of futures, not simply a median expected load situation. In the Seventh Power Plan, the NWPCC identifies that 600 MW of DR capability is required for least-cost capacity needs by

[13] Available at https://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

[14] Seventh Northwest Power Plan, page 1–10.

[15] The current membership of this committee may be found at https://www.nwcouncil.org/media/7150627/drac-members-2016-2018.pdf

[16] https://www.nwcouncil.org/energy/dr/drac-home

2021 in nearly all futures. It will determine in three years if the region is making "sufficient progress" toward this goal.

The NWPCC planning process is a model in another respect as well: it builds its demand-side forecasts from the achievable potential, rather than "bottom up" from existing programs. As a result, the load forecast it uses in supply-side planning already reflects an aggressive energy efficiency program that achieves all available cost-effective efficiency potential. The achievable potential considers the ramp times for new programs and the limited pace of customer adoption (e.g. limited by the lifetime of appliances). Exceptional utility programs can exceed the achievable potential. In fact, northwestern utilities achieved 125 percent of the energy efficiency planned for in the previous (sixth) Northwest Power Plan.[17]

Building a plan from the identified potential is essential when looking out to decadal horizons, because the form of programs and technology available will shift over time. It is clearly a superior technique to assuming programs will maintain the same form throughout a long period. Revisiting the potential and goals on a regular basis, such as every five years for the NWPCC, ensures that changes can be taken into account. While the maturity of energy efficiency analysis allows this process to take place more clearly for energy efficiency than for demand response in the Northwest, lessons learned apply to both.

Portland General Electric

One of the utilities that would be responsible for developing the 600 MW of demand response envisioned in the NWPCC's Seventh Power Plan is Portland General Electric (PGE). PGE commissioned a DR potential study in 2015.[18] This update does a clear job of defining and distinguishing the achievable potential from the technical or economic potential. To estimate what is achievable for PGE, the study assumes PGE can achieve a level of participation that would put PGE at the 75th percentile among all similar utility programs. PGE also has near-universal AMI, so this study comprehensively treats the opportunity from different kinds of rate-based DR programs.

4.3. Taking Advantage of Technology

Advanced metering infrastructure

AMI is a foundational component of DR programs based on time-varying rates. Time-varying rates provide a price signal to customers to encourage reductions in consumption during peak hours. AMI collects and records customer consumption on an hourly or sub-hourly basis, enabling utilities to implement sophisticated rate structures that better reflect the costs of energy production and delivery.

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[17] Seventh Northwest Power Plan, page 2–15.

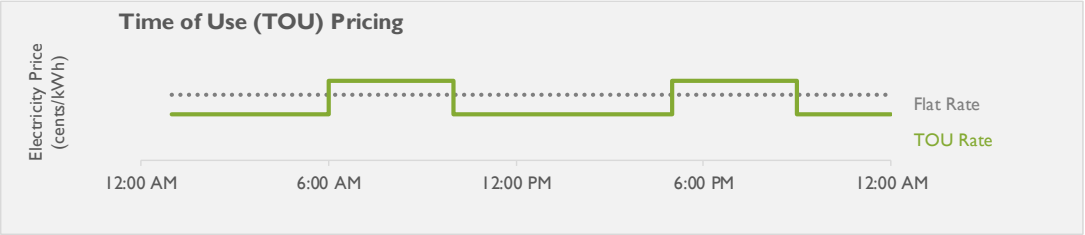
[18] Hledik, R., A. Faruqui, and L. Bressan. 2016. "Demand Response Market Research: Portland General Electric, 2016 to 2035" Preparted by Brattle Group. Available at: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-02-01-demand-response-market-research.pdf?la=en.

AMI also supports additional technologies, such as web-based portals that allow customers to view their hourly energy usage, compare their usage to their neighbors, evaluate other energy rates, and receive information about ways to better manage their electricity consumption. These capabilities are described below.

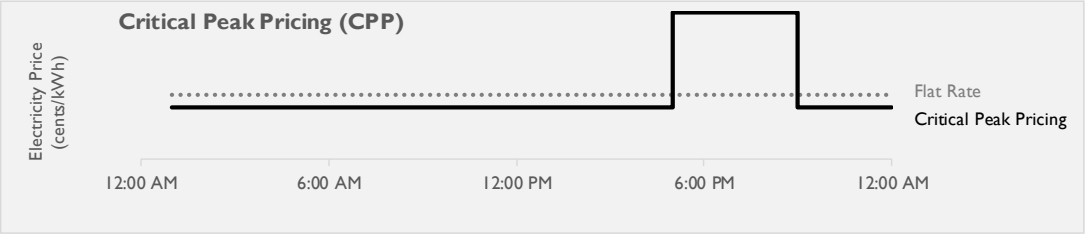
Time-varying rates

An important lesson from other programs is that customers tend to want to retain control of their electricity use. Ensuring that control has proven to be a key component in encouraging expanded customer participation in DR programs. Time-varying rates allow customers to determine how they would like to respond, based on a price signal from the utility. The most common forms of time-varying rates are described below, along with a stylized depiction of how each rate could be implemented.

- *Time-of-Use (TOU) Rates:* TOU rates consist of two or more pricing tiers, based on pre-set time periods. Electricity is priced higher during hours when the peak is more likely to occur, and lower during hours that are generally off-peak. An advantage of this type of rate structure is that it has low financial risks to customers, because the pricing is known ahead of time and customers choose whether to curtail their electricity use.



- *Critical Peak Pricing (CPP):* This rate structure is often used in conjunction with TOU rates, but can be used with an otherwise flat rate structure as well. Critical peak pricing implements a very high price tier that is only triggered for very specific events, such as system reliability or peak electricity market prices.[19] The timing of the events is generally not known until a day in advance, and the events typically last for only 2–6 hours.

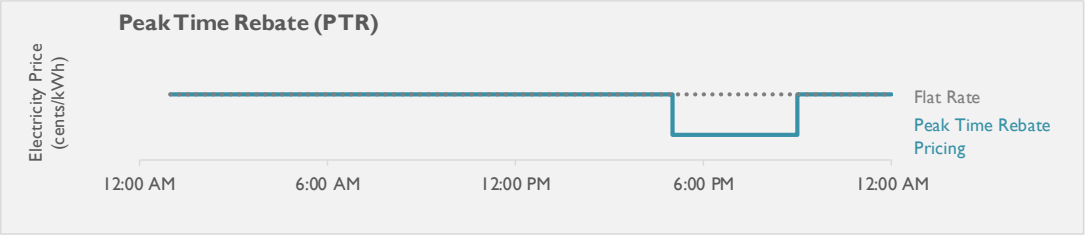


- *Peak Time Rebates (PTR)*: A peak time rebate program is similar to critical peak pricing, except that customers earn a financial reward for reducing energy relative to a baseline, instead of being subject to a higher rate. As with critical peak pricing, the number of

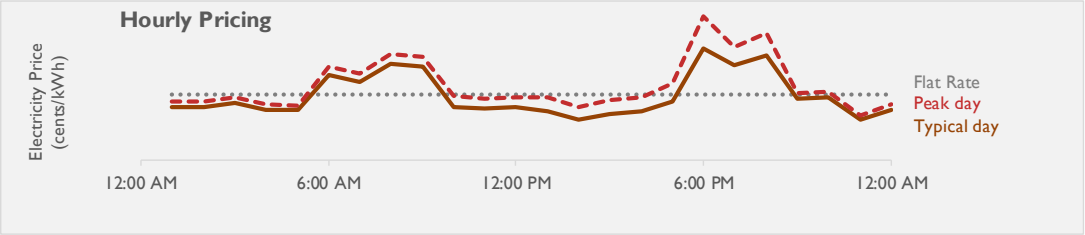
[19] Hledik, R. et al., 2016.

event days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.[20] While PTR programs tend to be widely accepted by customers, they have two drawbacks relative to critical peak pricing:

- Baseline usage can be difficult to determine with accuracy. For example, a customer may earn a reward simply because the customer was out of town on the day of the event rather than because the customer actively reduced their electricity consumption in response to the event.
- Peak time rebates tend to result in lower reductions than critical peak pricing. Customers generally respond more strongly when they are faced with paying more for consumption during peak hours than when they are offered a reward for lowering consumption.



- *Real-Time Pricing and Hourly Pricing:* These rates charge customers for electricity based on the wholesale market price rather than a preset rate schedule.[21] Rates fluctuate hourly or in 15-minute increments, reflecting changes in the wholesale price of electricity. Customers are typically notified of prices on a day-ahead or hour-ahead basis.



As part of its "Heure Juste" pilot, HQD conducted a TOU ("Réso") pilot and a TOU with critical peak pricing ("Réso+") pilot during the winters of 2008/2009 and 2009/2010. Customers on both the Réso and Réso+ tariffs faced on-peak prices approximately $0.02/kWh higher than off-peak prices, but customers on the Réso+ tariff also faced a critical peak price more than three times higher than the off-peak price.[22]

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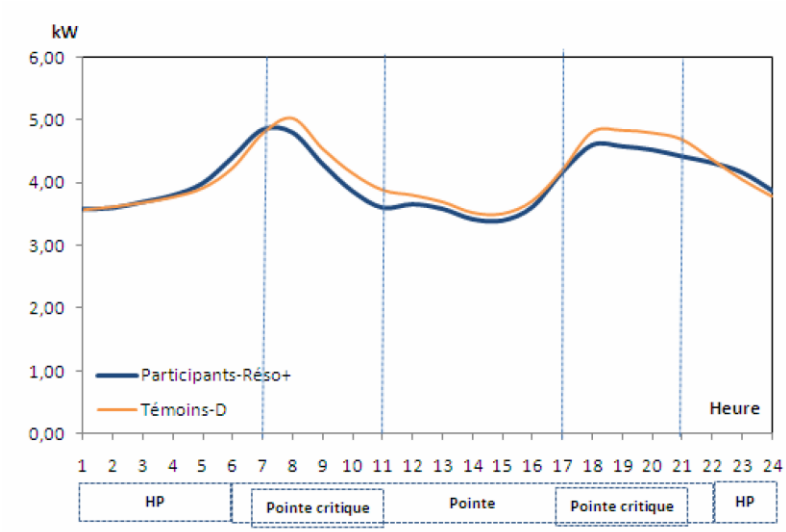
[20] United States of America. Federal Energy Regulatory Commission. *Assessment of Demand Response and Advanced Metering.* Washington D.C.: United States, 2010.

[21] Ibid.

[22] With the exception of the first 15 kWh, which were priced lower.

The pilot's results demonstrated that customers on both tariffs decreased load in response to the price signals, but the reductions of customers on the Réso tariff were not statistically significant. Customers facing critical peak prices reduced load during peak periods the most, with average reductions over the two winters of 6 percent (0.27 kW).[23] The average load profile on critical peak days for customers participating in the pilot is shown in the graph below in blue, with non-participating customers in orange.

Figure 8. HQD critical peak pricing pilot load profiles



Source: HQD, Rapport Final Du Projet Tarifaire Heure Juste, Demande R-3740–2010, August 2010.

Customers participating in the pilots generally reported a positive experience and would elect to participate in such a rate structure in the future.[24]

Experience in other jurisdictions

The results of HQD's TOU and CPP pilot are generally in line with what has been observed in other jurisdictions, although the magnitude of the reductions is on the low end of the scale. The graph below shows the results of 163 treatments in 34 projects on four continents from The Brattle Group's database of pricing studies.[25] As shown in the graph, critical peak pricing typically delivers the greatest load reductions, while TOU rates and peak time rebates exhibit more modest impacts.

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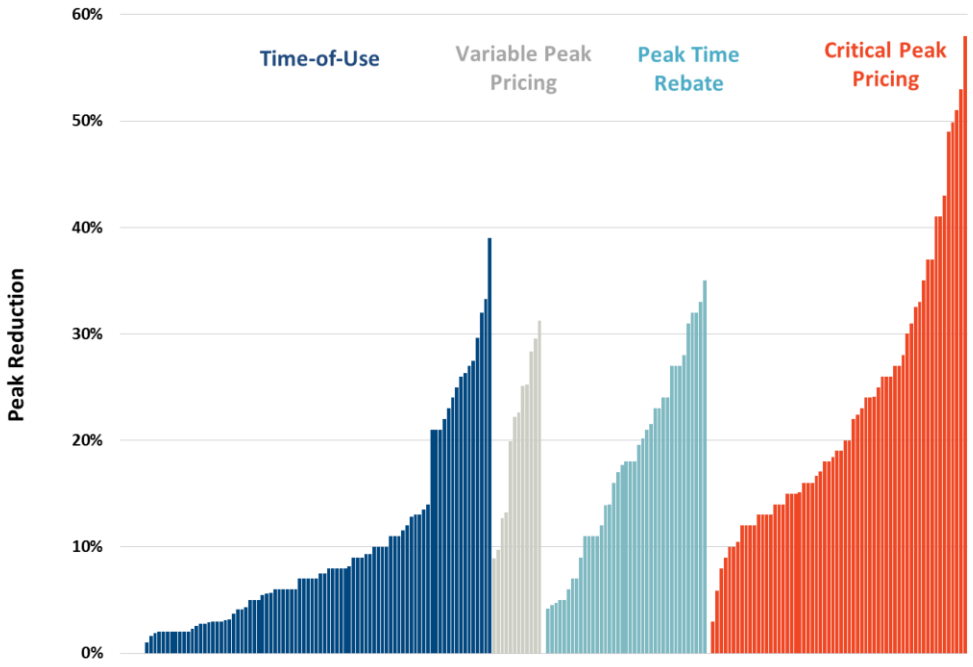
[23] HQD, *Rapport Final Du Projet Tarifaire Heure Juste*, Demande R-3740–2010, August 2010, page 30.

[24] HQD, *Rapport Final Du Projet Tarifaire Heure Juste*, Demande R-3740–2010, August 2010, page 22.

[25] Faruqui, A. and S. Sergici. 2013. "Arcturus: International Evidence on Dynamic Pricing" Prepared by Brattle Group. Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2288116.

Figure 9. Residential peak reductions by time-varying rate type



Source: Faruqui, Ahmad. "Arcturus." The Brattle Group.

There are several factors that may contribute to different results in Québec relative to other jurisdictions:

- First, many of the studies in the graph above focused on shifting peak summer usage in the United States, particularly air conditioning load. Customers may be less able to shift heating load to off-peak time periods.
- The ratio of peak to off-peak prices plays a large role in encouraging customers to shift load, with higher ratios resulting in greater load shifting. HQD's ratio of peak to off-peak prices in the Réso program was approximately 1.5:1, whereas most of the treatments in Brattle's database have price ratios of 2:1 or higher. (Réso+ had a higher ratio, about 3:1, for critical peak events.)
- Shorter peak periods make it easier for customers to shift load. Many TOU programs feature peak periods of 6 hours or less; in contrast, HQD's peak period was set for 16 hours (from 6 am to 10 pm), with critical peak periods occurring up to 8 hours per day.

  Frequent or consecutive critical peak pricing events can result in "fatigue" setting in. Many jurisdictions cap the number of events at 10, and often only call a few critical days per year. During its pilot, HQD called more than 20 critical peak periods (each of 4 hours in duration) over 13 or more days. In addition, HQD reports that customer response in 2009/2010 was lower than the previous year, possibly in part due to February 2010 having four consecutive event days, each with two critical peak periods of 4 hours each.

- The presence of enabling technologies, such as programmable two-way communicating thermostats has been found to boost customer response rates.[26] HQD's pilot included a display, which was found to increase load shifting slightly.

Baltimore Gas and Electric Peak Time Rebate

Baltimore Gas and Electric is the first large utility in the United States to make a dynamic, peak-focused rate-based rebate program the default for all residential customers.[27] The rebate structure of PTR made it more acceptable to customers to make PTR the default than critical peak pricing would have been. The program gives credits of $1.25 per kWh for reductions in energy consumption, relative to an algorithmic baseline, during "Energy Savings Days." BGE advertises that participants can save $5–8 per Energy Savings Day.[28] While our Synapse colleagues have questioned whether $1.25/kWh is the correct value for the program to maximize cost-effectiveness,[29] the program is nevertheless quite successful at reducing summer peaks. By quantifying these savings well, this "non-dispatchable" demand response program, which is coupled with BGE's air conditioner cycling load control program, has achieved almost the level of certainty achievable from load control DR. After four years of pilots, BGS is confident enough in the peak savings from the program that it has bid the resulting savings into the PJM capacity market.

Networks and smart appliances

Home or business area networks allow customers to connect multiple wi-fi enabled devices to help monitor and control electricity usage. Software on these networks allows customers to set preferences for when their appliances operate, and it then uses these preferences to control the equipment. For example, the software can be set to respond to electricity price signals and automatically adjust consumption according to the customer's preferences during peak and critical peak price periods.[30]

Appliances connected to home area networks may also receive DR commands from the utility. Customers who opt in to such DR programs allow the utility to make small adjustments to the energy consumption during a small number of events each year in exchange for a payment or rebate from the utility. For example, Consolidated Edison in New York City provides an $85 rebate for customers who

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[26] Faruqui and Sergici. 2013.

[27] https://www.greentechmedia.com/articles/read/bge-pushes-towards-one-million-peak-time-rebate-customers

[28] https://www.bge.com/WaysToSave/ForYourHome/Pages/EnergySavingsDays.aspx

[29] Chang, M. 2016. Direct Testimony of Maximilian Chang in the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates. Docket No. 9406. http://www.synapse-energy.com/sites/default/files/Testimony-of-M-Chang-BGE-Rate-Case-15-120.pdf

[30] For example, customers enrolled in dynamic pricing at Oklahoma Gas & Electric use Energate smart thermostats to adjust energy use automatically. *See:* http://www.elp.com/articles/2013/06/og-e--energate-continue-demand-response-program.html

enroll in their two-year DR program that allows the utility to adjust their thermostat a maximum of 10 times each year.[31]

Standards

Standardization can lower barriers and reduce costs in DR program design and participation. There are two emerging standards of particular note: USNAP and OpenADR.

Universal Smart Network Access Port

Universal Smart Network Access Port (USNAP or CTA-2045) is an emerging standard published by the Consumer Technology Association in 2013 for a "modular communication interface for energy management." In effect, this is a standardized hardware plug and associated standards for communication across that plug, akin to USB or VGA. It would be built into appliances such as water heaters, thermostats, or air conditioners. A utility can then provide a communication module that plugs into the appliance's port and receives communications from the utility telling it when to change its behavior; the module may also send messages back to the utility. The use of a standardized port will allow appliance manufacturers to develop products that are DR-ready and able to be used in multiple utility territories. It will also allow utilities to enable those appliances to participate in DR programs with the addition of a single standardized device, rather than developing custom means of interfacing with each appliance type. The standard port allows the utility to provide interfaces that communicate via their choice of radio frequency, Wi-Fi, power-line carrier, or Zigbee. Standardization should also allow lower costs for all parties.

The Electric Power Research Institute (EPRI) ran a field demonstration of the USNAP standard (then called CEA-2045) in 2014–15 along with 21 utility and program partners.[32] One of them, PGE of Oregon, has been a leading utility for the deployment of USNAP-enabled hot water heaters for demand response. In late 2015 and early 2016, PGE tested 14 smart water heaters with its employees, calling DR events throughout the winter peaking season.[33] PGE has since designed a program, launching this year, to deploy an increasing number of enabled water heaters (eventually more than 5,000) over the next several years in the multi-family residential market.[34] AO Smith, one of the world's largest water heater manufacturers, produces a line of water heaters with USNAP capability built in.[35]

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[31] Consolidated Edison, "Register Your Smart Thermostat and Get Up to $110," *ConEdison*, 2017, https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/bring-your-thermostat-and-get-$85.

[32] http://smartgrid.epri.com/doc/ICT%20Informational%20Webcast%20CEA-2045%2009APR2015.pdf

[33] http://aceee.org/sites/default/files/files/pdf/conferences/hwf/2016/Keeling_Session7C_HWF16_2.23.16.pdf

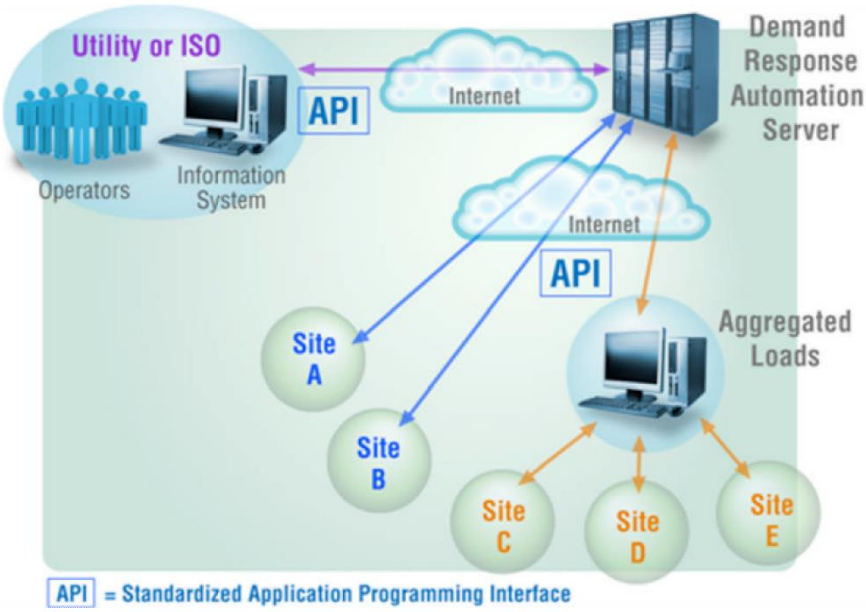
[34] http://aceee.org/sites/default/files/pdf/conferences/hwf/2017/Naleway_Session3A_HWF17_2.27.17.pdf

[35] https://www.hotwater.com/lit/spec/res_elec/aosre50600.pdf

OpenADR

OpenADR is a communication standard for automated demand response (Auto-DR or ADR). OpenADR "defines the expected behavior when exchanging DR event related information" between utilities, grid operators, and customer end-use systems.[36] This standard allows interoperability between different control systems. Specifically, it avoids the need for a custom solution to communicate between a particular utility control software system and a particular manufacturer's building or facility energy management system.

Figure 10: OpenADR API diagram



Source: The OpenADR Primer.[37]

California's building energy code, referred to as "Title 24" (effective January 1, 2014), requires DR capabilities in lighting and HVAC in buildings over 10,000 square feet, including a 15 percent reduction in lighting energy use.[38] (California's peaks are summer peaks, when daylight is an option.) OpenADR is a compliance strategy for this building requirement, and all three of California's major utilities have announced support for the most recent version of OpenADR (earlier versions of which they have been using since 2007).

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[36] http://www.openadr.org/assets/adr_dtech_datasheet_v2.pdf

[37] http://www.openadr.org/assets/docs/openadr_primer.pdf

[38] http://www.globenewswire.com/news-release/2013/06/25/556191/10037596/en/OpenADR-Helps-Building-Owners-and-Operators-Meet-Title-24-California-Compliance-Requirements-For-Connecting-Buildings-to-the-Smart-Grid.html

4.4. Measure and Customer Diversity

Utility DR programs rely on a wide range of resources, depending on the resources available within the customer base of the utility and the timing and character of the utility's needs. This section discusses the different kinds of measures seen most commonly in utility DR programs. It also identifies some programs or approaches that have been particularly successful. It concludes with a discussion of up and coming opportunities in distributed storage and EVs.

Heating, ventilation, and air conditioning (HVAC)

Direct load control programs been used for decades and have often focused on HVAC systems. These programs involve the installation of control technologies on a customer's appliance. They allow the utility to cycle the appliance during peak hours in exchange for a financial incentive to the customer. While these programs have often focused on air conditioners, there has also been some attention given to space heat. For example, PGE's 2016 DR potential study found that direct load control would likely be cost-effective for residential and small commercial customers when customers have both electric heat and air conditioning.[39]

One emerging area of interest for cost-effective residential HVAC DR programs is a "bring your own thermostat" (BYOT) option. Customer interest in smart thermostats, driven by desire to remotely control heating and cooling systems by smart phone, has resulted in deployment of these thermostats outside of utility programs. They are also deployed by utility programs as energy efficiency measures, without explicit expectation of DR program participation. Once the thermostat is installed, however, costs to enable DR capabilities in the household are substantially lower.

Water heating

Electric water heaters are essentially thermal batteries. While the use of hot water results in electric consumption, those two events do not need to be simultaneous, resulting in a highly capable DR resource. Customers' general lack of engagement with hot water heating is a strength in this regard: if a utility can assure customers that their quality of hot water service will not be impaired, customers have shown a willingness to turn over control to the utility. Water heater control has been deployed at scale in the United States. For example, the four utilities of Duke Energy, which serve customers in six states, control two million water heaters.[40]

Utility use of hot water heaters spans a wide range with respect to the dynamism of the engagement with each water heater. At one end of the spectrum are scheduled water heater controls: water heaters

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[39] Ryan Hledik, Ahmad Faruqui, and Lucas Bressan, "Demand Response Market Research: Portland General Electric, 2016 to 2035" (Brattle Group, January 2016), https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-02-01-demand-response-market-research.pdf?la=en.

[40] https://www.bpa.gov/EE/NewsEvents/presentations/Documents/DER%20Utility%20Brown%20Bag%2020161020%20final.pdf, slide 12

are simply turned off for a number of hours each weekday on a set schedule (typically 4 or 8 hours at each window; large thermal storage water heaters may be allowed to charge only during an 8-hour overnight period). These times may correspond to morning and evening peaks in the winter, and to an afternoon peak in the summer. This almost does not qualify as demand response, because it is a change in the baseline behavior of the appliance. Utilities may divide the water heaters into groups that turn back on at separate times to ease recovery peaks. Scheduled recovery also allows the utility to plan for these changes in load with supply ramps.

At the next level of dynamism are one-way communications that trigger water heater shutoffs; these may be communicated via radio frequency or power line carrier communication methods. Utilities may address all water heaters as a block, or address them individually. Individual treatment allows customers to ask for their unit to be turned back on for a "comfort bump" and the utility to re-engage the heaters in waves, avoiding a demand spike at the end of the DR event.

Two-way communications are a relative new entry into this space. They allow the utility to provide both higher quality service (by ensuring that the water is fully hot before the beginning of a DR event) and more effectively use the heater for ancillary services.[41] In the PJM region, for example, water heaters provide 69 percent of the 65 MW of demand response participating in wholesale frequency regulation service and 9 percent of the 514 MW of synchronous reserve provided by demand response.[42]

In our research and conversations with industry experts, we have not encountered any concern regarding legionella or other public health concerns associated with the use of water heaters as a grid resource.

Great River Energy

Great River Energy (GRE) is a Minnesota generation and transmission cooperative, providing service to 28 member distribution cooperatives. Its members serve about 665,000 customers (1.7 million people). GRE operates five residential load management programs: cycled air conditioning, interruptible water heating, electric thermal storage (ETS) water heater, ETS space heating, and dual-fuel heating.[43] Over 200,000 customers participate in one of these programs, including over 100,000 in one of the water heater programs.[44] This means that about 15 percent of GRE's members' customers participate in a

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[41] One-way communication can facilitate ancillary services as well, but it is more complex due to the uncertainty regarding the state of the water heater.

[42] https://pjm.com/~/media/markets-ops/dsr/2017-demand-response-activity-report.ashx, page 9-10

[43] GRE also has programs for residential and commercial EVs, interruptible irrigation, and interruptible commercial and industrial with and without customer-sited backup generation. See http://greatriverenergy.com/we-use-energy-wisely/great-river-energy-load-management-programs/.

[44] 67,000 customers participate in the thermal storage water heater program, in which electricity is only supplied to the water heater between 11pm and 7am each day. These customers have large (80–120 gallon) tanks that last them all day. GRE considers this to be the equivalent of a 1 GWh battery. About 40,000 customers with smaller tanks participate in a peak shaving water heater program in which heaters are shut off for 5 to 7 hours.

water heater program. GRE primarily controls these water heaters to shift loads from high-cost periods to low-cost periods in the wholesale markets. They are also available to respond to system emergencies and provide capacity to meet resource adequacy requirements.[45] The predictable nature of the water heaters allows GRE to plan for the load increase that comes at the end of a DR event and when the thermal storage systems start to recharge each night.

GRE has been able to get high participation rates through consistent program availability over nearly four decades, with customer engagement focused on water heater replacement and new construction. About 70 percent of the new housing in Minnesota has been in their service territory, and about a third of those new homes have signed up for a controlled water heater program.[46]

GRE partnered with the National Rural Electric Cooperative Association, Natural Resources Defense Council, and Peak Load Management Alliance to commission a report from the Brattle Group, "The Hidden Battery: Opportunities in Electric Water Heating"[47] which indicates that "community storage" in the form of water heaters has the potential to be a significant grid resource for peak shaving, load shifting with thermal storage, and fast response. The report recommends that programs be tied to the needs of the utility and market in which it operates. For example, where fast response is not necessary or aggregated demand resources are not allowed to contribute, the infrastructure cost for two-way communication is unlikely to be cost-effective. GRE is requiring its members to use two-way communication based on their AMI networks within the next eight years, allowing time for their member distribution utilities to transition.

Bonneville Power Administration two-way communication pilots

Bonneville Power Administration (BPA) and PGE are testing 600 controlled water heaters with two-way communication using the CTA-2045 communication protocol. The objectives of the pilot are to demonstrate a 24/7 control regime to shape load and account for wind forecast error, and to determine the appropriate on-peak kW reduction that can be obtained with these appliances.[48] PGE plans to build on this technology pilot with a market pilot in 2017–19, eventually reaching over 5,000 units deployed.[49]

Interruptible loads

Large industrial users are often capable of supplying large amounts of demand response. Historically, this has taken the form of load reductions during emergency conditions. More recently, it has evolved to include the provision of ancillary services (such as balancing and frequency regulation), which facilitates

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[45] http://greatriverenergy.com/wp-content/uploads/2015/10/when_why_control.pdf

[46] Gary Connett, Great River Energy, personal communication, March 23, 2017.

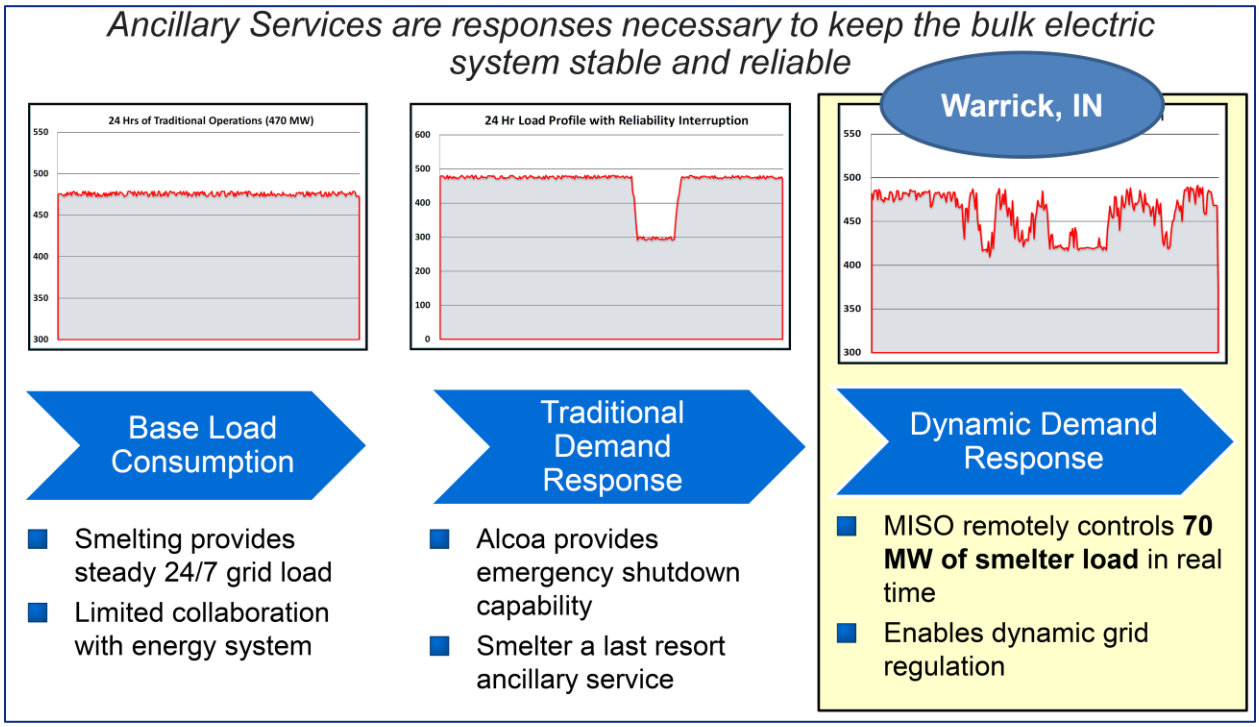
[47] http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

[48] https://www.bpa.gov/Doing%20Business/TechnologyInnovation/TIPProjectBriefs/2017-DR-TIP-336.pdf

[49] http://aceee.org/sites/default/files/pdf/conferences/hwf/2017/Naleway_Session3A_HWF17_2.27.17.pdf

the integration of variable renewable resources. An example is Alcoa, Inc., a producer of alumina, primary aluminum, and fabricated aluminum products. As shown in Figure 11 below, Alcoa's smelters in Warrick, Indiana, have steady baseload electricity consumption. This can be interrupted to provide 150 MW of load reduction for reliability needs (middle graph), or it can be directly controlled by the utility or system operator on an on-going basis to provide 70 MW of regulation or other ancillary services.[50]

Figure 11. Alcoa demand response



Source: DeWayne Todd, "They Said It Couldn't Be Done: Alcoa's Experience in Demand Response," March 7, 2013.

Distributed electric storage

Storage deployed by customers for on-site reliability or demand charge reduction can also be used by an enterprising utility as a capacity or peak-shifting resource. One of the primary markets for distributed energy storage to date has been to businesses who have the goal of reducing their demand charge. However, if the customer's demand does not peak at the time of system peak, this resource would be underutilized for system cost reductions. As the capacity of such storage increases, this could become an

[50] DeWayne Todd, "They Said It Couldn't Be Done: Alcoa's Experience in Demand Response," March 7, 2013, http://texasiof.ceer.utexas.edu/PDF/Documents_Presentations/Energy_Forums/Forum%203-7-13/2%20Alcoa%20Experience%20in%20Demand%20Response%20-%20Texas%20Industrial%20Energy%20Management%20Forum.pdf.

important resource for utility planning, provided a utility can engage customers to achieve some level of control over the storage or use peak-coincident rate structures to encourage its use.

An emerging market for residential-scale storage, primarily in place of a generator for power continuity, provides another kind of new resource. Green Mountain Power of Vermont has partnered with Tesla to place up to 500 Powerwall battery systems in customers' homes.[51] Each system can store 7 kWh and put out 2 kW continuously or 3.3 kW peak. Participating customers will be able to ride through storm events or other disturbances. (Many of these customers are also expected to have solar PV, allowing battery recharge even when the grid is down.) Customers will either purchase the storage outright or pay a monthly service fee. If they buy the storage, they can get a monthly bill credit of $31.76 in exchange for allowing the utility to control the unit to reduce system costs (such as capacity and transmission costs). If they opt for the monthly service arrangement ($1.25/day), the utility retains the right to control the unit as part of the terms of service.

Electric vehicles

Residential electricity rates typically are time-invariant, charging customers the same price per kWh, regardless of when that energy is consumed. While such time-invariant energy rates may be acceptable during most hours of the year, they fail to provide customers with important price signals during peak hours when the cost to provide electricity spikes. This lack of efficient price signals is problematic for standard residential usage, but becomes a critical flaw as EV adoption increases. EVs consume significant amounts of energy. For example, a standard Level 2 EV charger can easily double the load of an entire household.[52]

With time-invariant rates, residential customers often charge their EVs in the late afternoon and evening hours.[53] For example, Figure 12 shows an analysis by Avista Utilities in Washington state illustrating that most residential charging occurs between the hours of 4 pm and 10 pm with hourly load exceeding 1 kW per vehicle during the early evening hours.

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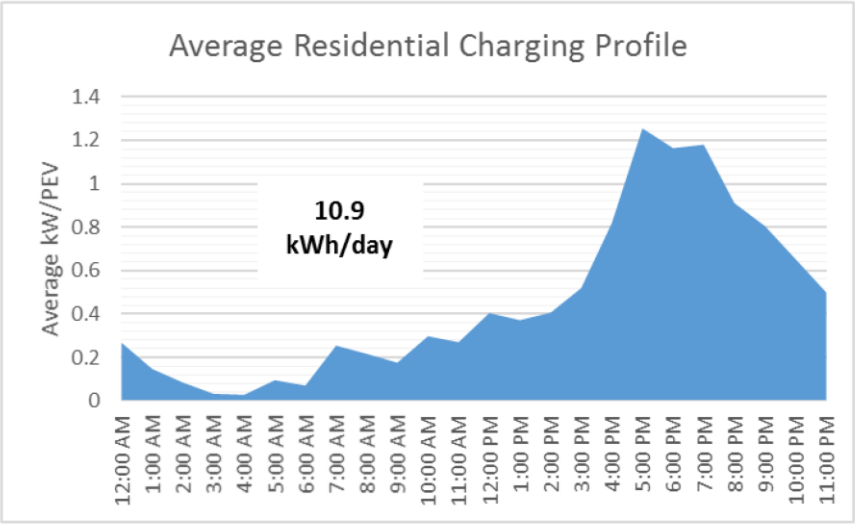
[51] http://products.greenmountainpower.com/product/tesla-powerwall/

[52] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

[53] See, for example, SDG&E Chart 9, in SCE, PG&E, SDG&E, "5th Joint IOU Electric Vehicle Load Research Report," 13-11-007, *Load Research Report Compliance Filing of Southern California Edison Company (U 338-E), on Behalf of Itself, Pacific Gas and Electric Company (U 39e), and San Diego Gas & Electric Company (U 902-M), Pursuant to Ordering Paragraph 2 of D.16-06-011*, December 30, 2016, 16-06–011.

Figure 12: Avista average residential charging profile



Source: Avista Corp., Avista Utilities Quarterly Report on Electric Vehicle Supply Equipment Pilot Program, Docket No. UE-160082, February 1, 2017, p. 11.

Such charging profiles would likely exacerbate peak demand on HQD's system, potentially to an even greater extent than anticipated in HQD's filing, which assumes only 0.6 kW per EV. Utilities in many jurisdictions have implemented a variety of DR programs to cope with this challenge and incentivize customers to change their charging habits. These programs range from time-varying rates for EV owners to utility direct control of EV charging. They are typically implemented for residential or workplace installations where vehicles are parked for many hours, rather than public installations where EVs are only parked for a few hours.

Time-varying rates

Time-of-use (TOU) rates are one of the most common forms of time-varying rates implemented for EV customers,[54] and researchers have repeatedly found these rates to be effective at reducing costs and emissions. A pilot study in San Diego concluded that TOU rates are very effective at encouraging customers to charge during low-cost times—the rate of overnight charging reached 90 percent for customers facing high ratios of off-peak to peak prices.[55] This shift in electricity usage is estimated to

[54] In the United States, at least 17 large investor-owned utilities that have implemented time-of-use rates for EV customers.

[55] Nexant, 2014.

result in significant savings if applied across the states, potentially saving California $1.2 billion between 2015 and 2030.[56]

Interruptible load

Since 2015, PG&E in California has implemented a demand response EV pilot program with BMW. The pilot requires BMW to provide a minimum of 100 kW of capacity at any given time in the form of day-ahead or real-time energy services. Between July 2015 and June 2016, BMW reliably provided demand response in 134 DR events, meeting performance requirements for 94 percent of the events called. Customers participating in the pilot have reported high levels of satisfaction, with 92 percent indicating they are satisfied with the program.[57]

Similarly, Avista plans to implement a pilot that curtails charging during peak demand hours, while also ensuring that the EV is fully charged by the time the customer needs to use the vehicle.[58] Avista will make use of customer notifications and provide the right to opt out of any event.

Vehicle to grid (V2G)

EVs are effectively storage devices. When EVs draw electricity from the grid, that electricity is not immediately used to propel the vehicle. Instead, the electricity is stored in the vehicle's battery for later use. When the vehicle is not being used by the customer, it could be tapped directly by the utility or system operator to either inject electricity into the grid when needed, or draw electricity from the grid when there is overgeneration. Such vehicle to grid (V2G) integration has been tested in several locations in the United States, and it is now fully operational in Denmark.[59]

4.5. Customer Engagement and Communication

Traditional utility practice, focusing on static rate designs and supply-side resources, provides no monetary or psychological reward for customer engagement. DR programs, on the other hand, provide an opportunity for utilities to engage with customers "beyond the bill." Demand response is a relatively clear concept to explain to customers and provides an opportunity for customers to contribute to the broader good (reducing costs for everyone) while also, depending on program design, saving money

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[56] Energy and Environmental Economics, Inc. 2014. "California Transportation Electrification Assessment Phase 2: Grid Impacts." Available at https://www.researchgate.net/publication/267694861.

[57] PG&E, "Pacific Gas and Electric Company Smart Grid Annual Report – 2016," Smart Grid Technologies, Order Instituting Rulemaking 08-12-009, CPUC, 2016.

[58] Avista Corp., Cover Letter to the Washington Utilities and Transportation Commission, Re: Tariff WN U-28 (New Tariff Schedule 77), Docket UE-160082, January 14, 2016.

[59] Frederiksberg Forsyning in Denmark purchased a fleet of cars from Nissan and is using Enel charging stations. The software to control the vehicles was developed at the University of Delaware and is being licensed by Nuvve in Europe. *See:* Karen Roberts, "UD-Developed V2G Technology Launches in Denmark," *UDaily*, August 29, 2016, http://www.udel.edu/udaily/2016/august/vehicle-to-grid-denmark/.

themselves. Customer engagement on one front, such as demand response, can provide an opportunity to engage on others, such as energy efficiency or consideration of energy supply or transmission issues. Empowering customers also provides an opportunity to activate new markets and innovative firms as customers look for assistance to maximize their return or meet their unique needs. Participation in demand response also commonly requires the customer to make an investment with the expectation of return over time. Offering predictable or guaranteed programs (such as multi-year contracts) respects the customer's contribution and expectations.

Behavioral demand response

It is common practice for utilities to make public appeals on peak days, asking customers to constrain energy use during times when the grid is stressed (whether that is a summer afternoon in southern California or a winter evening in Québec). However, to understand such appeals, plan for their effects, and measure whether their effectiveness is changing, their impacts must first be measured. This means explicitly designing tests to measure the effects of appeals.

The design of such a test depends on the mechanisms to be tested. A public appeal (e.g. via the broadcast media) would need to be tested by comparing loads on days with and without appeals but with similar weather (or adjusting the load for weather), after accounting for DR resources deployed through other means (such as interruptible rates). If an appeal is made through email or text message, it can be targeted to particular customers, while other customers do not receive it. This opens the door to a randomized controlled trial experimental design.

Opower Inc. and its utility partners have tested the impacts of purely behavioral demand response using a randomized controlled trail (RCT) approach. RCT assigns some customers to the treatment group—those who will get the appeal to reduce demand—and some to a statistically indistinguishable control group. When the utility contacts the treatment group, the changes in their load relative to the control group provide a measure of the effectiveness of the appeal. Such testing requires AMI, because the utility needs to be able to distinguish both targeted and control-group customers' loads during the DR event from load at other times. In Opower's test of this approach in Glendale, California,[60] they measured a 3.4 percent peak reduction impact attributable to the DR appeal. The impact was even higher among customers already participating in another Opower program.

When peak events are associated with prices (such as through critical peak pricing or peak-time rebates), the impact of appeals may be increased, although the impact of the appeal may be harder to distinguish from the impact of the price change. Engaging customers through direct communications around DR events also provides an opportunity to identify other energy efficiency or DR opportunities with those customers (such as enrollment in direct load control programs).

[60] http://www2.opower.com/l/17572/2015-06-01/22v3lc/17572/104364/Glendale_BDR_Case_Study.pdf

In some cases, appeals may increase the response from DR resources that are contractually obligated to respond at a certain level. HQD experienced this on January 24, 2013, when 307 MW of load responded to an extraordinary appeal. This has been observed on several occasions in Texas. For example, on February 2, 2011, Texas experienced an extreme cold weather event that led the system operator (ERCOT) to deploy 889 MW of Load Resources early in the morning (5:20 am). More than 99 percent of the requested load reduction was achieved. Half an hour later, an additional 140 MW of Load Resources that were not committed also responded to the system-wide request from ERCOT operators.

At 5:48 am, ERCOT activated an additional program of Emergency Interruptible Load Service resources (384 MW). Some additional Emergency Interruptible Load Service resources (83 MW) that were not obligated to respond also made themselves available. Due to the severity of system conditions (as more and more generators failed to operate for a variety of reasons) the Emergency Interruptible Load Service resources remained dispatched for 28 hours. The average Emergency Interruptible Load Service obligation for the entire 28-hour event was 462.8 MW; the average actual load reduction for the entire event was 577.7 MW.[61]

Coupling energy efficiency and demand response customer engagement

When utilities engage with customers, particularly large commercial or industrial customers, they can achieve economies by engaging on several issues at once. In particular, energy efficiency and DR audits draw on very similar auditor expertise. The overlap is even greater in facilities with comprehensive energy management systems. In 2007, National Grid of Massachusetts conducted a pilot program to address a congested area on its grid in Everett, Massachusetts. This program combined assessment of participating facilities for demand response, energy efficiency, and renewable energy potential.[62] National Grid is piloting a DR program this year, and is again equipping its account representatives with information regarding both energy efficiency and demand response in order to maximize customer engagement and savings.[63] National Grid uses contracted efficiency and DR experts for on-site audits, and third-party aggregators will deploy the DR resources.

On a programmatic level, some jurisdictions are incorporating DR and energy efficiency into joint programs.[64] In Maryland, for example, about one third of "EmPOWER" program funding is dedicated to demand response. Pennsylvania's experience with demand response and energy efficiency integration under Act 129 was discussed earlier, and reflects about 10 percent of energy efficiency funding dedicated to demand response. New York utilities plan to leverage marketing and administrative

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[61] ERCOT. "2011 EILS Deployments." QMWG. 2012.

[62] Patil et al.(2007), Case Studies from Industrial Demand Response Audits Integrated with Renewable Energy Assessments," available at http://aceee.org/files/proceedings/2007/data/papers/18_2_110.pdf

[63] Grayson Bryant, National Grid, personal communication, March 24, 2017.

[64] See Buckley (2016), "Putting More Energy into Peak Savings: Integrating Demand Response and Energy Efficiency Programs in the Northeast and Mid-Atlantic," available at http://aceee.org/files/proceedings/2016/data/papers/6_968.pdf, for more information.

resources for efficiency and demand response, even though the programs remain separate for cost recovery and evaluation purposes. The Bonneville Power Administration's "Energy Smart" industrial energy efficiency program has identified opportunities for joint energy efficiency and DR implementation in municipal water, cold storage, and food processing applications.[65]

Activating markets and innovation with third-party DR aggregators

Aggregators or other third parties can play a valuable role in collecting and coordinating demand response for utilities as well as in wholesale markets. Where utility programs or market rules may require a certain compensation or risk structure for each participant, aggregators can collect and shift those risks among participants, hedging across their pool of resources. For example, a particular DR resource may only be willing to be deployed eight times per winter, while a utility program requires up to 20 deployments. Without an aggregator, the resource would be untapped. If an aggregator can combine that resource with others, it can bring that capacity to the system while respecting the customer's needs. Rick Goddard of Rodan Energy Solutions has identified a list of the benefits of aggregators, in the Ontario context:[66]

- "Shoulder prudential requirements on behalf of the contributor to allow them to participate in DR without encumbering their own balance sheets with onerous performance securities;
- Bundle smaller loads that would be unmanageable for the [system operator] to enroll on their own;
- Provide pre-enrollment services to assist organizations of any size without the necessary staff and expertise to properly assess their curtailment potential, develop curtailment strategies;
- Provide the expertise to handle all of the technical and administrative overhead required to enroll and maintain a facility and to navigate the various governmental agencies on the contributor's behalf;
- Provide telemetry to foster greater energy awareness and facilitate curtailment events;
- Shield the contributor from the full brunt of the [system operator] penalties and their related complexities;
- Submit weekly meter data on the contributor's behalf to protect them from meter data penalties resulting from late or incorrect data."

Aggregators also provide notable advantages to utilities who wish to increase their use of demand response. For example, utilities may not have the customer engagement and technological expertise

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[65] https://www.bpa.gov/EE/NewsEvents/presentations/Documents/DER%20Utility%20Brown%20Bag%2020161020%20final.pdf, slide 30

[66] http://rodanenergy.com/the-evolution-of-demand-response-in-ontario/

across diverse industries that an aggregator can provide. It likely does not make sense for ratepayers to pay for utility staff to develop this expertise for the purpose of DR programs alone; where demand response is closely coupled with energy efficiency programs, utilities may already have some of this expertise.

The primary examples of aggregators playing these critical roles are in wholesale markets, although aggregators also work productively with utilities. EnerNOC, for example, provides 186 MW of demand response to the Tennessee Valley Authority from roughly 500 customers and 1,300 facilities.[67] They will also deliver about 4 GW in the PJM capacity (Reliability Pricing Model) construct in 2017–2018.[68] In ISO-NE, 799 MW of demand response is providing capacity in the winter of 2020–2021.[69] Enerwise Global Technologies has collected 416 MW, while EnerNOC has aggregated 184 MW. In Ontario, EnerNOC will provide 139 MW of demand response in the winter of 2017–18 while Enershift Corp. will provide 124 MW.[70]

4.6. Cost and Benefit Analysis

Cost-effectiveness is a critical screen for DR resources: if other resources would be less costly they should be deployed instead. In order to deploy a cost-effectiveness screen, however, a number of items must be established first. These include the form of the cost-effectiveness test (or tests) to be used, the costs to be included, and current estimates of the costs that will be avoided.

For screening tests, options include tests from a societal cost, total resource cost, program administrator cost, participant cost, or rate impact perspective. Each of these tests measures cost-effectiveness from a different perspective, and thus includes different costs and benefits. A societal test, for example, might include avoided environmental externalities from the use of relatively inefficient peaking generation, while not including the transfer of an incentive from the utility to the participant. Meanwhile, the program administrator cost test does not include the customer's cost to implement DR measures. Our Synapse colleagues worked with the Regulatory Assistance Project to develop "A Framework for Evaluating the Cost-Effectiveness of Demand Response" for the National Forum on the National Action Plan on Demand Response: Cost-effectiveness Working Group in 2013.[71] This report identifies the reasons to select each of these tests and example calculations of their application.

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[67] Sarah McAuley, EnerNOC, Personal communication, March 16, 2017.

[68] http://investor.enernoc.com/releasedetail.cfm?ReleaseID=850534

[69] See https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/?key-topic=FCM%20Capacity%20Commitment%20Period%202020-2021

[70] http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2017.xml

[71] http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-02.LBL_.DR-Cost-Effectiveness.11-106A.pdf

Costs to implement DR programs can be divided into enablement or set-up costs and on-going or implementation costs. The NWPCC potential study discussed previously[72] takes a societal perspective. Their enablement costs include technology costs and installation costs, including both customer costs and program incentives. Implementation costs include costs of program administration, DR management systems, and evaluation studies. When evaluating the total costs, the evaluator must determine a reasonable lifetime for measures, so that the up-front costs can be levelized over all years (or alternatively, the implementation costs can be present-valued).

Benefits of DR programs come primarily in the form of costs avoided. These may be energy, capacity, ancillary services or wires (transmission or distribution) costs. There may also be market price effects or avoided environmental impacts. To be accurate, these avoided costs must reflect the particular circumstances, including existing and projected utility portfolios and the local and market costs of supply-side resources. Costs and benefits include avoiding some energy cost, but (in the case of load shifting) purchasing some other energy at a different time. Line losses rise with the square of the power demanded, so marginal losses of energy and capacity are reduced by flattening loads.

Both the costs and benefits of demand response may change substantially over time. If a market moves from surplus into shortage on capacity, for example, the benefits of avoiding capacity costs can increase rapidly (and vice versa). In ISO-NE, for example, capacity costs rose from their administrative floor price of $3.15/kW-month ($37.80/kW-year) for delivery in 2016–17 to $9.55/kW-month ($114.60/kW-year) in 2018–19, then fell to $5.30/kW-month ($63.60/kW-year) for 2020–21 delivery. Costs and benefits should also be considered in total, rather than in isolation. Where a resource may provide a stack of benefits—both winter peaking capacity and balancing to enable renewable energy integration, for example—all benefits relevant to the cost-effectiveness test should be included.

Benefits may not flow to the parties incurring costs: program design or public policy may need to intervene to make a societally cost-effective choice favorable to both utility and participant. Program design should reflect benefits and what is necessary to move a sufficient market to provide the resource necessary, while limiting free-ridership. Changes in the economics of a program should reflect the costs or the benefits sides of a cost-effectiveness calculation. HQD has shown this flexibility by paying $70/kW for demand response through its commercial *GDP Affaires* program.[73] Updating costs and benefits on a regular basis, and in a transparent and well documented fashion, allows stakeholders and regulators to ensure that programs are capturing all of the cost-effective potential. Sudden changes in program design should be avoided, however, as it takes time for DR participants to make changes to their facilities and they may react negatively to continually changing compensation or program design that puts their investments at risk.

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[72] https://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

[73] http://www.hydroquebec.com/business/energy-efficiency/demand-side-management/financial-assistance/

5. Application of Best Practices to Québec

Informed by the best practices detailed above, and our understanding of the HQD system, DR programs and planning to date, we have the following suggestions. Implementation of these suggestions will depend on engagement and actions from both HQD and its regulator. While implementation of any of these suggestions would improve HQD's DR planning and programs, there are synergies between them that would make the combined portfolio of changes more effective.

5.1. Planning

If all cost-effective DR potential is not harnessed, customers will pay more for electricity service from HQD than they otherwise would. HQD does not have an established structure for DR planning that is grounded in achievement of all cost-effective DR potential. As a symptom of this lack of structure, HQD has not conducted a DR potential study since 2012. In addition, that study did not consider the achievable potential or how quickly programs could ramp up to capture the potential. Instead, HQD has taken a piecemeal, "bottom up" approach to DR planning, such that only current or immediately foreseen DR programs are included in the Supply Plan. HQD has made some steps in the appropriate direction by including in the Supply Plan the expected growth in current programs. Where it falls short is in recognizing the impacts of additional programs over the coming decade.

An improved planning approach could take a structure like this:

- Conduct potential studies on a regular basis (e.g. every three years in preparation for the Supply Plan), including assessment of the achievable potential and of avoided costs.
- Determine an appropriate fraction of the cost-effective DR resource to pursue in the long term, informed by the size of the utility's peak demand gap. (Note that the cost-effective and achievable potential may exceed the Distributor's needs.)
- Identify a program portfolio that can cumulatively generate that amount of demand response, favoring programs that can ramp more quickly or whose impacts are more assured.
- Taking into account the pace of program development and roll-out, map out the amount of demand response achievable in each year over the course of the Supply plan, and include that resource as the planned DR resource in the Supply Plan.

Documentation of avoided costs, achievable potential, program implementation plans, and the Supply Plan itself should all be made available to the public, stakeholders, and the Régie de l'énergie on the appropriate and recurring schedule.

Jurisdictions that have adopted explicit expectations that energy efficiency programs will achieve "all reasonably available cost-effective energy efficiency," or similar goals, have generally experienced greater success at meeting power system needs at least cost. Therefore, we suggest that the Régie consider adopting such an explicit formulation for HQD's demand response.

DR planning must be consistent with other aspects of supply planning. In the current Supply Plan, HQD has identified an impact of 189 MW by 2026 from EVs, but has not addressed EV demand response in any way. EVs are eminently controllable loads, and excluding any impact from "smart" charging programs or rate structures into the forecast is a significant oversight. This is a result of the bottom-up modeling approach that HQD has chosen—there are no EV DR savings because there is no current program. This is backwards: HQD should assess the potential and include all cost-effective EV demand response in the Supply Plan, and then commit to developing the tools necessary to achieve that savings over the coming decade.

Stochastic planning for supply might be particularly useful in the Québec context because of the impact of weather variability and the patrimonial supply construct. Different DR strategies might, for example, enable more robust use of the patrimonial supply in the face of year-to-year load variability.

5.2. Avoided Costs

To plan well while considering the cost-effectiveness of each DR program, accurate avoided costs are essential. Québec has a particularly complicated structure in which to calculate avoided costs, due to the dynamics between the patrimonial supply structure, other long-term contracts, market interactions with neighboring states and provinces, and possible additional U.S. interties.

The patrimonial supply structure places a premium on a load duration curve as similar as possible to the patrimonial curve, with predictable deviations allowing the cost-effective purchase of additional supply. Designing demand response and other load control as tools to make the deviations from the patrimonial "bâtonnets" more predictable, and quantifying the benefits, will be a fascinating challenge. As load rises, the relationship between load and the patrimonial supply structure also changes, so avoided costs must be re-evaluated on a regular basis as part of the planning process. Avoided costs will also differ by the shape and duration of each particular DR or load shaping program—the cost savings from load changes in the top 20 hours, top 300 hours, and top 2000 hours of the year are quite different. HQD's approach to calculating avoided costs should be revised (and updated regularly) to take into account the differences in avoided costs in relation to HQD's peak hours and to allow customized avoided costs to be calculated for different kinds of DR interventions.

In order to best match DR potential with avoided costs, HQD may require more extensive data and models regarding the load shapes of different classes or sectors of customers than it currently possesses.[74]

[74] In response to RNCREQ's DDR 9.1.3, 9.1.4, and 9.5, HQD says that it does not model the contributions of some sectors to winter peak, possess hourly consumption data, or model winter peak stochastically. Data from AMI deployment should make it possible to do so.

5.3. Peak-Time Rate or Rebate Programs

The Distributor offers several programs today that are very similar in nature to critical peak price or peak time rebate programs. However, it should consider expanding these options to more customers and classes to both capture cost-effective DR capacity and empower customers to take greater control of their electricity usage and costs.

Commercial and industrial interruptible load programs, which compensate participants based on their reduction from an established baseline over a set period of time at the utility's request, are functionally very similar to peak time rebate programs. In HQD's case, these are reflected in the interruptible forms of Rates M, G-9, and L, as well as the *GDP Affaires* program. These programs are more certain—unlike a PTR program, participants generally *must* curtail load, rather than only having the option. They also require a certain size of resource. Aggregation can address both of these concerns, from a customer perspective.

For residential customers, Rate DT has the form of a critical peak price rate, with some limitations and differences. First, it is triggered by temperature, rather than a utility call. As a result, it may trigger on a weekend, or overnight, when HQD would not have chosen to call a DR event. Second, it is available only to customers with the heating hardware necessary to switch to another fuel. HQD is piloting the use of an interruption signal, rather than temperature, and hardware without automatic fuel switching (behavioral savings), and these changes would shift the program closer to critical peak pricing.

HQD piloted TOU with critical peak pricing ("Réso+") during the winters of 2008/2009 and 2009/2010. This program demonstrated average savings of about 6 percent on peak. If a 6 percent effect were to be scaled to HQD's full residential and agricultural class, it could reduce winter peak by more than 1 GW.[75]

HQD's marginal energy and capacity prices are nearly flat over all hours except around winter peaks. As a result, a daily TOU rate is not justified, based on cost of service.[76] However, a program that targets winter peak in particular, when the marginal costs are significantly higher, would be economically efficient (assigning costs to those who are causing them). It would likely incent consumer behavior that would lower the overall cost of service. As suggested earlier, a more granular approach to calculating avoided costs based on time of use (in relation to the system peak) would greatly facilitate the quantification of DR benefits.

HQD's current rate structure for medium to large commercial and industrial customers (such as Rates M and L) have a demand charge component, reflecting some peak costs. However, these demand charges do not depend on coincidence with system peak. Peak-coincident demand drives capacity costs, but is not reflected in the structure of these rates. A customer whose industrial process results in a peak at some time other than the system peak has no incentive to shift their load away from the winter peak,

[75] If at least 28% of the "other" end uses on winter peak are from residential and agricultural customers.

[76] R-3972-2016, HQD-2, document 1 (report from Christensen Associates), page 46.

unless they have had the foresight, are eligible, and are willing to take the risk of the Distributor's interruptible load programs. HQD is missing an opportunity to better align rates with cost causation and to provide this economic incentive to these customers, by integrating a coincident peak component into these rates or making a peak time rebate structure the default.

A peak time rebate program available to all customers (or even made the default for all customers, since their bills can only go down for participating), could be well aligned with HQD's marginal cost structure and meet with customer acceptance. Such a program, while it may be implemented through rates, is in effect a DR program with a very flexible opt-in structure. It would allow customers who are willing and able to take actions to help the system to exercise control over their electric bills. HQD's 2012 DR potential study identifies a series of behavior change measures in the residential sector that, if they were fully additive, would total 1,600 MW. Even just convincing customers to delay use of the dryer could reduce the peak by more than 500 MW. Such a program would also serve to reduce, perhaps to a *de minimis* level, the winter peak impacts of EV charging.

To identify and harness the full cost-effective residential flexible capacity resource, HQD should build on its 2008–2010 TOU and CPP pilot by testing new PTR or CPP programs, grounded in updated and more granular avoided costs. If they prove promising and cost-effective, HQD should then introduce them as general opt-in or opt-out options to all customers.

5.4. Pilots to Programs

HQD is actively pursuing new DR interventions, particularly in water and space heating, in ways that reflect the specific needs and markets in Québec, and it is to be applauded for this. This is necessary groundwork for the achievement of the cost-effective potential just discussed. As new programs are developed and are able to move from pilot to implementation, it is important that HQD move with all due haste to launch programs and capture the cost-effective potential.

While we appreciate that HQD has great respect for stakeholders concerned with its proposed water heater DR program, we encourage HQD and the Régie to move this program into implementation as quickly as possible. HydroQuébec has a history of intervening in the water heater market, through the development of the three-element water heater, although adoption of that water heater has not reached its potential.[77] Water heaters provide a large resource, particularly in the Québec context. As a resource, they can be applied not just to winter peak but also to localized distribution constraints, daily load flattening, frequency regulation, or wind energy integration. Other utilities interrupt water heaters more than 20 times per year,[78] and use them to target specific cost drivers; HQD can do the same. If

[77] HQD's reply to RNCREQ's DDR 5.2.1 indicates that three-element heaters have only a marginal impact on winter peak.

[78] GRE uses its peak shaving water heaters 40 to 60 times per year, for 5 to 7 hours at a stretch. Thermal storage water heaters are curtailed for 16 hours every day. (Gary Connett, GRE, personal communication, March 23, 2017)

water heater control could achieve its full potential (identified by HQD as 450 MW[79]) over the course of the coming decade, that one program would meet more than one-quarter of the additional peak power identified in the Supply Plan.

HQD should consider enlisting the assistance, through shared business opportunities, of third-party DR experts and aggregators. While HQD has deep knowledge of the unique factors that shape its peaks and the Québec markets, insights from third parties could bring new vision and technologies. Québec is a large enough market to catch the attention of technology developers who may be able to bring entrepreneurial spirit to the benefit of the system.

5.5. Standards

HQD has a unique ability and role in the market for electric appliances and control systems in Québec . If it were to be consistent and clear that it would develop and harness systems that use standardized systems for integration and communication, such as USNAP/CTA-2045 and OpenADR, it could move the market to adopt these standards throughout the province. At the same time, using these standards would allow HQD and its customers to take advantage of products and technologies developed for other markets. Actions in this area could include working with the manufacturers of three-element water heaters to incorporate USNAP, and integrating OpenADR expectations into energy efficiency program offerings around building or facility energy management systems.

5.6. Quantify Impacts

To adequately plan for utilizing DR measures, their impacts must be quantified. The Supply Plan indicates that appeals to the public are a means of last resort and their contribution has not been quantified. However, if HQD were to measure the impact of such appeals, it would at least have some indication of their effectiveness. In particular, assessment of the impact of public appeals on a regular basis would allow HQD to know whether the effect of such appeals is increasing or decreasing. If HQD were to implement a widely applied and peak-focused program through rates (as recommended below), quantification of appeals prior to the implementation of that program would allow comparison of behavioral and financial programs. This would inform a more refined cost-effectiveness determination. A personalized behavioral DR program (with appeals by text, email, or automated phone call) would both enable and require the separation of a control group to measure program impacts so they could be included in planning. At minimum, as HQD expands its DR offerings, it should employ best practices in evaluation, measurement, and verification of programmatic impacts.

[79] HQD-1, Document 1, Page 21

5.7. Customer Engagement with Energy Efficiency

HQD operates a significant portfolio of energy efficiency programs; governmental programs (such as *Renoclimat*) can also produce significant energy savings. These programs already engage HQD customers on energy issues, and should be encouraged to further integrate DR opportunities. As of February 15, 2017, HQD has improved its programs in this respect by including power management for winter peak as an eligible measure in its industrial retrofit program.[80] This has the potential to contribute to the increase in DR savings from industrial customers that is projected in the Supply Plan, and may allow HQD to increase its projections above those levels as customer response is gauged. HQD should build on this example and integrate demand response into its other energy efficiency offerings where cost-effective opportunities exist.[81]

5.8. Flexible and Inclusive Program Design

In contrast to supply-side resources, harnessing demand-side resources requires the active participation and engagement of a broad range of customers. These customers operate diverse facilities, and have unique financial situations. Flexible program design that meets these customers where they are and offers them a way to participate is therefore essential to fully capture the potential. HQD has experienced this recently, with changes in the interruptible load program driving increased participation and giving HQD confidence that this program can grow from 850 MW to 1,000 MW. The new *GDP Affaires* commercial interruptible load program provides options to an underserved market, and has seen faster success than projected. We encourage HQD to continue to diversify their offerings or make them more flexible, especially for commercial and industrial customers, to encourage greater participation on terms that make sense for both participant and Distributor.

The *GDP Affaires* program includes two features that we encourage HQD to consider as it develops other programs: a minimum or capacity payment, and the welcoming of aggregators. By offering a capacity payment regardless of whether a DR event is called, the program allows the customer to be assured of a minimal payback on their costs to join the program and any associated changes in their infrastructure or controls. Aggregators can be a key partner to attract and include smaller variable loads (e.g. smaller than the 200 kW minimum for direct participation in the *GDP Affaires* program). Aggregators can also insulate their participants from the vagaries of program design and introduce flexibility and diversity in customer economics that might be difficult to implement by tariff.

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[80] http://www.hydroquebec.com/business/energy-efficiency/programs/industrial-systems-program/retrofit/financial-assistance/

[81] DR and energy efficiency planning might benefit from being done jointly as well.

ABOUT THE AUTHORS

Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30 includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors. They have held positions as regulators, economists, and utility commission and ISO staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions throughout the United States and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for international clients has included projects for the United Nations Framework Convention on Climate Change, the Global Environment Facility, and the International Joint Commission, among others.

Dr. Asa S. Hopkins

Asa Hopkins, PhD, is an expert in the development and analysis of public policy and regulation regarding energy and greenhouse gas emissions, including cost-benefit analysis, stakeholder engagement, state energy planning, and utility planning. He has provided analysis and testimony in both legislative and regulatory contexts, including state utility regulation and state and federal rulemaking.

As the Director of Energy Policy and Planning at the Vermont Department of Public Service, Dr. Hopkins was responsible for development and analysis of state policy regarding renewable energy, ratepayer-funded energy efficiency, energy-related economic development, and innovative utility rates and programs. He was responsible for developing the state's Comprehensive Energy Plan, reviewing utility integrated resource plans, and directing the actions of the Planning and Energy Resources Division. He also served on the Board of Directors of the National Association of State Energy Officials. During his tenure, Vermont rose in the rankings on national clean energy state scorecards.

Prior to 2011, Dr. Hopkins was an AAAS Science and Technology Policy Fellow in the Office of the Under Secretary for Science at the U.S. Department of Energy. In that role, he managed stakeholder engagement for and the overall project flow of DOE's first Quadrennial Technology Review. Dr. Hopkins came to DOE from Lawrence Berkeley National Laboratory, where he worked on economic and market analysis of appliance energy efficiency standards.

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Melissa Whited specializes in issues related to utility regulation, distributed energy resources, and the water-energy nexus. Much of her work focuses on alternative regulatory models to respond to fundamental changes in the electricity landscape spurred by declining demand, new technologies, environmental policies, and the integration of large amounts of renewable energy. Ms. Whited consults on the tools to effectively address this shift, including utility performance incentives, revenue decoupling mechanisms for energy efficiency, innovative demand response programs, and alternative ratemaking.

Recently, Ms. Whited was integrally involved in the development of a benefit-cost analysis framework for distributed energy resources within the context of New York's "Reforming the Energy Vision" proceeding. Her other recent work includes consulting on decoupling cases in Maine, Hawaii, and Nevada; conducting a comparative analysis of demand response programs across the United States; analyzing experiences with performance incentives for utilities; and evaluating proposals for time-varying rates in the Northeast.

Ms. Whited's expertise also encompasses water resource issues. In 2013, Ms. Whited led a study examining the water resource impacts and vulnerabilities of the U.S. power sector. Prior to rejoining Synapse as an associate in 2012, she published in the Journal of Regional Analysis and Policy regarding the economic impacts of irrigation water transfers, and analyzed water resource efficiency options for Wisconsin. Ms. Whited holds two master's degrees from the University of Wisconsin: an MA in agricultural and applied economics, and an MS in environment and resources.

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