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Comments on the 2017 General Rate Application of Newfoundland Labrador Hydro

submitted to the
NL Public Utilities Board

on behalf of

the Labrador Interconnected Group

by

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1. INTRODUCTION AND SUMMARY

I have been asked by the Labrador Interconnected Group to review the aspects of Hydro's 2017 General Rate Application (GRA). This report will address three issues:

- The proposed rate increased for the Labrador Interconnected region, and the causes for the proposed increases;
- Issues concerning transmission expansion in Labrador West, and
- The new Newfoundland and Labrador System Operator (NLSO).

The report's conclusions are summarized in the following sections.

1.1. Labrador Interconnected rates

The application proposes to increase rates by 4.4% in 2018 TY and by 12.96% in 2019 TY, relative to 2015 TY. These increases are driven by capital costs. Relative to 2015 TY, capital costs will increase by over 40% by 2019 TY, and rate base by 49.1%. Non-capital costs in fact decline.

The largest component in the capital cost increase is the Muskrat Falls-Happy Valley Interconnection project, with a cost of about $20 million. The need for this project is not apparent from the load forecasts presented in the GRA. However, the planning report presented in the capital budget filing indicates a dramatic increase in the load forecast over the last year, due in large part to load requests for data centers, which have created "a very high and immediate demand". As discussed below, further information is required in order to properly assess the likelihood that these loads will in fact materialize.

1.2. Labrador West transmission

The most recent load forecasts show an increase of 50 MW in Labrador West by 2020 due to data centers. An increase of just 19 MW above current levels will require expansion of the transmission capacity, which may require development of the Labrador West Transmission Line (LWTL), on which work was suspended in 2014. The capital cost of the Lab West Transmission

Line is estimated at **more than $330 million**, which would result in a revenue requirement impact of about $24.7 million per year, almost doubling the Labrador Interconnected 2019 revenue requirement. In the last GRA, debate about the Labrador West Transmission Line was deemed premature.

Media reports reveal that data centers are being established in Labrador for bitcoin mining, one of which has received $1 million of federal and provincial support. It is unclear, however, whether the existing fibre optic network could support the data center expansion described in the load forecasts.

Given the magnitude of the rate impacts should construction of the LWTL be triggered by these loads, **there is an urgent need for a detailed report to be presented to the Board on prospective data center loads in Labrador, so that the Board can provide guidance to Hydro, if appropriate, with respect to the signing of additional data center power contracts or service agreements.** As elaborated upon below, requiring that new data centers accept peak load curtailment provisions as a condition of service could be an element of such guidance. Other forms of load growth mitigation should also be considered, including offering curtailment (interruptible) contracts to existing large users in Labrador.

1.3. Labrador Industrial Transmission Rate

1.3.1. Network addition policy

Hydro’s current network addition policy is inadequate to address situations such as the one described above, as it classifies as common all assets that serve more than a single customer. As noted in our testimony in the hearing on the 2013 Amended GRA, the existing LITR should be modified to include a network addition policy that reflects FERC policy, which is designed to protect existing transmission customers from excess costs resulting from network upgrades that are needed in order to provide service to new users. If the expected new data centers in Labrador are not classified as industrial users and so do not take service under the LITR, it is important that a similar policy be adopted for general service customers as well.

1.3.2. Proposed rate design

Hydro is proposing a modification to the LITR rate design. Hydro claims that it will have some seasonal benefits, though in fact the proposed rate provides equal incentive to reduce demand in the summer as in the winter. As the transmission system constraints occur in the winter, this structure provides little incentive to resolve them. Hydro has indicated that it does not rule out the use of seasonal pricing as a vehicle for rate design in the future. We encourage it to continue to explore these options.

1.4. Newfoundland and Labrador System Operator

Hydro proposes the creation of a Newfoundland and Labrador System Operator, a reorganization which appears already to be partially in effect. This step in fact implies significant modifications in the operation of the power system in Newfoundland and Labrador, including the operation of all its transmission assets, including those owned by the Churchill Falls (Labrador) Corporation.

The transition to the NLSO is unlikely to be a simple path. Even in the absence of the uncertainties with respect to Hydro-Québec, the transition from a vertically integrated utility to a quasi-independent system operator will inevitably be far more complicated than one would surmise from reading these few pages of evidence.

It is clear that, before this initiative is completed, the Board will be called upon to approve a number of complex documents, including an open access transmission tariff and codes of conduct. The sheer scale of these undertakings could overwhelm the available resources on the part of the utility, the regulator and the interested parties.

The situation is further complicated by the complex and litigious relationship between Nalcor/NLH and Hydro-Québec. It would be surprising if these issues were to suddenly be resolved.

Hydro has not explained its choice of the System Operator model, as opposed to the much simpler model of a functionally separate transmission operator within an integrated utility. It would be helpful if Hydro were to share with the Board and the interested parties a roadmap encompassing all the structural changes it intends to undertake, to allow reasoned consideration of the best path forward.

2. LABRADOR INTERCONNECTED RATES

2.1. Drivers for the proposed rate increase

In its GRA, NLH requests a rate increase for Labrador Interconnected of 4.4% for 2018 and of an additional 8.2% for 2019 (both increases effective on January 1),[1] which implies a rate increase for 2019 TY of 12.96%, relative to 2015 TY.

	Current	Proposed Jan. 1, 2018	Proposed Jan. 1, 2019
Domestic			
fixed charge ($/month)	7.09	7.41	8.03
energy (cents/kWh)	3.255	3.402	3.688
General service (over 1000 kVA)			
Demand ($/kW)	1.71	1.79	1.91
Energy (cents/kWh)	1.725	1.799	1.948

These increases are primarily due to an increase in the Labrador Interconnected System revenue requirement, which (prior to allocation of the rural deficit), is estimated to grow from $22.8 million in 2015 TY to $24.5 million in 2018 TY a 7.5% increase) and to $26.5 million in 2019 TY (an additional 8.2% increase).[2] Thus, the revenue requirement in 2019 TY will be some 18.7% greater than that in 2015 TY.

[1] GRA, Vol. 1, page 5.33. Street and Area Lighting accounts are excluded from these increases.

[2] Ibid. Detailed breakdown found at LAB-NLH-014, Attachment 1 (rev. 1).

In order to recover this revenue requirement, customer billings are expected to increase by 6.2% in 2018 TY and another 11.8% in 2019 TY, to recover an additional $1.3 million and $2.4 million, respectively.[3]

These revenue requirement increases are due almost exclusively to capital costs, broken down as follows:[4]

	2015 TY	2018 TY	2019 TY
Depreciation, CIAC, and Other	3.5	4.7	5.8
Return on Rate Base	6.1	7	7.8
Total Capital Costs	9.6	11.7	13.6
increase from previous COSS		21.9%	16.2%
increase from 2015TY		21.9%	41.7%

Thus, 2019 TY capital costs will thus be 41.7% higher than the capital costs recognized in 2015 TY. For 2019, these capital cost increases will result in rate increases of about 1.8 cents/kWh for Labrador residential rates, and of 1.4 cents/kWh for general service rates.[5]

The non-capital line items in fact decline from their 2015 levels:[6]

	2015 TY	2018 TY	2019 TY
Fuels	0.3	0.3	0.3
Power Purchases	1.9	1.4	1.4
Operating Costs	11.4	11.3	11.5
Other Revenue	-0.3	-0.3	-0.3
Total Non-Capital Costs	13.3	12.7	12.9
increase from previous COSS		-4.5%	1.6%
increase from 2015TY		-4.5%	-3.0%

3 GRA, Vol. 1, Table 5-1, page 5.14.

4 From LAB-NLH-010, Table 1.

5 LAB-NLH-053, page 1 of 1.

6 Ibid.

The revenue requirement increase is thus almost exclusively due to increases in the rate base, which is expected to grow by 32.3% in 2018 TY, and another 12.7% in 2019 TY, for a combined increase of almost 50% compared to 2015 TY.[7]

	2015 TY	2018 TY	2019 TY
Average Rate Base	92.5	122.4	137.9
increase from previous COSS		32.3%	12.7%
increase from 2015TY		32.3%	49.1%

The most significant increase in the rate base is due to 2018 forecast capital expenditures, in excess of $32 million:[8]

$000s	2018	2019	2020	2021	2022
Forecast capital expenditures	32,179	9,006	8,123	8,298	6,262

The largest component of this 2018 capital expenditure is the "Muskrat Falls to Happy Valley Interconnection" project, with a revised budget of $19,978,500.[9] This project forms part of Hydro's 2018 Capital Budget Application, currently under consideration by the Board.

2.2. The Muskrat Falls to Happy Valley Interconnection project

The Muskrat Falls to Happy Valley Interconnection project alone has a rate impact of 3.1% in 2018TY and of 7.6% in 2019TY.[10]

Thee estimated project cost has declined since the filing of the original GRA, from $23.5 million to $20.0 million. Commissioning of the transmission interconnection is anticipated for December

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[7] LAB-NLH-012. Table 1.

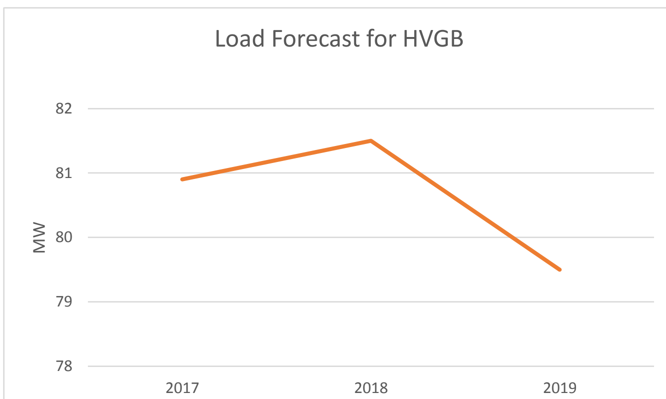
[8] LAB-NLH-031, Attachment 1, page 1 of 1.

[9] LAB-NLH-060. In LAB-NLH-033, Attachment 1, page 1 of 1, a cost of $23,513,900 is attributed to this project.

[10] CA-NLH-166, Table 1.

2018, and of the 50 MVA transformer for December 2019.[11] Should the capital cost decline farther, or should the commissioning dates be delayed, the rate increases for 2018TY and 2019TY for which approval is sought in the present proceeding would no longer be justified, at least in part. **To the best of our knowledge, there is no procedure in place to ensure that rates based on a forward test year do not over-collect, based on actual costs during the rate year.**

It is difficult to discern the need for this project based on information presented in the GRA. In response to an RFI, Hydro presented the following load forecast for Happy Valley Goose Bay (hereinafter "HVGB"), explaining that it includes requirements for Northwest River, Sheshatshui and Mud Lake as well:[12]

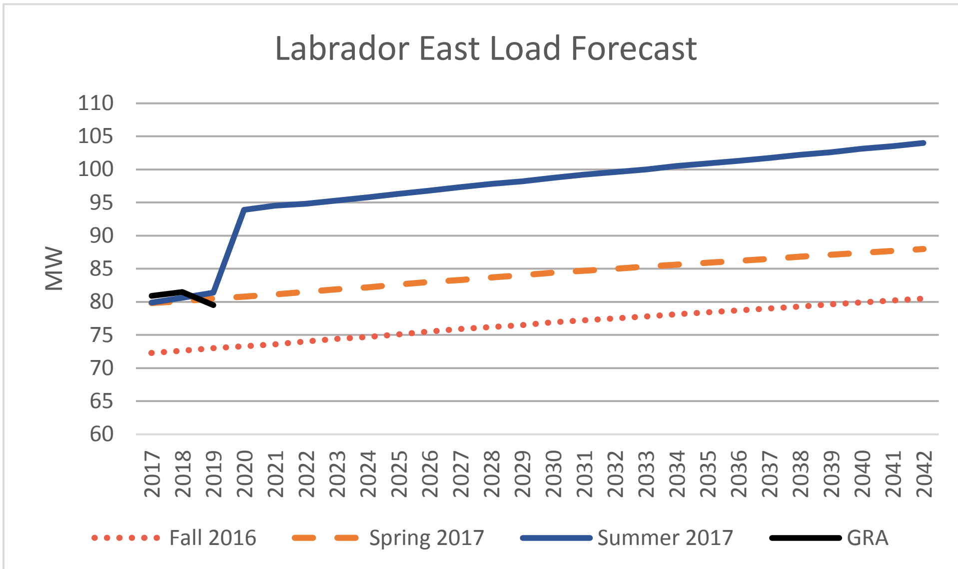


However, the load forecast presented in the Eastern Labrador Transmission System – Planning Report, dated August 21, 2017, which is included in the capital application, tells a different story, summarized in the following graph:[13]

[11] NLH, 2018 Capital Budget, Vol. 2 (rev. 1), Tab 13 (Muskrat Falls to Happy Valley Interconnection), page 9 (p. 329 of pdf).

[12] LAB-NLH-027

[13] NLH, 2018 Capital Budget, Vol. 2, rev. 1, Tab 13 (Muskrat Falls to Happy Valley Interconnection), Appendix A, page 6 (p. 340 of pdf).



In this graph, the black line represents the load forecast from the GRA, as shown in the previous graph. The dotted red line shows the 25-year load forecast from the fall of 2016, which shows loads of just 72 MW in 2017, growing to about 80 MW by 2042. The dashed orange line shows the update from six months later (spring of 2017), showing this 80-MW level already met in 2017 (consistent with the GRA forecast), and growing to 88 MW by 2042. And the blue line, from the summer of 2017 (just a few months later), shows loads jumping to almost 95 MW as early as 2020, and then continuing to grow to almost 105 MW by 2042.

Thus, significant changes appear to be underway in Labrador that are not fully described in the Application. The Eastern Labrador Transmission Planning Report provides a partial explanation:[14]

> Within the last year there has been a 29% increase in the 2042 forecast (from Fall 2016 forecast to the revised forecast in the Summer 2017).
>
> The load increases over the past year reflect data center load requests received prior to July 7, 2017, and the Department of National Defence conversion to all-electric boilers at Canadian Forces Base Goose Bay. <u>The 7.6 MW increase in the 2017 forecast is a direct result of service applications for new data centers</u>, while an increase of approximately 12.5

[14] Ibid., Tab 13 (Muskrat Falls to Happy Valley Interconnection), Appendix A, page 5 (p. 339 of pdf).

> MW in 2020 is directly attributed to the Department of National Defense (DND) conversion to all-electric boilers.
>
> As is seen in the table, these potential loads have created a very high and immediate demand, which has necessitated the requirement of increasing the capacity of the existing transmission system.

These new data center loads were mentioned, briefly, in the Application.[15] More information is found in the responses to RFIs:

> New data center loads refer to recently connected general service customers currently being served by Hydro on the Labrador Interconnected System and whose primary business involves data processing with computer equipment. The energy consumption of data center customers is primarily from the computer equipment but also includes the lighting, heating, and ventilation loads for the building in which the business operates. In the load forecast for the Labrador Interconnected System, the new data center loads are forecasted to increase across the 2017 through 2019 period resulting in increased demand and energy requirements to be served by Hydro.
>
> Hydro continues to receive requests for service for new data center loads beyond those reflected in the Test Years which will impact future load requirements for the Labrador Interconnected System. These new loads and the resulting impacts for the Labrador Interconnected System are currently being studied by Hydro.[16] (underlining added)

And:

> With respect to any material changes to Hydro's forecast electricity requirements for the Labrador Interconnected System as provided in Schedule 3-II, Hydro has recently received numerous service applications by businesses planning to set up and operate data processing centers in both Labrador East and Labrador West. The load requirements as indicated in the service applications provided by the data centers reflect material changes to the Hydro Rural Interconnected load forecast for Labrador as increased load requirements impact the timing and scale of capital investments required to serve the Labrador Interconnected System. While Hydro has submitted a capital plan in its 2018 Capital Budget Application to address higher load requirements in Labrador East and is currently assessing the impact of higher load requirements in Labrador West, the costs of which are reflected in rates that will result from this 2017 General Rate Application (GRA), other capital investments that may result from the above mentioned service applications will not be required during the time that rates resulting from this GRA will be in effect.[17] (underlining added)

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[15] Pages 3.17 and 3.18.

[16] PUB-NLH-035, page 1 of 1.

[17] IC-NLH-078, page 2 of 2.

More specifically:

> As of 13 July 2017, Hydro has received six service request applications from four individual companies with a total load requirement in Labrador West of approximately 50 MW.[18]

As noted above, these data centers, together with the DND conversion to all-electric boilers, are largely responsible for the Labrador Interconnected rate increases presented in this GRA, due to the resulting need for the Muskrat Falls to Happy Valley Interconnection Project.

The Application provides little insight into the extent to which Hydro and/or the provincial government has actively sought these data centers, or whether special terms are being offered to them to attract them to Labrador. Given the rate impacts that are already flowing from these new installations due to the transmission additions required to serve them in Labrador East, as well as the much greater rate impacts that could result from new loads in Labrador West, it is important to ensure that load-building activities are in the public interest. It is also unclear from the current filing whether Hydro has discretion in accepting these service requests, or not, and whether it can impose conditions.

We will return to this issue in the next section.

3. LABRADOR-WEST TRANSMISSION

3.1. Load growth and the Labrador West Transmission Line

As noted above, Hydro has forecast an additional 50 MW of data center loads in Labrador West by 2020.[19] In another response, it acknowledged that new data center loads may require transmission upgrades in Labrador West as well as in Labrador East.[20]

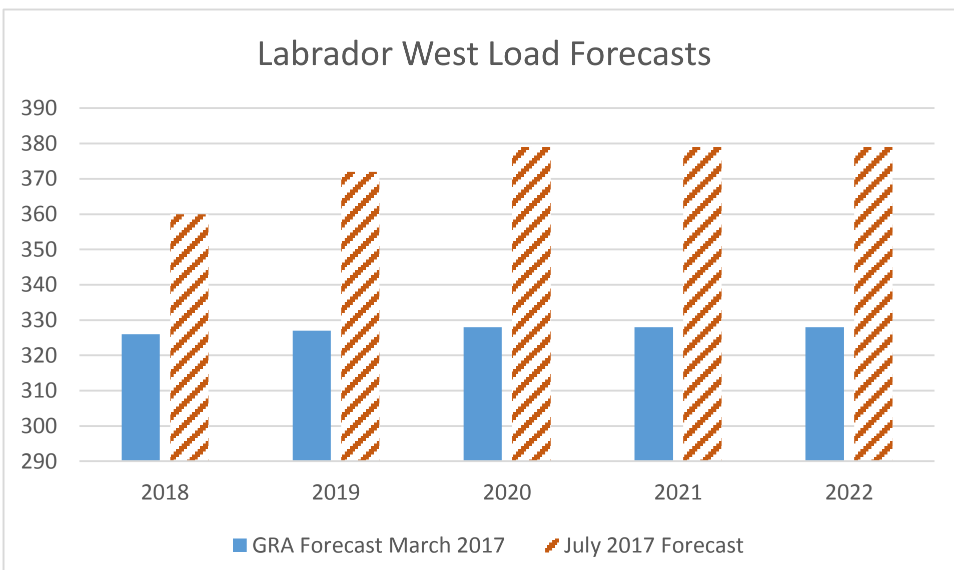
[18] IOC-NLH-033, page 2 of 3.

[19] IOC-NLH-033, page 2 of 3.

[20] IC-NLH-078, page 2 of 2.

According to a revised RFI response, load growth of just 19 MW in western Labrador would require expansion of the transmission system.[21] As this calculation references Schedule 3-II, which shows only 11 MW of growth in Hydro Rural Interconnected load from 2016 through 2019, it would appear that this 50 MW of new data center load is not included in these figures. There is thus a real concern that Hydro may be making commitments to data centers that would make expansion of the Labrador West transmission system unavoidable and urgent. The Labrador West Transmission Line (hereinafter "LWTL"), which was suspended in 2014 when the Kami mine project was suspended, is a major project which would have significant rate impacts in Labrador.

In a response to IOC, Hydro details the changes in the Labrador West load forecast since the March 2017 forecast on which the GRA was based. The figures are summarized in the following graph[22]:



[21] LAB-NLH-028, rev. 1, page 2 of 4.

[22] IOC-NLH-033, Table 1, page 3 of 3.

More specifically, the response indicates that forecast Lab West loads for 2018 TY have increased by 34 MW, those for 2019 TY by 45 MW, and those for 2020 TY by 51 MW, due to new data center loads. It would thus appear that the 19 MW of headroom referred to earlier has already been exceeded.

Hydro indicates that it is currently undertaking a transmission planning study for western Labrador,[23] which will form part of Hydro's 2019 capital budget application, which would normally be submitted in the summer of 2018.[24] However, if the investment is required earlier, Hydro could file a supplemental capital application requesting approval thereof.[25]

The capital cost of the Lab West Transmission Line, on which work was suspended in 2014[26], is estimated at **more than $330 million**, which would result in a revenue requirement impact of about $24.7 million per year,[27] almost doubling the Labrador Interconnected 2019 revenue requirement of $26.5 million, cited earlier. Hydro estimates that this would increase residential rates by about 1.8 cents/kWh, and general service rates by 1.4 cents/kWh,[28] though it did not provide its detailed calculations.

In the last GRA, debate about the Labrador West Transmission Line was deemed premature, as it was believed that it would only be necessary if Alderon's Kami Mine Project were to be revived, which seemed unlikely at the time. [29] No mention was made of other types of loads, such as data centers, that could have the same effect.

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[23] IOC-NLH-021, page 1 of 2.

[24] LAB-NLH-052, page 1 of 2.

[25] Ibid.

[26] NLH, 2013 Amended GRA, IN-NLH-247, Att. 1, page 1 of 2, Note 2.

[27] IOC-NLH-024, page 1 of 2. The $330 million capital cost estimate is from 2014, and Hydro indicates that "An updated cost estimate would be anticipated to be higher than the 2014 capital cost estimate" (Note 2).

[28] LAB-NLH-053, page 1 of 1.

[29] NL Hydro 2013 Amended GRA, transcript of September 11, 2015, pages 103 and 104.

3.2. Data centers

Apart from the references mentioned above, Hydro has not provided any specific information regarding the current and expected power usage from data centers in Labrador. However, media reports published over the last year make clear that this industry's interest in Labrador is well known.

Two Labrador data centers have been mentioned in recent media reports, Great North Data ("GND"), and North 53 Degrees. While we have been unable to locate any information regarding the latter company, several documents referencing GND are provided in Appendix A.

GND is a company based in St. John's which "has secured contracts providing us with green hydroelectricity at one of the lowest prices globally"[30]. According to a July 2016 report in CBC[31], GND's main line of business is "mining" bitcoins, a process that requires a great deal of computing. It also quotes GND officials as stating that Labrador West is an ideal location since, " 'just like iron ore mining, energy cost is crucial in breaking even and profiting' ". They added that, "Lab West climate is perfect for data centres. You couldn't have picked a spot that's colder that has access to this kind of electricity."

The company has obtained almost $1 million in federal and provincial grants to support its expansion:

> **Great North Data** is using a $500,000 repayable investment from ACOA's Business Development Program and $420,000 from the provincial department of Business, Tourism, Culture and Rural Development (BTCRD) to undertake the expansion of its existing data

[30] GND website, http://www.greatnorthdata.com/. See Appendix A.

[31] Jacob Barker, CBC News :"'It's the new emerging thing': Mining for data in western Labrador", July 26, 2016 (http://www.cbc.ca/news/canada/newfoundland-labrador/data-storage-bitcoins-western-labrador-1.3694238), reproduced in Appendix A. The report refers to an installation on Avalon Drive in HVGB, but this appears to be an error. There is an Avalon Drive in Labrador City, but not in HVGB, and the remainder of the article discusses Labrador West.

> centre. Specifically, the project will enable the applicant to increase its capacity through the purchase of power transformers, server racks and a HVAC system.[32]

The CBC article quotes the MHA for Labrador West Graham Letto as saying, "We're open for business, for that type of business, and we see this industry as a major part of a diversification plan. It doesn't create a whole lot of jobs but it generates jobs and every job today is important."[33]

Another official expressed concern about the immense amount of power needed, saying that the town had been approached by a data centre company out of China.

An industry consultant is quoted as saying that the power requirements would not provide a great deal of strain on the power system:

> Dave Pearson is a researcher at International Data Corporation and specializes in enterprise storage and networking in Canada. He said though the power draw is heavy, it isn't crippling.
>
> "When you're looking at what's going on in Labrador for example, <u>those kinds of implementations will not provide a great deal of strain on the local grid and certainly not on a province wide or country wide scale</u>," he said.[34] (underlining added)

There is no indication that Mr. Pearson had consulted with Hydro before making this assertion.

The GND officials added:

> "No-one's ever built a blockchain data centre in Canada this large before and to a large extent, we're kind of creating a plan as we go," Goodwin said, blockchain referring to the dedicated bitcoin equipment.
>
> GND said better infrastructure would be needed if bigger companies like Facebook or Amazon were to take interest.
>
> "Unfortunately there's only one trunk line running into Lab West right now," Goodwin said.

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[32] https://www.canada.ca/en/atlantic-canada-opportunities/news/2016/08/support-announced-for-projects-in-labrador-west.html, reproduced in Appendix A.

[33] Jacob Barker, *op. cit.,* page 2.

[34] Ibid.

> "We already have competition following us here but if they put the investment in the fibreops network, there will be more."

There are many unanswered questions concerning the forecast data center loads for Labrador. It is not clear how much of the forecast loads consist of:

- loads already in service;
- signed contracts for new loads;
- applications for service agreements which are not binding on the applicant; and
- forecasts of future service agreement applications.

In order to estimate the amount of new loads that are likely to occur, it would also be important to understand the extent to which the region's fibre optic infrastructure – both the internet trunk lines arriving in Labrador and the fibre optic cables within the region – are adequate to support these developments.

It would also be important to understand to what extent load curtailment is a possibility in this industry. For online server farms, this would clearly not be an option, but given lack of strong and redundant internet connections, it would appear unlikely this type of business would be attracted in Labrador. For bitcoin mining and other blockchain computations, however, it may well be that reducing activity during system peak hours would not create significant difficulties. If so, making peak curtailment a condition for new data center service agreements could provide a solution to meeting the capacity constraints created by this new industry.

Data centers are clearly attracted by the low power costs in Labrador. However, it would be problematic if their arrival were to trigger investments that significantly raised power costs for existing users — which would certainly be the case, if they were to make necessary construction of the LWTL.

Given the magnitude of the rate impacts should construction of the LWTL be triggered by these loads, **there is an urgent need for a detailed report to be presented to the Board on prospective data center loads in Labrador, so that the Board can provide guidance to Hydro, if appropriate, with respect to the signing of additional data center power contracts**

or service agreements. As elaborated upon below, requiring that new data centers accept peak load curtailment provisions as a condition of service could be an element of such guidance.

3.3. Load growth mitigation

There are many tools at the disposition of a utility to mitigate forecast peak load growth. Traditional Conservation and Demand Management (CDM) is of course one, insofar as reducing energy consumption tends to reduce peak demand as well. However, as capacity growth has overtaken energy growth as the dominant planning issue for many utilities, a great deal of attention has been paid to ways to reduce peak demand.

The most commonly used approach consists of interruptible contracts for industrial demand. Currently, an industry's Power on Order is firm, and any power it should require above that level is interruptible. The Island Industrial Customer contracts currently include a provision for interruptible demand, over and above the Power on Order, with the following standard definition:

> "Interruptible Demand" means, that part of a Customer's Demand which exceeds its Power on Order, which may be interrupted, in whole or in part, at the discretion of Hydro and which is supplied to the Customer in accordance with Clause …"[35]

This is very different from the interruptible contracts offered to industrials in many other jurisdictions, which remunerate them for reducing demand during system peak. In Quebec, Hydro-Québec Distribution has access to 1000 MW of interruptible power.[36]

Clearly, an industrial customer will only subscribe interruptible load if the remuneration offered is financially interesting to it, given the costs and lost revenues that would result from an interruption. In Labrador West, IOCC and Wabush Mines appear to be the only existing entities

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[35] GRA, Vol. 1, page 5.26.

[36] Hydro-Québec Distribution, *Approvisionnements* (Supply), Régie de l'énergie file R-4011-2017, HQD-6, doc. 1, page 8 of 18, lines 8-9.

large enough to provide significant quantities of interruptible load. **Hydro should engage in discussions with them to determine how much curtailment could be made available at what cost.**

Furthermore, insofar as the new data centers are engaged in "bitcoin mining" or other blockchain computing, as opposed to providing real-time internet services, they may also be able to curtail their loads when required. **Including such curtailment as part of service contracts for future data centers could contribute to mitigating their impacts on the Labrador West transmission system, and hence on power costs throughout Labrador.**

Such interruptible loads can be thought of as one category of *demand response*, which refers broadly to a wide variety of demand-side measures to reduce need for peak capacity resource. Earlier this year, a useful review of utility demand response programs was produced by Synapse Energy Economics Inc. in the context of a hearing on Hydro-Québec Distribution's 10-year supply plan.[37] This report may be useful to Hydro and to the Board in considering ways to mitigate capacity requirements going forward. A copy of this report is provided in Appendix B.

3.4. Labrador Industrial Transmission Rate

3.4.1. Network addition policy

In the 2013 GRA, Hydro proposed for the first time a Labrador Industrial Transmission Rate (LITR). In my testimony in that proceeding, I raised a number of concerns with respect to the LITR, particularly with respect to the treatment of the costs of network additions required to provide service to new customers.[38] The Board summarized these arguments as follows:

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[37] Hopkins, A.S. and Whited, M., Best Practices in Utility Demand Response Programs, Régie de l'énergie file R-3986-2016. The report can be downloaded at: http://publicsde.regie-energie.qc.ca/projets/389/DocPrj/R-3986-2016-C-RNCREQ-0021-Preuve-RappExp-2017_04_05.pdf

[38] Raphals, P., Comments on NLH Amended GRA (for Innu Nation), June 23, 2015, pages 43-54.

> Innu Nation argued that the Labrador Industrial transmission rate should not receive final approval until a policy has been established on the allocation of network upgrade costs in a way that protects existing customers. According to Innu Nation, approval of the Labrador Industrial transmission rate has the potential to increase costs to be borne by existing industrial and domestic customers on the Labrador Interconnected system as a result of the costs caused by the new customers. Innu Nation stated that approval of the proposed rate could signal to potential industrial customers that network upgrade costs for new entrants may be passed on to existing customers. Innu Nation referenced Mr. Raphals' evidence relating to the potential additional cost to existing customers and the need to expand the current methodology to reflect new industrial customers entering the system.[39]

Hydro agreed, in part:

> In reply to Innu Nation's submission Hydro acknowledged that it does not disagree in principle with the nature of the issues raised and that the nature of the rate is perhaps too simplistic and doesn't consider some of the factors that may be faced in the future. Hydro noted that, at present, the costs in the Labrador transmission system are fairly linear and simple. Hydro recognized that, as circumstances change, the issues will have to be reviewed and at that time consideration will be given to incorporating some of the principles outlined by Innu Nation. Counsel for Hydro concluded:
>
> > I think it's just premature, but we don't disagree in principle with the nature of the issues he's raised, and, in fact, we look forward to dealing with Mr. Luk and other customer groups in the Labrador Interconnected System when that time comes, and I do expect that time will come in the next few years because things will obviously become more complex in that regard as the system changes.[40]

Partly in response to these concerns, the Board approved the LITR first on an interim basis, and then on a final basis, but for existing customers only:

> The Board accepts that there may be issues which need to be addressed with respect to the allocation of Labrador transmissions costs, <u>particularly the costs associated with a new customer on this system</u>. The Board notes Mr. Raphals' evidence that the federal regulator in the United States, FERC, developed a transmission upgrade policy based on the principle that transmission investments required by participants in the competitive market must not impose new costs on existing rate payers. Hydro did not disagree in principle with Innu Nation but suggested that it may be premature to raise these issues now, although they may have to be addressed sometime in the future.

[39] P.U. 49(2016), page 108.

[40] Ibid., page 109.

> The Board is satisfied that the proposed Labrador Industrial Transmission Rate is reasonable and appropriate in the current circumstances and that it should be approved on a final basis for existing customers. The Board notes that a review of Hydro's cost of service methodology is pending, which may be an appropriate time to address these issues. In the meantime, if a new customer enters the system Hydro will be required to make application to the Board for approval of rates.
>
> **Hydro's proposed interim Labrador Industrial Transmission Rate will be approved on a final basis for existing customers. Hydro will be required to file a revised rate sheet to reflect that this rate is available to existing customers only.**[41]

Until now, it appeared that any significant new loads in Labrador would be industrial loads (e.g. in the mining sector), and so it was appropriate for the debate about ensuring that new users do not create significant costs for existing users take place in the context of the Labrador Industrial Transmission Rate. Now, however, in light of the new information cited above regarding data centers and the uncertainty with regard to the tariff under which they would be served, it appears necessary to broaden the discussion to include general service tariffs as well.

Several regulatory principles come into play here, and they do not all pull in the same direction. On the one hand, it is generally understood that all users receiving the same service should pay the same rate. This principle argues against "vintaging", whereby users receiving the same service would pay different rates depending on the date when they initiated service.

On the other hand, there is the principle of cost causality — that a user should pay the costs that he causes or, stated conversely, that no user should be asked to pay costs caused by another user.

For large users, the first principle generally yields to the second through the utility's discretion to decline or to apply special conditions to service applications above a certain threshold. Thus, if accepting a large service application would create additional costs, those costs can be assigned to that user in its service contract.

Hydro clearly has the capacity to assign costs to users that cause them. In describing its network addition policy, Hydro does not distinguish between industrial or other users, and indeed, it is

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[41] Ibid., page 110.

only in Labrador that there is a distinct transmission tariff for industrial users. Hydro describes its network addition policy as follows:[42]

> Hydro's past practice with respect to network additions has been that network additions have been either: 1) specifically assigned to a single customer if the transmission addition was provided solely to provide service to that single customer; or 2) to treat the network addition as a common transmission asset. The recovery of costs related to specifically assigned transmission assets are recovered from the customer benefiting from the use of the specifically assigned asset. The recovery of costs related to common transmission assets are generally recovered from the customers served by the common transmission system.

Thus, under this policy, network additions that would not be required but for the service request are nevertheless treated as common assets, with their costs shared by all users. Under this policy, the cost of assets made necessary by a single user would inevitably be socialized, except when those assets serve only that user.

This current network addition policy in inadequate to respond to the issues raised here, because it allows situations to occur where one user's needs create significant costs borne by other users.

Due largely to FERC's efforts in the 1990s, utility practice in other jurisdictions has generally moved beyond this binary approach to network additions. FERC policy is designed to protect existing transmission customers from excess costs resulting from network upgrades that are needed in order to provide service to new users.

I described this policy in this regard in my testimony in the preceding GRA, and here quote relevant excerpts:[43]

> To the best of my knowledge, the NLPUB has never had to address the issue of the allocation of costs resulting from transmission system expansion until now, as it has never had a distinct transmission tariff. However, many other regulators, most notably the Federal Energy Regulatory Commission (FERC) in the United States, have devoted considerable

[42] IOC-NLH-033, pages 1 and 2 of 3.

[43] Raphals, P., Comments on the Amended General Rate Application of Newfoundland and Labrador Hydro (on behalf of Innu Nation), June 23, 2015, pages 49 through 51.

attention to this issue — precisely to avoid results like those shown in Table 16 and Table 17, where native load rates increase dramatically as a result of providing transmission service to a non-regulated entity.

While the frontier between federal and state jurisdiction in the U.S. with regard to electricity is complex, it is safe to say that FERC has jurisdiction over the wholesale electricity market, including transmission.[44] Under the legislative mandate to promote competitive power markets provided by the Energy Policy Act of 1993, FERC undertook a major revision of transmission regulation, which eventually led to the issuance of Order 888 in 1996. Order 888 and its accompanying pro forma Open Access Transmission Tariff (OATT) were crafted so as to oblige transmission-owning utilities to let third parties use their transmission systems on the same terms as they do themselves. It is no exaggeration to say that Order 888 and its successors (especially Order 890 of 2010) were responsible for the creation of the competitive power market in the United States. In the process, they have become the standard for transmission regulation throughout North America.

While FERC has no jurisdiction in Canada, most large transmission-owning utilities in Canada have subsidiaries or affiliates for whom the right to transact freely in the United States is very important. Order 888 has reciprocity requirements, which essentially require any utility that makes use of an open access tariff to offer similar open access on its own transmission system. Furthermore, FERC's system for issuing power marketer authorization — necessary in order to transact freely in US power markets — also requires that the marketer's transmission-owning affiliates have open access transmission tariffs that meet or exceed that standards set, first, by Order 888, and now, by Order 890. As a result, most transmission-owning Canadian utilities have open access transmission tariffs that meet these standards.

For all these reasons, the transmission ratemaking policies established by FERC have become a widely accepted standard in North America. Situations like the one presented by the Labrador West Transmission Project, in which an expensive transmission upgrade is needed to provide service to a new industrial customer or other user of the transmission system, are common in other jurisdictions, and the regulatory mechanisms that are applied to them are well known.

…

<u>FERC policy for network upgrades</u>

[44] "FERC regulates the transmission and wholesale sales of electricity in interstate commerce." http://www.ferc.gov/about/ferc-does.asp.

A concise summary of FERC policy regarding network upgrades was prepared last year by Judy W. Chang of the Brattle Group.[45] The relevant excerpt is attached to this testimony as Appendix A.

Ms. Chang explains that:

> The network upgrade policies in the U.S. center on protecting existing transmission customers from excess costs induced by network upgrades associated with customers requesting transmission services. (p. 4)

She adds:

> At the time of restructuring, FERC's primary policy objective was to ensure that transmission providers offered non-discriminatory open access to the transmission network, particularly for customers that were not traditional native load. However, since native load customers, prior to restructuring, had funded (and were going to continue to fund) the infrastructure that made the delivery of power to them possible, FERC also wanted to ensure that existing transmission users would not be unduly harmed by costs imposed by customers requesting transmission service involving network upgrades that could increase the embedded costs of the system. Thus, FERC's initial "higher of" policy was designed to ensure that existing (and growing) native load was protected, while the wholesale market developed, allowing new customers to interconnect to the existing transmission network that was predominantly funded by existing native load. In a policy statement in the mid-1990s, FERC stated that one of the goals of its new pricing policy was "to hold native load customers harmless."[5]

While FERC's jurisdiction is limited to wholesale electricity markets and to interstate transmission, this policy also flows through to retail customers, since the distribution entity that has to pay the upgrade costs will generally seek to recover those costs from the customer that caused them.

If Hydro operated under a functional separation regime — which appears to be implied in the creation of the Newfoundland and Labrador System Operator ("NLSO"), discussed in the next section — then the NLSO would charge NLH for the additional transmission costs flowing from these service additions, to ensure that they do not flow through to other wholesale users of the

[45] The report was prepared on behalf of Hydro-Quebec and filed before the Quebec Energy Board, in support of an application to modify HQ's network upgrade policy. The details of that policy do not concern us here.

NL transmission system. NLH could then pass these costs on to the customers who caused them, as a condition of service.

If no such steps are undertaken, these data centers will benefit unfairly from the NL regulatory regime, which will allow them to take advantage of a limited pool of very low-priced power (the recall block) and to offload onto other users the additional transmission costs required to serve them.

3.4.2. Proposed rate design

Before leaving the subject of the LITR, we will briefly address the modification proposed in the GRA, whereby Hydro proposes to replace the LITR with a two-part rate, to which it attributes some of the characteristics of a seasonal rate. No change is proposed with respect to network upgrade costs.

Under the interim LITR, the industrial user pays the monthly billing rate ($1.19/kW-month) for 100% of its Power on Order. Under the proposed modification, it would pay a fixed billing rate ($1.34 in 2018 TY and $1.86 in 2019 TY) for 90% of its Power on Order, and a higher rate ($2.83 in 2018 TY and $3.95 in 2019 TY) for actual usage each month above that level.

Hydro claims that the proposal has "a similar seasonal effect" to a seasonal tariff, though it does not have an explicit difference between winter and non-winter periods.[46] It further states:

> The proposed rate achieves a similar seasonal effect as <u>customer demand minimally exceeds 90% of Power on Order during summer months</u>. Therefore, the opportunity for savings that can be achieved by the customer through reduced demand in the summer months is materially less than the opportunity for savings that can be achieved by the customer through reduced demand in the winter months.[47] (underlining added)

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[46] LAB-NLH-034, page 2 of 2.

[47] LAB-NLH-061, page 2 and 3 of 3.

It is not clear if the underlined phrase is meant to refer to all industrial customers in general, or to one customer in particular.

The change is intended to be revenue neutral, and a numerical demonstration for 2018TY is provided.[48] The table does indeed demonstrate identical revenue under the existing and proposed rate designs, but it displays an anomaly. For Wabush, the amount billed under the Excess Block is precisely 10% of the current billing demand[49]. However, for IOCC, it is considerably less: 170,000 kW, compared to 294,000 kW (10% of the current Billing Demand). This may reflect actual power usage by IOCC — if its summer demand is less than its Power on Order, it would effectively use less than 100% of the available Excess Block, and so be charged less for it. However, were it to use 100% of the Power on Order in every month, its annual bill would increase under the Proposed Rate Design.

In a sense, then, the change can be seen as making the last 10% of the Power on Order interruptible, at the customer's option. Whereas, under the exist rate design, the customer has to pay for 100% of the Power on Order, under the proposed design, it can reduce its transmission cost by reducing that amount by up to 10%. The inclining block structure provides additional incentive to do so.

The fact remains, however, that the proposed rate provides equal incentive to reduce demand in the summer as in the winter. As the transmission system constraints occur in the winter[50], this structure provides little incentive to resolve them.

Hydro has indicated that it "does not rule out the use of seasonal pricing as a vehicle for rate design in the future"[51]. We encourage it to continue to explore these options.

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[48] IOC-NLH-027, Table 1, page 3 of 3.

[49] The title of the second column is misleading, as the amounts indicated are apparently not identical to the Power on Order.

[50] LAB-NLH-061, page 3 of 3, lines 10 to 12.

[51] HAB-NLH-034, page 2 of 2.

4. NEWFOUNDLAND AND LABRADOR SYSTEM OPERATOR

In section 3.8.3 of the GRA, Hydro describes the creation of the Newfoundland and Labrador System Operator (NLSO), as follows:

> In accordance with FERC standards, the Newfoundland and Labrador System Operator (NLSO) has been created to act as the independent system operator for the Province. Although the NLSO will reside within Hydro, it will operate the facilities owned by Hydro, Nalcor Power Supply, and interconnections with Emera's Maritime Link assets on the Island. The NLSO will represent all interests on the transmission and distribution network and will be governed by a set of rules and regulations that ensures fair and equitable treatment of all entities seeking access to the network.[52]

In the exhibits, Hydro further states:

> The NLSO will reside in Hydro but will be functionally separate and will act as the independent system operator for the transmission system in the Province. <u>It will operate the facilities owned by Hydro and Nalcor along with interconnections to Emera's Maritime Link assets on the island</u>.[53] (underlining added)

In response to RFIs, Hydro adds that:

- The NLSO was created in consultation with the provincial government;[54]
- that it has commenced separate functional operations, but will not be fully operational until procedures are in place with respect to open access;[55]
- that there are no functions within Hydro that have to remain functionally separate from the NLSO, and no affiliate marketing operations with Hydro from which a Standard of Conduct would be required.[56] If Hydro is in a position of having committed to take more

[52] GRA, page 3.45.

[53] Exhibit 2 (Organizational Responsibility), Section 4.3, pages 3 and 4.

[54] LAB-NLH-042, page 3 of 3.

[55] Ibid., page 2 of 3.

[56] LAB-NLH-043, page 2 of 2.

electricity than its customers might require at any given moment, the excess can be exported by Nalcor Energy Marketing on behalf of Hydro's customers;[57]

- that the NLSO will be responsible for all transmission operations in Labrador, including the operation of the 735-kV lines running from the Churchill Falls Generating Station to the Quebec border. [58] Hydro is in discussions with Hydro-Québec on this issue, which it characterizes as "very preliminary" but no agreement has been reached, even on these general principles. Hydro fully expects that an agreement will be reached between the three parties but, in the event that this does not occur, it is "examining various options to make an exchange at the border"; [59]
- The Maritime Link (ML) will be under operational control of the Nova Scotia Power System Operator (NSPSO). The interface between the two system operators is defined by an agreement that is in force, and an Interconnection Operators Committee has been formed with representation from both the NLSO and the NSPSO that meets regularly in order to allow for safe and reliable integration of the ML into the NL and NS transmssion systems;[60]
- The NLSO will also have the role of Balancing Authority for both the Island and Labrador regions, including the Churchill Falls Generating Station. [61] Hydro is in discussions with Hydro-Québec on this issue, which it characterizes as "very preliminary", but no agreement has been reached, even on these general principles. Hydro fully expects that an agreement will be reached between the three parties but, in the event that this does not occur, it is "examining various options to "achieve balancing in Labrador";[62]
- The NLSO will collect the transmission tariff from all transmission customers, and remit the amounts received to the transmission asset owners (including for the Labrador-Island Link and the Labrador Transmission Assets) in accordance with their revenue requirements;[63]

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[57] LAB-NLH-065, page 2 of 2. The response also refers to the possibility that such an excess could be "deferred for future use", but no explanation is provided for the mechanism of such a deferral.

[58] LAB-NLH-044, page 2 of 3.

[59] LAB-NLH-066, page 2 of 2.

[60] Ibid., page 2 and 3 of 3.

[61] LAB-NLH-045, pages 1 and 2 of 2.

[62] LAB-NLH-067, page 2 of 2.

[63] LAB-NLH-063, page 2 of 3. No mention has been made of an agreement with CF(L)Co with respect to charging for the use of its 735-kV transmission lines

- The transmission owners will provide their revenue requirements to the NLSO, after obtaining any necessary regulatory approvals. The NLSO will then apply to the Board for approval of a transmission tariff that will collect sufficient revenue from transmission customers to fulfill these revenue requirements;[64]
- All transmission users, including Hydro, will pay the same transmission rates for the same transmission services. Under OC2013-343, Island transmission users will cover 100% of the cost of the LIL and the LTA.[65] Presumably then there will be separate transmission tariffs for the Island (including the LIL and the LTA) and for Labrador.

With respect to an open access transmission tariff, Hydro affirms that the NLSO will offer open and non-discriminatory transmission access to all transmission customers, including Nalcor affiliates and non-affiliated third parties.[66] It states that preparatory work on the OATT has begun,[67] and it provides an indication of how it will function:

- Hydro will apparently be the only holder of firm transmission rights;
- Transmission rates for firm service by dividing the annual revenue requirement by the "sum of firm billing determinants", and dividing that amount by 12;
- Transmission rates for Non-firm hourly service would be determined by dividing that amount by the number of hours in the month;
- Revenues from non-firm service would be taken as a credit against the following year's revenue requirement.[68]

The transition to the NLSO is unlikely to be a simple path. Even in the absence of the uncertainties with respect to Hydro-Québec, the transition from a vertically integrated utility to a quasi-independent system operator will inevitably be far more complicated than one would surmise from reading these few pages of evidence.

As described in the evidence, this transition is an initiative of Hydro, taken under "consultation" with the provincial government and, apparently, without substantive consultation with the Board.

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64 Ibid.

65 LAB-NLH-064, pages 2 and 3 of 3.

66 Exhibit 2, page 4.

67 LAB-NLH-046, page 1 of 1.

68 CA-NLH-175, pages 1 and 2 of 2.

This is a surprising path. Most often, significant utility restructuring is driven by legislation; in a few cases, by regulatory action.

It is clear that, before this initiative is completed, the Board will be called upon to approve a number of complex documents, including an open access transmission tariff and codes of conduct. In Quebec, the hearing that led to the approval of HQ-TransÉnergie's first OATT lasted over two years.[69] The main decision was 385 pages, and it was followed by 13 other decisions, not including those concerning intervenor cost awards.[70] The sheer scale of these undertakings could overwhelm the available resources on the part of the utility, the regulator and the interested parties.

The situation is further complicated by the complex and litigious relationship between Nalcor/NLH and Hydro-Québec. Hydro identifies two important issues with respect to which discussions with Hydro-Québec are "very preliminary" and "no agreement has been reached, even on general principles". It would be surprising if these issues were to be resolved quickly.

Hydro has not explained its choice of the System Operator model, as opposed to the much simpler model of a functionally separate transmission operator within an integrated utility. It would be helpful if Hydro were to share with the Board and the interested parties a roadmap encompassing all the structural changes it intends to undertake, to allow reasoned consideration of the best path forward.

[69] Régie de l'énergie file R-3401-98, http://www.regie-energie.qc.ca/audiences/3401-98/index.html.

[70] http://www.regie-energie.qc.ca/audiences/3401-98/mainDecisionsRegie.htm. The Régie's first procedural decision was issued in November 1999. Its main decision was issued in April 2002, and the last followup decision in June 2004.

QUALIFICATIONS

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, utility regulation (including transmission ratemaking) and green power certification. He is the author of numerous studies and reports and frequently appears as an expert witness in the regulatory arena.

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

In 1997, he 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*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals appeared as an expert witness in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which retained many of his suggestions. He also presented testimony to the Newfoundland and Labrador Public Utilities Board in the context of its advisory hearings concerning the Muskrat Falls project.

Last year, he presented expert testimony to the Nova Scotia Utility and Review Board in the proceedings concerning the Maritime Link, on behalf of the Canadian Wind Energy Association and, for the compliance phase, the Low Power Rates Alliance.

In British Columbia, he provided expert testimony in 2014 on behalf of the Treaty 8 Tribal Association before the Joint Review Panel examining the proposal to build the Site C Hydroelectric Project. This year, as part of a team led by Dr. Karen Bakker of the University of British Columbia's Program on Water Governance, he was coauthor of a major study on Site C

(*Reassessing the Need*) and of several submissions to the British Columbia Utilities Commission's inquiry on the same subject.

Mr. Raphals is a frequent expert witness before the Quebec Energy Board (the Régie de l'énergie du Québec), where he has provided testimony concerning transmission tariffs (FERC), the integration of wind power, security of supply with respect to hydropower, energy efficiency and avoided costs, and sustainable development criteria. He also chairs the Renewable Markets Advisory Panel for the Low Impact Hydropower Institute (LIHI) in the United States.

APPENDIX A

GREAT NORTH DATA (INDEX.HTML)

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— GREAT NORTH DATA —

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PLEASE CHECK WITH US BEFORE SENDING ANY EQUIPMENT!

ABOUT GREAT NORTH DATA

In 2013, Great North Data started operating their hardware in the Canadian province of Newfoundland and Labrador and never looked back. The realization that their efficient operation could benefit many other hardware operators lead to the creation of Great North Data.

HOSTING

Great North Data specializes in hosting high-density computer hardware requiring substantial access to both power and cooling.

LOW-COST POWER

Great North Data has secured contracts providing us with green hydroelectricity at one of the lowest prices globally.

ECO-FRIENDLY COOLING

Many data centres use inefficient air conditioning systems to provide cooling which carry over large costs to their customers. Our custom-designed HVAC system is much more cost effective and with its low power footprint, environmentally friendly.

INDUSTRY-LEADING PRICES

Our low overhead costs allow us to provide our customers with industry-leading prices to keep their bottom-line in check.

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PHOTOGRAPHS

Great North Data has expanded operations in Labrador to increase our total hosting capacity to over 6 MW. Here are some photos of our new facility during construction and after the deployment of new hardware.

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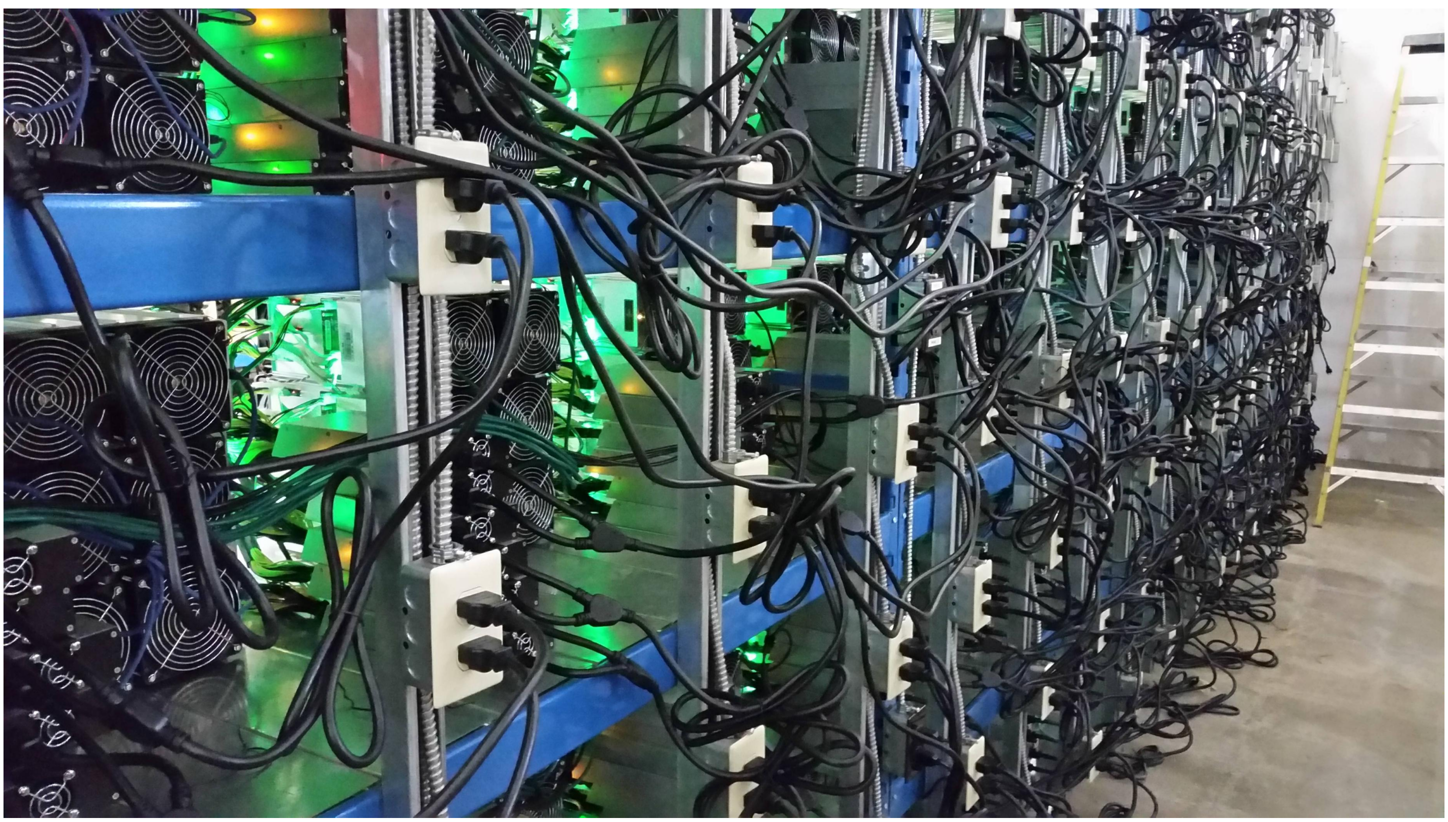

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'It's the new emerging thing': Mining for data in western Labrador

By Jacob Barker, CBC News Posted: Jul 26, 2016 6:59 AM NT Last Updated: Dec 08, 2016 11:53 AM NT

Iron ore towns in western Labrador are positioning themselves for a different king of mining, one that involves computers, bitcoins and data storage.

- **Argentia bunkers poised to be data centre**

There are no hauling trucks or heavy machinery — just two former storefronts in Labrador City.

"Data mining is essentially what this is," said Bob Griffin, a co-founder of Great North Data (GND).

"And it's interesting that we've gone to a mining town to do a different kind of mining."

Companies use data centres as third party storage for their data. They can use them as clouds or archives, or in the case of GND, a tool to mine for bitcoins.

Bitcoins are an online currency. Mining them is much different than mining for iron ore. They are created by computers solving mathematical equations. Computers are used to solve these equations and are issued bitcoins in exchange.

"It's what's growing, it's the new emerging thing and we wanted to really cater to that because we think that's where the opportunity really lies," Griffin told the CBC

GND already has one centre set up in Happy Valley-Goose Bay. A gutted green building on Avalon Drive will soon be filled with rows and rows of computers running equations.

Another company, North 53 degrees, that is setting up in an old mall in the Harrie Lake subdivision, declined our request for an interview.

Power supply, cold climate

Labrador West is seen as an ideal location for a couple of reasons.

"Just like iron ore mining, energy cost is crucial in breaking even and profiting," said Griffin.

"The situation is there is surplus power in Labrador West and they don't have a use for it right now and we are filling a huge gap that's been left by the iron ore industry."

- **Bruised businesses feeling the sting of Lab West downturn**

Another incentive is the climate.

"These machines get very hot and it saves a lot of money if you can cool them with cold air outside," said James Goodwin, also a co-founder of GND.

> 'We are filling a huge gap that's been left by the iron ore industry.' *- Bob Griffin, Great North Data*

"Lab West climate is perfect for data centres. You couldn't have picked a spot that's colder that has access to this kind of electricity."

GND is based out of St. John's and keeping the business in the province is also something that's important to the company.

"I'm from St. John's and I'm very pro-Newfoundland and Labrador and I feel this has long since been needed, talked about and I'm really happy to be part of something we can bring to Lab West and we can help diversify and help grow small economies," said Griffin.

Open for business

"We've had some success with data warehousing and I think that will even grow more as we move into the future," Labrador City Mayor Karen Oldford told the CBC.

The mayor sees it as a way for the town to diversify — new industry in a town where there is so much uncertainty around the iron ore industry.

"We're open for business, for that type of business, and we see this industry as a major part of a diversification plan," the MHA for Labrador West Graham Letto said.

"It doesn't create a whole lot of jobs but it generates jobs and every job today is important."

The immense amount of power needed is of concern to Wabush Mayor Colin Vardy.

He said the town has been approached by a data centre company out of China. He has some concerns before deciding how to proceed.

"We have to make sure the power is available but we also have to make sure too that we don't chew up any power that would be needed for the iron ore industry if Wabush Mines were to come back to life or if Alderon were to come on board," Vardy said.

Dave Pearson is a researcher at International Data Corporation and specializes in enterprise storage and networking in Canada. He said though the power draw is heavy, it isn't crippling.

"When you're looking at what's going on in Labrador for example, those kinds of implementations will not provide a great deal of strain on the local grid and certainly not on a province wide or country wide scale," he said

High demand

Pearson said the biggest data centres are in the United States but the market continues to pick up steam in Canada.

"In a very off quarter, Google adds about twice as many servers to their existing stable of servers as the entirety of Canadian enterprise adds," he said.

"So investments in data centres and technology are really key to pushing the envelope on productivity for Canada."

GND seems to have its hand on that envelope. Anybody who might want in on their not-yet-completed data centre is already out of luck.

"It's functionally 100 per cent full and we're not even done yet, and there's an urge for more," said Goodwin.

And those making use of it are from all over the world. The team said there's global interest in Labrador.

"No-one's ever built a blockchain data centre in Canada this large before and to a large extent, we're kind of creating a plan as we go," Goodwin said, blockchain referring to the dedicated bitcoin equipment.

GND said better infrastructure would be needed if bigger companies like Facebook or Amazon were to take interest.

"Unfortunately there's only one trunk line running into Lab West right now," Goodwin said.

"We already have competition following us here but if they put the investment in the fibreops network, there will be more."

DatacenterDynamics
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Data center in Labrador City hopes to silence noise complaints

12 December 2016 **By Max Smolaks**

Canadian Bitcoin mining facility is a headache for its neighbors

A newly built data center in Labrador City is in trouble with the local government, following complaints that the noise from the facility operated by Great North Data is causing headaches among residents of neighboring properties.

According to CBC News (URL=http://www.cbc.ca/news/canada/newfoundland-labrador/data-centre-testing-noise-complaints-labrador-city-1.3884847) , some local homeowners have been forced to keep their windows closed, and even wear earplugs at night.

Great North Data (GND), which offers blockchain services and cryptocurrency mining, said the equipment was being unusually loud while it was going through the testing phase. The company is adopting a number of measures to improve the situation.

Respect the neighbors

Great North Data's first facility is located in Labrador City, part of the Canadian province of Newfoundland and Labrador where power is cheap since most of it is derived from hydroelectric dams.

The company hopes to build Canada's largest facility for Bitcoin mining. It doesn't engage in mining operations directly, instead offering a colocation service for specialist cryptocurrency equipment. Just like in a traditional colocation data center, Great North Data takes care of space, power and cooling, while its customers have to provide their own mining hardware.

The project suffered a setback after several residents complained about the levels of noise produced by the facility, and criticized the decision to place it in the middle of a residential

Transformer installation on the GND site

Source: Great North Data

district.

In response, Labrador City government issued a statement describing the noise as “intrusive” and ordered the company to address the issue. It promised to purchase sound monitoring equipment, and to set targets for ambient noise that Great North Data will have to meet. It added that it wasn’t planning to stop equipment testing ahead of schedule.

GND said that the location of the data center was chosen due to the availability of high voltage power lines – noting that it was indeed strange that such lines were stretching across a residential area.

The company added that it was doing everything in its power to address noise pollution, with CEO James Goodwin describing all of the issues highlighted by local residents as “fixable”.

Some of the measures proposed by GND include installation of a ‘noise baffling’ wall and sound insulation, and changes to ventilation fan speeds.

Goodwin added that the location of the data center was temporary, with plans to move to a new, larger site in Lab West in a couple of years.

Legal dispute pits Labrador data centre against Chinese bitcoin mining equipment supplier

Court documents outline financial issues getting project off the ground

By Rob Antle, CBC News Posted: Apr 27, 2017 6:30 AM NT Last Updated: Apr 27, 2017 10:06 AM NT

A St. John's-based company that received nearly $1 million in government assistance to help expand its data centre operations in Labrador is now locked in a legal dispute with its business partner, a Hong Kong-based bitcoin mining firm.

Bitmain Technologies sued Great North Data last month, alleging problems pretty much from the start of the agreement between the two companies.

Great North Data denies those allegations, and points the finger at the Chinese firm for not holding up its end of the bargain.

Court documents filed by both sides indicate that Great North Data has experienced financial difficulties since last year.

The company received infusions of $500,000 from the Atlantic Canada Opportunities Agency in December 2015, and another $420,000 from the Newfoundland and Labrador government between January and August 2016.

Neither Bitmain nor Great North Data is doing interviews, but their lawyers both issued statements.

Daniel Simmons, the lawyer representing Great North Data, noted in an email to CBC News that the company "continues to carry on business as usual without interruption at its facilities in Labrador."

Meanwhile, Megan Taylor, who represents Bitmain, says her client "has no direct knowledge of the current status of their equipment," and Great North is no longer hosting for Bitmain.

Bitcoin 'mining farm' in Labrador

Bitmain Technologies develops and produces computers to mine the bitcoin cryptocurrency. It operates some of its hardware out of third-party "mining farms."

Great North Data provides space to companies like Bitmain to install and run their bitcoin mining equipment.

Basically, those computers churn through complex calculations to validate bitcoin transactions. In return, they earn payments that are also made in bitcoin.

In the past, Great North officials have publicly touted Labrador's cold climate and surplus electricity as a perfect combination for the industry.

- **'It's the new emerging thing': Mining for data in western Labrador**

Bitmain signed a deal with Great North last June to have its bitcoin mining equipment hosted at the Labrador City facility.

But problems soon became apparent.

By August, Great North Data "was unable to continue with its construction program to ready the facility for hosting computer equipment due to higher than anticipated construction costs," the St. John's-based company said in court filings.

Great North Data says it told Bitmain "it was considering halting the project."

In an email Bitmain included with its court filings, Great North director James Goodwin wrote Aug. 30 that "we have had significant cost overruns and have failed to find financing to cover them."

Goodwin wrote: "If Bitmain can prepay for the 4 MW three months in advance … then we could finish the project."

They ultimately agreed to a prepayment of just over US$330,000.

Great North says in court documents it could use the money to pay outstanding construction costs. Bitmain says it was supposed to remain in trust.

Bitmain shipped computer hardware and power supplies to Labrador last fall.

The Chinese company alleges in court documents that "operational issues" continued.

Then financial problems again came to the forefront, and the ownership of that equipment is now in dispute.

'We are having huge difficulties'

On Feb. 14, 2017, Goodwin again wrote to Bitmain officials, who included the message in their court filings.

"Obviously, we are having huge difficulties which I hope we can resolve as quickly as possible," Goodwin's email noted.

"Selling the miners is the best way forward for both of us. It will allow Bitmain to divest from the mine with your funds, and it will allow me to have clients who pay a much higher rate. Otherwise I will not be able to pay my employees or power bills. While we have cheap power in Labrador, our cost of employees and labour is very high, much higher than we had expected."

The two sides now disagree over who actually owns the equipment.

Bitmain acknowledges creating an invoice "based on Goodwin's advice" that purported to transfer the equipment.

But Bitmain says that invoice was "solely for use with Canadian customs" so Goodwin could pay import duties and taxes.

"There was no consideration exchanged between the parties," Bitmain noted in court documents.

"Bitmain states that GND's use of the invoice as a means to sell Bitmain's property without permission was unlawful and constitutes … civil fraud, theft and conversion."

Bitmain sued to get its equipment and trust account money back, and for damages.

Meanwhile, Great North has filed a countersuit alleging breach of contract and seeking US$1.4 million in damages.

The company says it can sell the equipment, and alleges that some of it was defective.

Great North indicated in court filings that it "arranged the sale to third parties of 424 working bitcoin miners and power supplies. That equipment remains located at the facility and is operated under hosting agreements with the buyers."

Last month, Newfoundland and Labrador Supreme Court Justice Deborah Paquette issued a temporary restraining order stopping the equipment from being sold or moved until its fate is decided at a later hearing.

Status of federal, provincial funding

While Great North Data is in conflict with a major business partner, it has no such issues with its government funding agencies.

In an emailed statement to CBC News, ACOA says Great North Data is in good standing, and is on schedule in paying back the $500,000 investment to the agency.

The Newfoundland and Labrador government, which provided a $420,000 contribution, also indicated that Great North Data is in good standing.

In an email last Wednesday night, the Department of Tourism, Culture, Industry and Innovation said the current balance owing on repayment is about $386,000.

The department said all securities are in place, and all terms and conditions are current and compliant.

Bell Aliant zeroes in on Labrador fibre op break

CBC News Posted: Nov 26, 2013 11:54 AM NT Last Updated: Nov 26, 2013 5:50 PM NT

Bell Aliant said Tuesday it had narrowed down the area of a breakdown in its fibre op line near Labrador City.

But the company said technicians were unable to find any physical damage to the line.

The trouble area, about 80 kilometres east of Labrador City, resulted in a loss of internet service in the Upper Lake Melville area and on the north coast of Labrador.

A Bell Aliant spokesperson said workers were able to reroute some internet traffic over its radio network to the east, but noted internet and some cellphone customers would "continue to experience degradation in service quality while we work on the repair."

The company said further testing would be carried out Wednesday as technicians prepare to replace the section of fibre that's causing the problem.

Bell Aliant could not say how long it will take to fully restore service.

Government of Canada Gouvernement du Canada

Support Announced for Projects in Labrador West

News Release

Funding announced for eight community and business initiatives in Wabush and Labrador City

August 18, 2016 – Labrador City, NL – Atlantic Canada Opportunities Agency

Tourism, mining, business and community infrastructure in Labrador West will benefit from Government of Canada and Government of Newfoundland and Labrador investments. The Honourable Dwight Ball, Premier of Newfoundland and Labrador, and Yvonne Jones, Member of Parliament for Labrador, on behalf of the Honourable Navdeep Bains, Minister of Innovation, Science and Economic Development and Minister responsible for the Atlantic Canada Opportunities Agency (ACOA), announced a combined investment of $1,734,083 at an event in the region today.

The Government of Canada is contributing $1,038,083 in federal funding towards eight projects and the provincial government is contributing $696,000 towards four of these projects. An accompanying backgrounder provides details related to all projects.

As part of the recently launched Atlantic Growth Strategy, the Government of Canada and the four Atlantic provincial governments are committed to supporting infrastructure projects in communities across the region. These investments build on this commitment. Communities prosper when all people have affordable and accessible gathering spaces to find support and enrich their quality of life.

Quotes

"The Government of Canada understands the value of partnership and co-operation and works in collaboration with community partners and industry to support economic growth. The investments announced today demonstrate the Government of Canada's commitment to business development as well as community and recreational infrastructure projects that will improve our communities by restoring and upgrading the facilities and areas that bring us together."

- *The Honourable Navdeep Bains, Minister of Innovation, Science and Economic Development and Minister responsible for ACOA*

"The Government of Canada is pleased to work with a variety of community partners in the Labrador West region to advance projects that support stronger communities and a vibrant, growing business climate. The investments announced today will also help create jobs, boost economic activity, strengthen communities and celebrate Canada's rich heritage and history."

- *Yvonne Jones, Member of Parliament for Labrador*

"Our support for these projects demonstrates our government's commitment to increasing economic development and diversification while encouraging private sector growth and innovation. It is our hope that these investments will lead to long-term sustainable employment opportunities for the people of Labrador West."

- *The Honourable Dwight Ball, Premier, Newfoundland and Labrador*

Associated Links

- Canada.ca/150
- Atlantic Canada Opportunities Agency
- Atlantic Growth Strategy

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BACKGROUNDER

Great North Data is using a $500,000 repayable investment from ACOA's Business Development Program and $420,000 from the provincial department of Business, Tourism, Culture and Rural Development (BTCRD) to undertake the expansion of its existing data centre. Specifically, the project will enable the applicant to increase its capacity through the purchase of power transformers, server racks and a HVAC system.

The College of the North Atlantic is receiving a $70,000 investment from ACOA's Business Development Program and $50,000 from BTCRD to conduct a feasibility study to assess the viability of establishing and operating a Centre of Excellence in Mining Support, Innovation and Industrial Research. The overall goal of the project is to determine how the College can meet the current and expected future mining training needs of the province and to support and enhance actions that lead to increased innovation and research opportunities for improved industry competitiveness.

The Smokey Mountain Ski Club Limited is receiving $207,838 through ACOA's Innovative Communities Fund and $210,000 from BTCRD to enhance its downhill ski facility in Labrador West. This includes upgrading the ski chalet, purchasing and installing a magic carpet lift and acquiring timing and site-specific equipment to support club operations.

The Town of Labrador City will use $138,695 from the Canada 150 Community Infrastructure Program (CIP 150) to make improvements to the arena and walking trail in the community. The project includes replacing dasher boards in the arena, as well as improving the Tanya Lake and Warblers Walk trails with interpretive and directional signage and the installation of benches and tables.

The White Wolf Snowmobile Corporation will use a $27,254 investment from the CIP 150 and a $25,000 contribution from BTCRD to undertake improvements to their clubhouse and groomer storage facility, including interior and exterior painting, flooring replacement and resurfacing, installation of an exhaust system and roof replacement.

The Rotary Club of Labrador City and Wabush Inc. is receiving a $50,000 CIP 150 investment to upgrade Rotary Peace Park. This project involves the construction of a central entertainment area to be used for community events.

The Town of Wabush will use a $34,632 CIP 150 investment to install a new chill unit and condenser at the Wabush arena, as well as an $11,918 contribution to enhance the Jean Lake walking trail. Updates to the existing five kilometre trail will include replacement of existing boardwalk, removal of brush, installation of stone where required, repair to bridges and installation of signage.

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Date modified:
2016-08-18

APPENDIX B

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)

March 31, 2017

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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

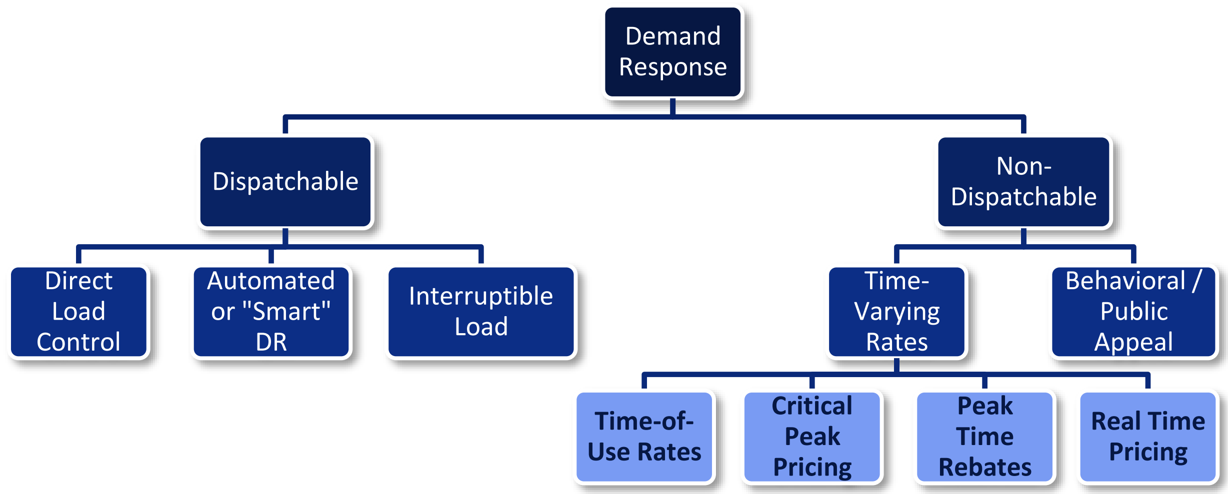
All categories of customers (industrial, commercial, and residential) employing many different technologies or strategies can provide demand response. However, the deployment of such resources generally varies by customer type.

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:

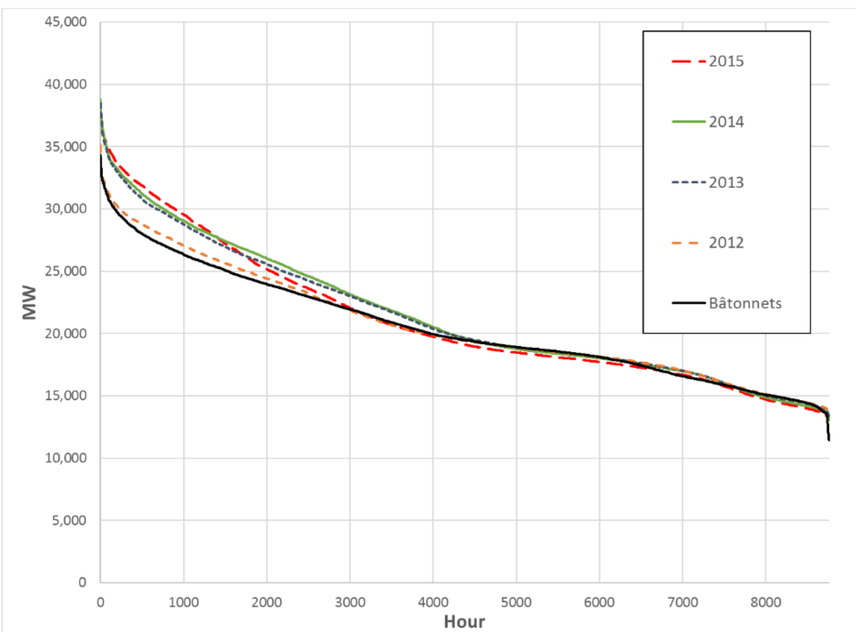
- The power supply portfolio is almost invariant in cost and availability, except during a few peak periods.
- Those peak periods are almost exclusively driven by the coldest winter weather.
- Electric rates are quite low, compared with other provinces or U.S. states and with the cost of fossil fuels 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).

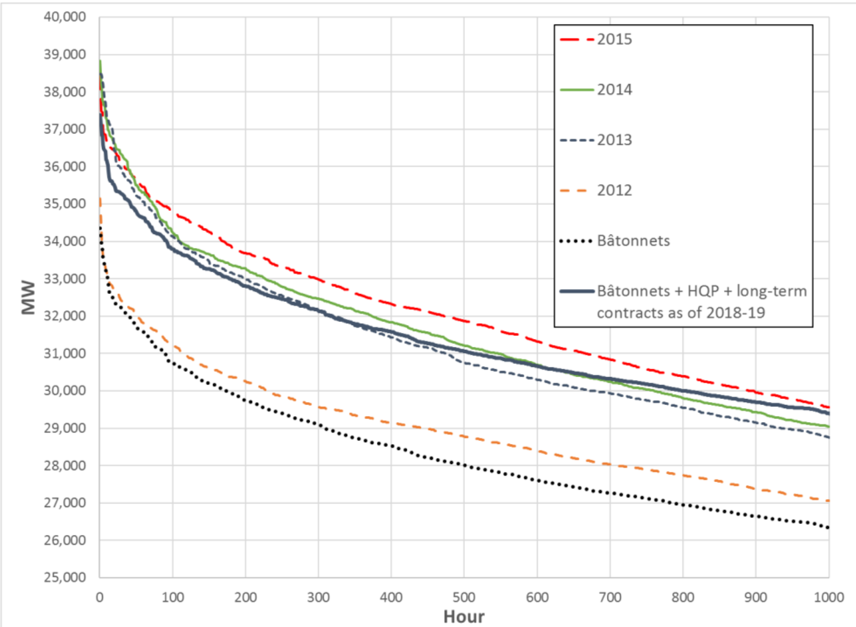
Figure 2 shows HQD's load duration curve for the years 2012–2015, along with the 8,760 "bâtonnets." HQD's power supply portfolio challenge is how to most cost-effectively meet the annual load by building on top of the patrimonial load shape. There is noticeable variation by year, although general trends 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.

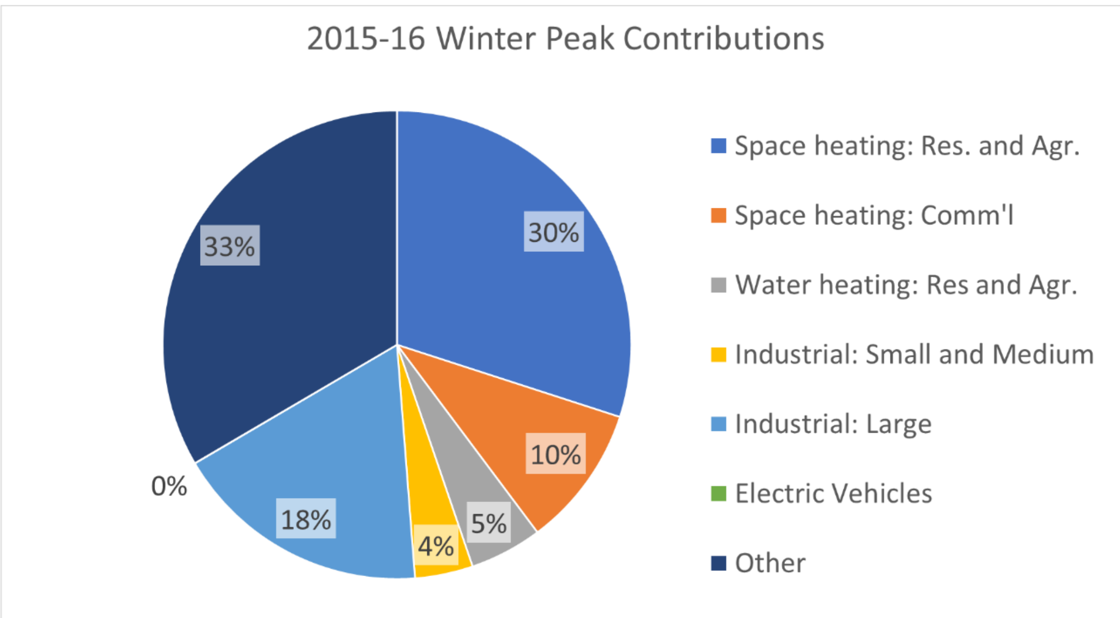
Figure 3 shows the top 1,000 hours of load for the years 2012–2015, along with the top 1,000 "bâtonnets." In addition, the figure shows (solid black line) the "bâtonnets" plus 3,051 MW. These 3,051 MW correspond to the long-term contracts with HQP (600 MW), the A/O 2015-01 tender (500 MW) and the wind, 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.

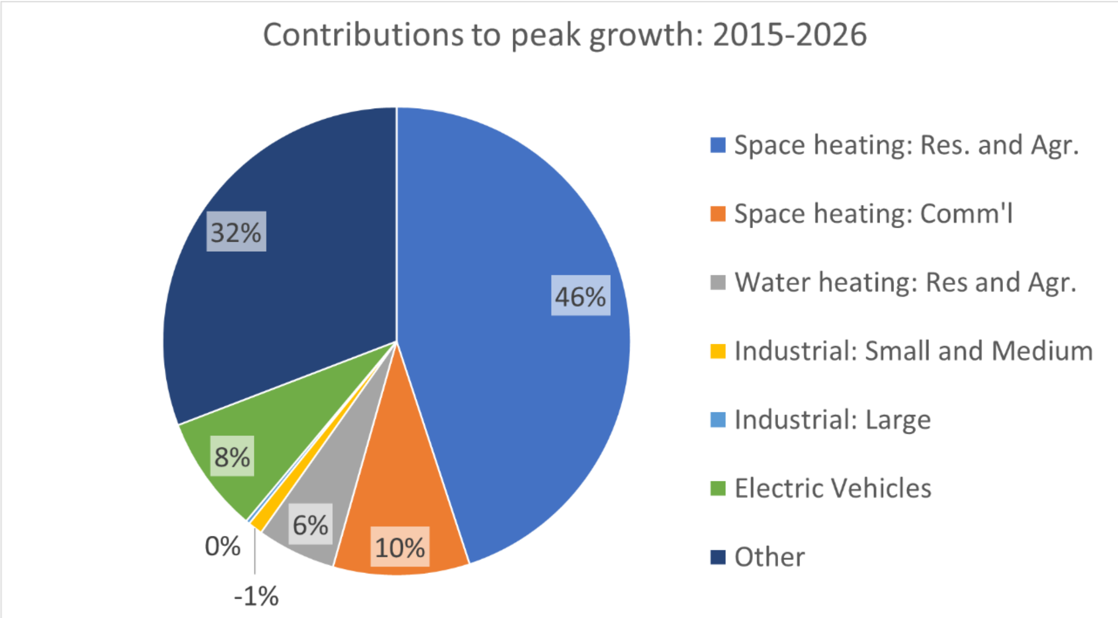
The load characteristics described here lead to a winter peak dominated by space heating, followed by miscellaneous other uses and industrial processes, then water heating; see Figure 4 for the contributions to peak from each end use or sector in 2015–2016. The sources of growth in peak through 2026 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

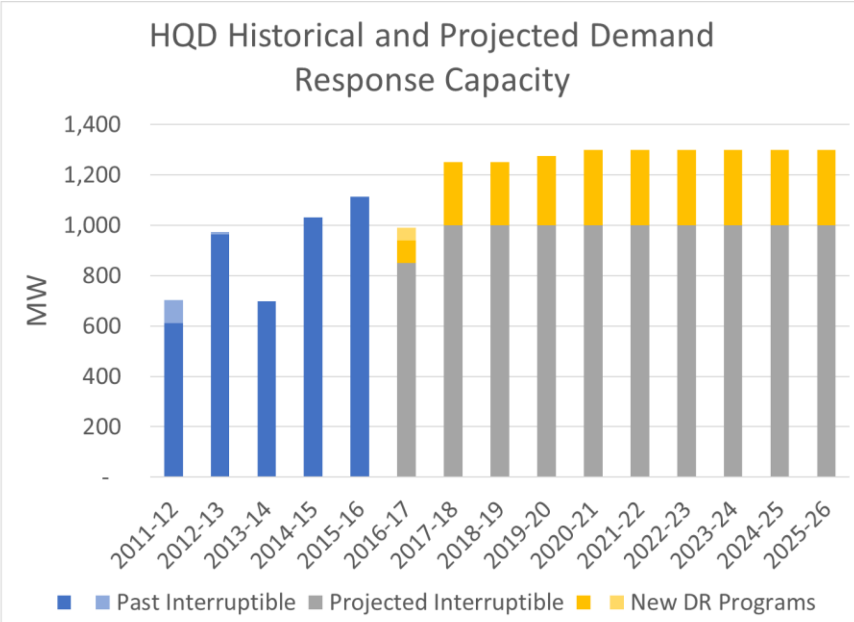
Source: HQD-3, document 2.1 from each of the 2012 to 2015 Annual Reports.

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.

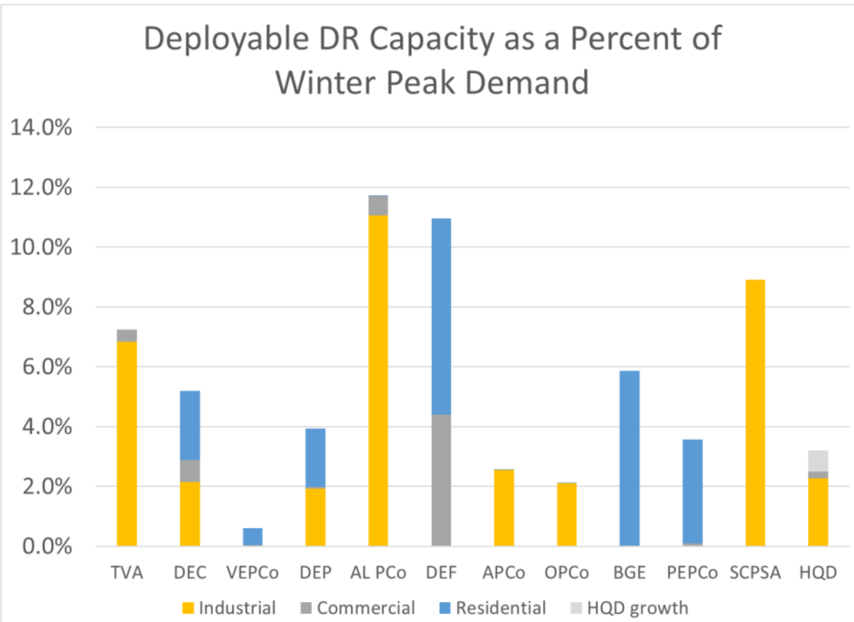
HQD also conducts a kind of critical peak price-based demand response in the form of Rate DT for customers with dual-fuel heating systems. This rate is only available to customers with a second, non-electric heating system (or thermal storage), preferably with automatic switch-over. The rate is triggered 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

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[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.

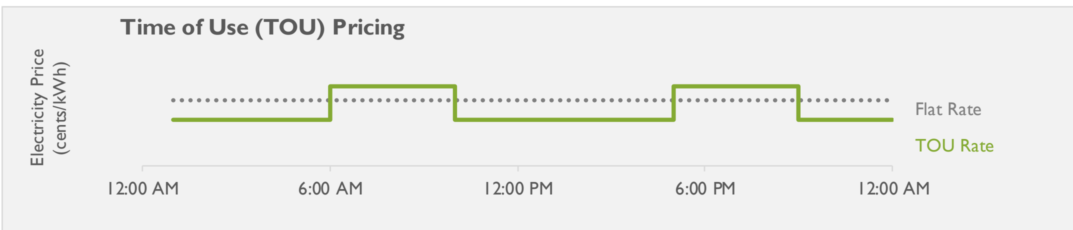
[18] Hledik, R., A. Faruqui, and L. Bressan. 2016. "Demand Response Market Research: Portland General Electric, 2016 to 2035” Preparted by Brattle Group. Available at: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-02-01-demand-response-market-research.pdf?la=en.

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.

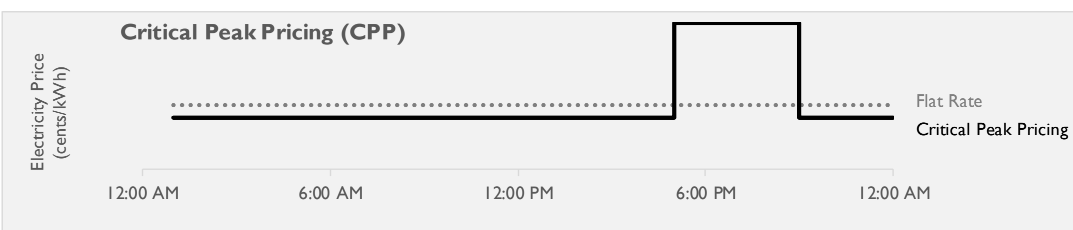
Time-varying rates

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.



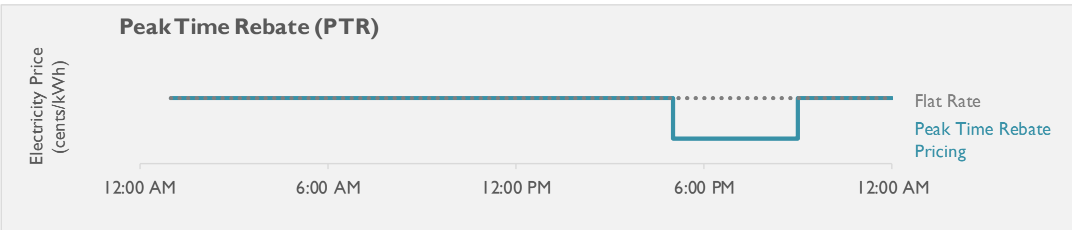
- *Peak Time Rebates (PTR)*: A peak time rebate program is similar to critical peak pricing, except that customers earn a financial reward for reducing energy relative to a baseline, instead of being subject to a higher rate. As with critical peak pricing, the number of

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

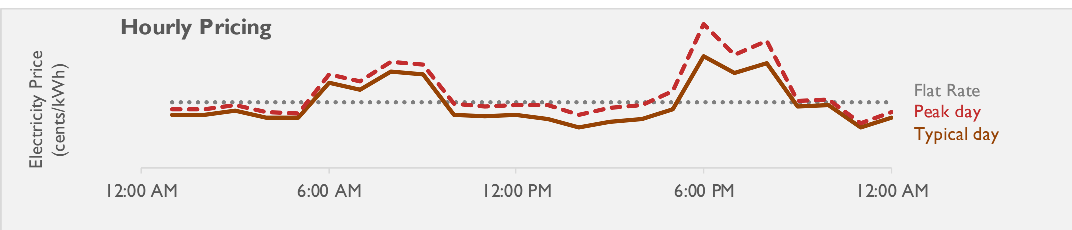
event days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.[20] While PTR programs tend to be widely accepted by customers, they have two drawbacks relative to critical peak pricing:

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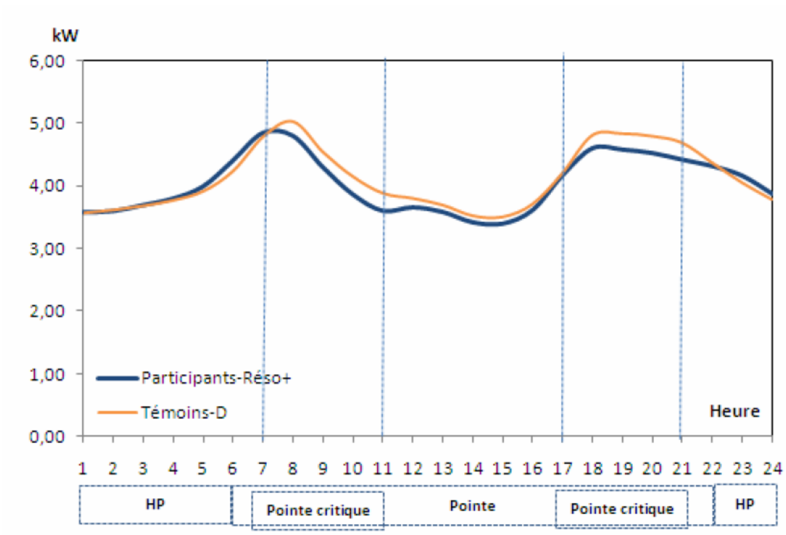
[20] United States of America. Federal Energy Regulatory Commission. *Assessment of Demand Response and Advanced Metering.* Washington D.C.: United States, 2010.

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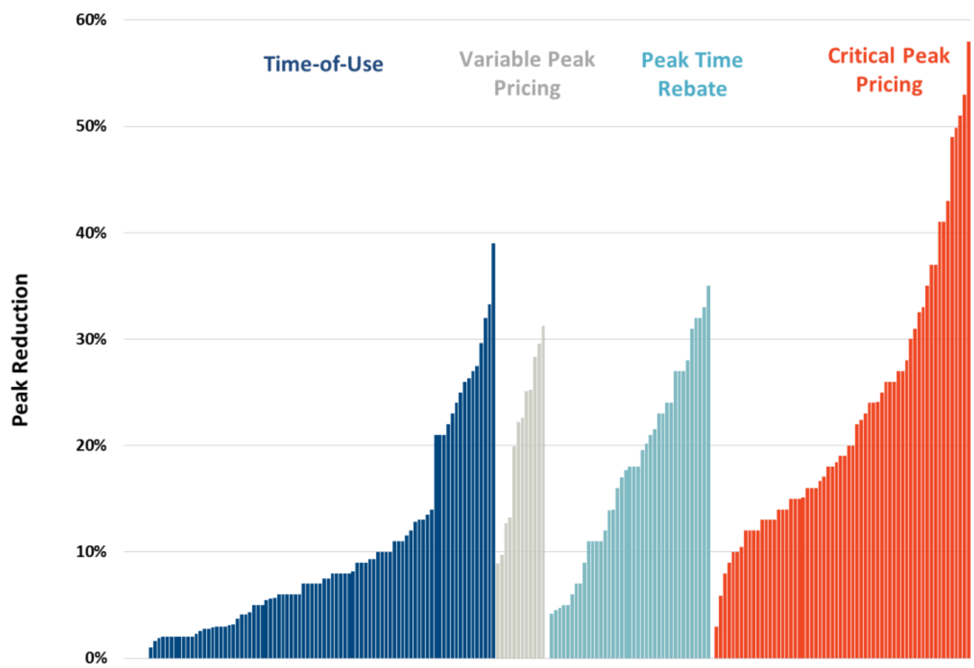
[23] HQD, *Rapport Final Du Projet Tarifaire Heure Juste*, Demande R-3740–2010, August 2010, page 30.

[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

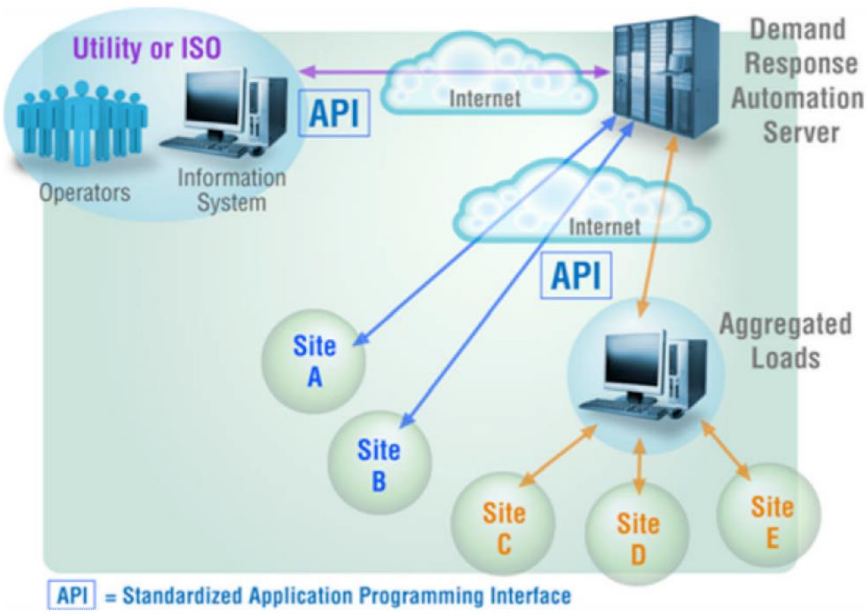
[34] http://aceee.org/sites/default/files/pdf/conferences/hwf/2017/Naleway_Session3A_HWF17_2.27.17.pdf

[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

[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

[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.

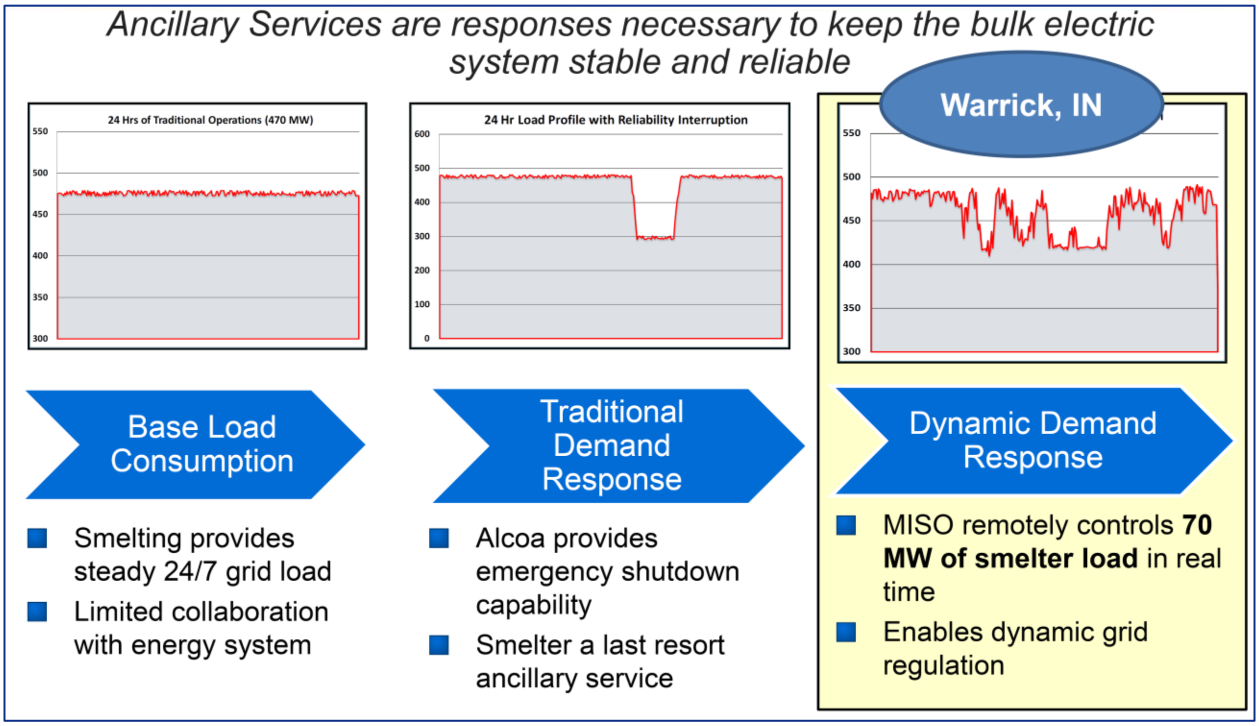
[47] http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

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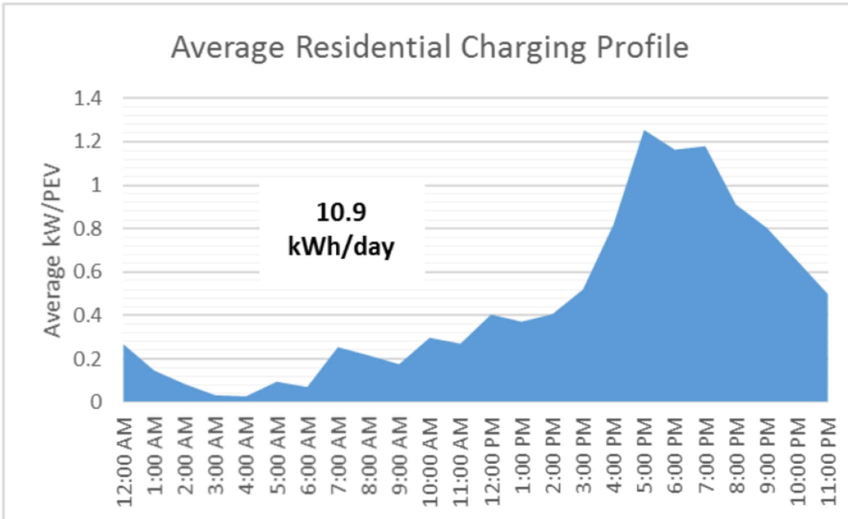
[51] http://products.greenmountainpower.com/product/tesla-powerwall/

[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

[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.

[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,

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[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.

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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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