The Value of Demand Response in a Hydro-Dominated Power Grid – The Example of Quebec, Canada

by

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A Thesis submitted to the Faculty of Graduate and Postdoctoral Affairs in partial fulfillment of the requirements for the degree of

Master of Arts

in

Sustainable Energy Policy and Engineering

Carleton University
Ottawa, Ontario

Abstract

Demand response (DR) entails programs that allow utilities to shift when electricity is being used. DR is of great interest in Quebec, as DR would increase the ability of the provincial utility to manage its domestic load. DR would also allow the provincial utility to improve the level of service to its export clients in neighbouring jurisdictions, such as New York.

This thesis explores a promising form of DR, namely direct load control of residential electric water heaters (EWH). EWH are ubiquitous in Quebec representing 94% of all domestic water heating appliances. I analysed the benefits that could be accrued by deploying a DR program, and contribute to the Public Policy literature by assessing the incremental revenues that can be achieved through the use of DR for price arbitrage between Quebec and New York. I estimated that up to 170,000 households would potentially participate, which would add 144.5 MW of capacity to the province's system, and would yield a net benefit of $35.9 million.

Acknowledgements

First, I would like to thank the three professors on my Thesis committee: Dr. Sujit Sur, Associate Professor, Sprott School of Business, Carleton University, Dr. Craig G. Merrett, Assistant Professor, Department of Mechanical and Aerospace Engineering, Carleton University, and Dr. Pierre-Olivier Pineau, Professor, Department of Management Sciences, HEC Montréal.

In addition, I would like to acknowledge the hard work done by all of the professors involved in the Sustainable Energy Policy and Engineering program, and in particular Stephan Schott, Associate Professor, and Alexandra Mallett, Assistant Professor, both at the School of Public Policy and Administration (SPPA), Carleton University, and Glen Toner, Professor at the SPPA. I am very thankful for their mentorship during the program.

To finish with, I am thankful to my wife, Chung, for her constant support and patience, and my two kids, Charlotte and Calvin, for being such well-behaved and fun children.

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List of Acronyms

ACE	area control error
AMI	advanced metering infrastructure
API	application programming interface
B/C ratio	benefit/cost ratio
CBA	cost-benefit analysis
CLPU	cold load pick up
CPP	critical peak pricing
CPUC	California Public Utility Commission
DADRP	day-ahead DR program
DAM	day-ahead market
DER	distributed energy resources
DOE	Department of Energy
DR	demand response
DSM	demand-side management
DRMS	demand response management system
EIA	Energy Information Administration
EWH	electric water heater
FERC	Federal Energy Regulatory Commission
GETS	Grid-enabled electric thermal storage
HQ	Hydro-Québec
HQD	Hydro-Québec Distribution
IEA	International Energy agency

IESO	Independent Electricity System Operator
kWh	kilowatt-hour
L	Litre
LAN	Local-area network
LBMP	location-based marginal prices
LOLP	loss of load probability
MEPS	minimum energy performance standard
MW	megawatt
MWh	megawatt-hour
NAPEE	National Action Plan for Energy Efficiency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	net present value
NRCan	Natural Resources Canada
NWH	normalized (electric) water heater
NYISO	New York Independent System Operator
OpenADR	Open Automated Demand Response
PAC	program administrator cost test
PCT	participant cost test
PRM	planning reserve margin
PV	photovoltaic
RAM	random-access memory
RF	radio frequency

RIM	rate-impact measure test
RTM	real-time market
RTP	real-time pricing
SCADA	Supervisory control and data acquisition
SCT	societal cost test
SPM	Standard Practice Manual
T&D	transmission and distribution
TCP/IP	Transmission Control Protocol/Internet Protocol
TCTR	*test du coût total en ressource* (French for TRC)
TDT	*tarification différenciée dans le temps* (French for TOU)
TOU	time-of-use
TP	*test du participant* (French for PCT)
TRC	total resource cost test
TWh	terawatt-hour
USNAP	Universal Smart Network Access Port
WACC	weighted-average cost of capital
Wh	watt-hour
Yr	year

Chapter 1. Introduction

The global rise of new renewable electric generation technology (wind, photovoltaic and solar in particular) is creating new challenges for power grid operators due to the variability inherent to these renewable electricity production technologies. This new source of variability has caused system operators to seek solutions to increase the level of *flexibility*. Flexibility is the ability for a power system operator to adjust either the demand or the supply so that they match each other. In the near future, markets will need solutions to make larger and quicker adjustments to cope with the new variable renewable energy resources as the penetration of new renewables continues to increase. Due to the economy's current decarbonisation effort, load flexibility is poised to increase in value going forward.

Quebec is a Canadian province located in the northeast of North America. It boasts a power system supplied with 99% of hydroelectricity, primarily from the large legacy hydro dams built in the 20th century in remote northern parts of the province. These northern reservoirs can store up to 176 TWh worth of potential energy in the form of water held upstream of the hydropower turbines. Quebec's hydro reservoirs have allowed its system operator to balance new renewables easily and at a lower cost than in most other power systems. This ability is of importance, as in the last twelve years (Haley, 2014, p. 782), Quebec's system operator had to integrate 2,857 MW worth of wind power production, representing 6.2% of capacity installed on Quebec's territory[1]. These numbers continue to increase every year.

Most neighbouring power markets, i.e. Ontario, New York State, and the other New England states and Eastern Canadian provinces, do not have access to such a flexible

[1] Including the Churchill Falls hydropower facility in Labrador, which despite not being on Québec's territory is treated as a domestic production unit from a system operation standpoint.

resource as Quebec does and are in need of its flexible solutions to cope with the variability of their renewable energy uptake. I will discuss the two solutions that are available to them: the first solution is leveraging their ability to manage their electricity demand (a concept also known as *demand response*) and the second, increasing the level of electricity trade with Quebec. More specifically, I will explore the possibility of improving the ability to manage demand *in Quebec,* which will enable the selling of this additional flexibility to those who need it *outside of Quebec*.

I will propose an innovative approach to estimate the monetary benefits of demand response (DR) in Quebec. The main innovation explored through my thesis is the use of DR for economic gain maximization purposes, known as "*economic dispatch"*, in addition to the traditional use of DR as a way to curtail the load during peak demand period. This innovative approach will use inter-market wholesale electricity prices to make DR dispatch decisions, thereby making use of arbitrage, rather than domestic market price or marginal cost of production.

The approach will be centered on a specific type of DR program, namely direct load control of residential electric water heaters (EWH). However, the approach could also apply to other thermostatically-controlled loads in the residential sector such as space heating, space cooling, and refrigeration. Furthermore, even though many of the discussions will revolve around Quebec's power system, these discussions also apply to any power system endowed with a great degree of flexibility that is located next to other power systems with fewer flexibility options.

I will combine facets of many disciplines, namely engineering, policy, economics and business. I start by explaining the rationale that led to selecting a specific type of flexibility

solution in Quebec in Section 1.1 to Section 1.4, then present a technology review of direct load control of EWH in Chapter 2. Next, Chapter 3 will elaborate on an analysis of the current market structure and political landscape that led to choosing the proposed valuation approach, followed by a quantitative valuation of DR in Chapter 4. Finally, Chapter 5 and 6 will discuss market potential and cost-benefit considerations.

1.1 Introduction to Demand Response and Direct Load Control

DR entails programs, products and electricity tariffs that alter the shape of the electricity load curve of the power system for a given control area. DR is one category of solutions that pertain to demand-side management (DSM), a broader category of solutions that entail acting on or influencing energy demand. Other categories under the DSM umbrella typically include energy conservation or energy efficiency and fuel switching programs. DR focuses on influencing *when* power is being used, where energy conservation focuses on reducing the overall amount of energy being used.

DR can take many forms; and, each form may be designed to address a number of issues. For example, it can shorten peaks in the load curve of the control area, fill up a valley, slow down an up- or a down-ramp, and/or dampen oscillations (FSC, 2014). To start with, Quebec needs DR because the main electric utility in Quebec, Hydro-Quebec (HQ), has to cope with a peak demand that is increasing year after year. HQ forecasts needing more production capacity by the winter of 2018 (HQD, 2013, p. 28). I further postulate that to peak shedding, Quebec could also use DR to maximize economic gains from electricity exports through exercising better control over domestic demand.

DR can be either *active* or *passive*. For the most part, passive DR consists of electricity tariff designs (e.g. peak pricing or time-of-use pricing) that indirectly results in electricity

end-users altering their usage patterns, which in turn create the desired outcome on the aggregated load. *Active* DR involves a triggering from an entity (most likely the system operator) to cause the alteration. Direct load control (DLC) is a form of active DR. DLC entails a power system operator remotely triggering either disconnection or change in the control parameters of electric appliances located in the premises of the electric utilities' clients. System operators issue control commands communicated from a central location to the electric appliances, and then executed by control hardware installed inside the premises. The load alteration is caused by switching these pieces of equipment OFF or ON (i.e. disconnection/reconnection) or by changing control parameters, such as the temperature set point.

1.2 Rationale for Demand Response in Quebec

DR should be of great interest to HQ and its owner, the government of Quebec, because DR would increase ability of HQ to manage its domestic load. Firstly, and the primary focus of this research, DR would allow HQ to offer a higher level of service to its prospective clients in neighbouring jurisdictions, to whom it sells electricity. Secondly, Quebec will soon be struggling with a capacity shortage (as suggested in the earlier section) and DR could alleviate that shortage by providing the ability to shorten the winter peak demand.

Increasing HQ competitiveness on export markets is critical to HQ's financial performance because the utility disposes of a considerable amount of electric energy available for export, about 26.6 TWh in 2014 (HQ, 2015b). HQ has direct interties with Ontario, the Maritime Provinces, as well as New York and New England states. New York and the New England States have historically been the "traditional markets" for Quebec's

hydroelectricity (Dufresne, 2015). The current amount of electricity available for export is a result of continued investment in different power technologies over the past decade (wind, small and large hydro, biomass).

The Quebec mainstream media have framed electricity exports as an electricity "surplus" by, which is reiterated by the national media outlets. The word "surplus" was first used by Lanoue and Mousseau (2014) in their review of the Quebec's energy sector, which was commissioned by the provincial government. Whether or not this energy is surplus will depend on Quebec's ability to market its product to its traditional markets. In any case, that electricity can be sold through existing interties, optimally by selling it at the highest market price in the exterior markets.

Two key aspects are hindering the competitiveness of HQ in these markets. The first challenge is HQ's mandate, which is to meet domestic electricity demand regardless of exterior market prices. The second challenge is that Quebec domestic demand exceeds HQ's generating capacity during brief periods of time in the winter. Not only does this mean that HQ has the obligation to procure more electricity production capacity for its domestic market, which is in itself costly but even more so because HQ has to purchase electricity in the dead of winter when wholesale market prices in exterior markets are generally high. Moreover, the priority given to domestic load means that HQ it is incurring lost opportunity for selling electricity during other periods of the year when wholesale electricity prices spike in other markets. HQ presently cannot take advantage of these opportunities because it must prioritize supplying its domestic clients, at a price lower than market value.

The future looks bright for electricity exports to the United States. New England, for instance, needs to find long-term electricity supply solutions (e.g. new natural gas pipelines and gas-fired power plants in New England) and is increasingly looking at Canadian hydroelectricity as an viable and acceptable option (Dufresne, 2015). A new 1,000-MW transmission line between Montréal and the New York metro area is in an advanced stage of development (Champlain Hudson Power Express, 2015). In addition, all exterior markets have increasing needs in system load flexibility (i.e. the ability to ramp electricity production up and down quicker and at a greater frequency) because they are adding a large amount of additional variable renewable resources to their power system. This is a trend that is likely to continue; and, therefore it will increasingly reflect on wholesale market prices by pushing up prices when generation from new renewable suddenly goes down. DR could help HQ make the most of these business opportunities, while contributing to dampening the price in exterior markets by altering the supply and demand market equilibrium.

1.3 Rationale for Residential Direct Load Control

Among all DR options, the process that led to selecting residential DLC in Quebec was a process of elimination. To start with, any form of passive DR is not an attractive avenue in Quebec because both the utility and the public have shown little appetite for a shift toward time-sensitive electricity prices. In the recent past, HQ has conducted peak pricing pilot projects in a number of municipalities (HQD, 2010). Results in terms of load reduction during critical peak times have not been sufficient for the utility to ask for a tariff structure revision (Régie de l'énergie, 2011) The utility publicly refused to back a shift

toward a time-sensitive pricing approach, i.e. real-time pricing, peak pricing or time-of-use pricing[2], in the short or medium term (Grammond, 2012).

In its latest rate application, HQ laid out in details why it decided not to follow through with peak pricing. HQ gave two main reasons for its reluctance to adopt a time-sensitive tariff structure. Firstly, HQ lists the small measured impact from such a change, which is a claim that is substantiated by the results of the pilot project. Secondly, HQ explained that peak pricing would create "winners among those who will not be making any efforts, and losers among those who will make efforts to react to price signals"[3] (HQD, 2015f, p. 14). This phenomenon is exacerbated by a great degree of sensitivity of Quebec voters with regard to any perceived tampering with residential electricity prices. This high degree of sensitivity is due to historical context, its status as a crown corporation and to the existence of a number of vocal advocates for low-income electricity users and for consumer rights who advocate keeping electricity bills as low as possible. Any change in the tariff structure would be framed as an attempt to increase the tariffs and low-income advocates would be quick to depict their constituents as "losers who are defenseless against price signals". Political sensitivity around electricity tariff in Quebec was explored extensively and developed by a policy paper by Pineau (2012). Because of the above, passive DR using price signals is a political minefield in Quebec, and has a low probability of implementation in the short and medium term.

I am not taking side in my Thesis on which one between TOU or DLC is the "best" solution to curtail peak demand in Quebec, and which one is the second-best option. "Best"

[2] In French time-of-use pricing is: tarification différentiée dans le temps (TDT).

[3] HQ wrote in French: "Il est également à noter que [la tarification différentiée dans le temps] fait inévitablement des gagnants malgré l'absence d'efforts et des perdants malgré leurs efforts en réaction au signal de prix".

can be defined in many ways and both approaches have benefits and drawbacks. DLC, however, appears to be the most likely and most practical approach in the short and medium term and do not preclude from adding TOU (or critical peak pricing) in the long term.

Active DR in the residential sector is a policy area that was not explored in Quebec as much as other options. An untapped potential lies within. HQ already has interruptible rates, a form of active DR, for its larger customers, thereby a portion of the DR potential in the non-residential sector is already being utilized. Quebec has not launched any DLC in the residential sector until recently, despite the fact that residential DLC program are ubiquitous elsewhere in North America. For example in the United States, the 2011 FERC survey of DR programs inventoried 200 active DR program programs and showed that the residential sector is where DLC was most used (FERC, 2011).

HQ is currently in the process of deploying its new advanced metering infrastructure (AMI), consisting of residential smart meters, communication infrastructure, data acquisition and data treatment ware, throughout the province. HQ's new advanced metering infrastructure will be an enabler to DLC. The lack of AMI was as a technological challenge (although multiple solutions to the lack of AMI do exist, as discussed in Appendix A). With the roll out of the new province-wide AMI, the lack of an appropriate communication solution is no longer an impediment to the implementation of an active DR system like DLC of residential EHW.

In summary, constraints that prevent the launch of residential DLC in Quebec do not reside in the lack of potential or of technological challenges anymore. It is the political and institutional challenges that have slowed down the adoption of DLC strategies, as well as

the inability to make a proper business case for adoption of DLC. I propose to tackle the latter challenge in hope that the results can also help gaining political support.

1.4 Rationale for Selecting Electric Water Heaters for DLC

In the residential sector, DLC is particularly suitable for thermostatically-controlled appliances like air-conditioning units, freezers and electric water heaters (EWH). Thermostatically-controlled appliances are amenable to DLC because they store thermal energy for users to dispose of when needed. The thermostatically-controlled appliances can be disconnected for periods of time without the usage being significantly impacted, unlike lighting fixtures or TV sets which usually require power for instantaneous use.

Domestic water heating is a considerable electricity usage in Quebec, and it is higher than in any other province. Penetration of EWH in Quebec is 94% (NRCan, 2010), as opposed to natural gas- or oil-fired water heaters.. Quebec is a winter peaking-jurisdiction because of the high penetration of both EWH and electric space heating. Quebec's domestic system load has two peaks: a morning peak between 7:00 and 11:00, and an evening peak from 17:00 and 21:00. Both coincide with the peak load of residential electric water because winter is when water feeding the EWH is the coldest, and because the morning and evening peak is when most water is being used (Laperrière, 2008; Moreau, 2011).

DLC targeting EWH is promising in Quebec for the following reasons: the intrinsic thermal storage capacity of hot water tanks, the coincidence of the EWH load with the system peaks, and because DLC can be triggered regardless of the season and exterior temperature unlike DLC of heating or cooling equipment (Shaad, Momeni, Diduch, Kaye, & Chang, 2012). EWH are usually out of people's sight because EWH tend to be hidden

in a basement or a closet, and people usually do not interact with their water heater on a regular basis like they would interact with their refrigerator or their dishwasher.

On July 31, 2015, in its annual 2016-2017 rate application, HQ publically disclosed its intention to launch a DLC program targeting EWH. HQ stated that the program is to be adopted on a voluntary basis. HQ is to take the program to market, communicate the program offerings and enroll participants (households), install control equipment at no cost to participants, and then pay participants an incentive to attract them and keep them into the program. Participants will be offered a temporary "opt-out" option, which mean that they can request their EWH not to be remotely controlled for a certain short period (one day, for instance). The program was to be launched in the next few months after the rate application. HQ anticipates that 100,000 participants are to enroll in the program in the first year of operation (HQD, 2015e, p. 17). A total of $34 million was budgeted in capital expenditures and $4 million in operational expenditures during the first two year of deployment of the program (HQD, 2015e, p. 31). The announcement was made three months after the start of the work that led to my thesis, indicating the timeliness, relevance and urgency of this topic. My thesis can thereby be used not only to make a constructive criticism of the program design and the valuation performed by the utility, but also as an independent analysis and communication medium of the program.

Chapter 2. Technology Review

Chapter 2 describes the analytics as well as the hardware and software that are involved in direct load control of electric water heater. In particular, Section 2.1 will describe EWH in Quebec from a thermodynamic and a control standpoint as well as the resulting electricity demand, Section 2.2 will present the approach to schedule DLC, the main challenges that controlling EWH entail, and the approaches used to address these challenges. Section 2.3 will describe the equipment involved in operationalizing DLC.

2.1. Residential EWH Tanks

Section 2.1 presents the appliances supplying domestic hot water to Quebec's dwellings and then explains how power demand profiles for this pool of appliances ought to been estimated.

Hot Water Tanks

Domestic hot water in Quebec is largely supplied by two types of EWH tanks built by a handful of local manufacturers, among them Giant, Rheem, Whirlpool, Moffat and GSW. Giant is the dominate brand because it is distributed in the four largest hardware retail store chains in the province[4].

EWH tanks are cylindrical insulated tanks containing two heating elements, each of which is coupled with its own thermostat. The tanks are made of a steel hull designed to sustain water pressure up to 689 kPa. The exterior of the hull is covered with insulation materials: either polyurethane foam or fiberglass. The interior of the hull is covered by a

[4] Based on the survey of the websites of the nine dominating retail chains: Rona, Réno Dépôt, Canac Marquis, Groupe BMR, Home Depot, Lowe's Home Improvement, Home Hardware, Costco, and Canadian Tire. The four first chains, which are the largest hardware store chains in Québec, carry Giant water heaters. Home Depot, Lowe Hardware, and Home Hardware carry Rheem, Whirlpool and GSW respectively. Costco carries Rheem. Canadian Tire carries Moffat.

coating to prevent rust (Laperrière, 2008; S. Wong, Muneer, Nazir, & Prieur, 2013). The main components of a typical EWH tank are illustrated in Illustration 1.

There are two main tank sizes in Quebec: about 60% of residential electricity customers have a 270-litre tank with two 4.5-kW heating elements, and the remainder have a 180-litre tank with two 3.0-kW elements (S. Wong et al., 2013, p. 3). Tank-less water heaters, popular in other jurisdictions, are rare in Quebec due to climatic limitations; i.e. the water inlet temperature can approach the freezing point in the winter. Tank-less water heaters, if they were used in Quebec, would need to be over-designed. The heating elements in a water tank do not need to be oversized because the water tank act as a buffer against cold water temperature.

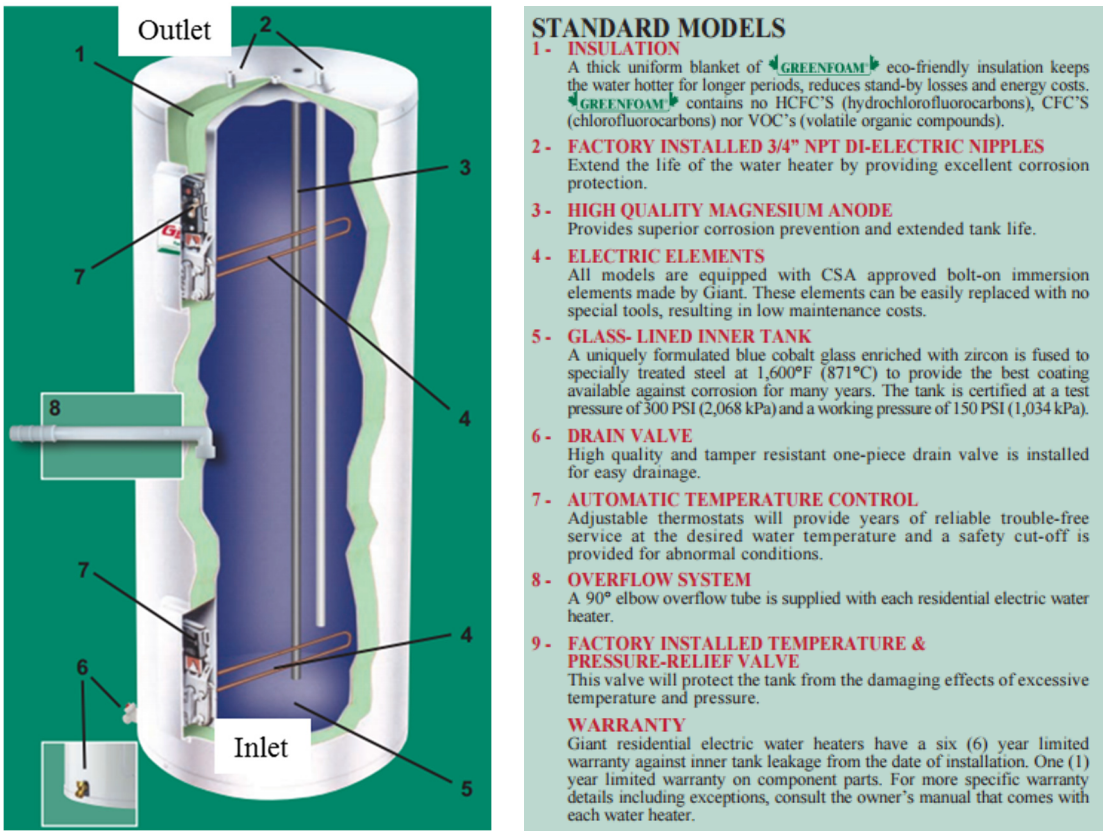


Illustration 1: Schematic of a Typical Electric Water Heater Tank
Source: adapted from Giant (2014)

Illustration 1 shows the two heating elements and thermostat assemblies: one at the bottom and one at the top. Both of them have a corresponding access door. The hot water outlet is on top of the tank and the cold water inlet may be at the top or bottom of the tank, but the water is nevertheless always mixed at the bottom (See Illustration 2). This, combined with the fact that hot water has a lower density than cold water, ensures that water will always be hotter at the top of the tank, near the water outlet, than at the bottom. This phenomenon is called stratification.

Stratification

Temperature stratification inside the EWH tanks is sought after by the manufacturers because it increases the amount of water that can be drawn from the tanks before a decrease in outlet temperature is felt by the users. Manufacturers have come with ways to decrease mixing between the vertical layers of water to increase stratification, such as bottom entries with specially-designed inlet nozzles or dividers inside the tanks. Most EWH, however, are still top-entry tanks as shown in Illustration 2. Due to stratification, the gradient between outlet and average water temperature is 23º on average in the winter (50ºC versus 27ºC), and 17º in the summer for the 270-litre EWH (50ºC versus 33ºC). The seasonal difference is due to the water inlet temperature, which is about 1.5ºC in the winter and 23ºC in the summer. Colder inlet temperature in the winter increases the stratification phenomenon. Temperature gradient decreases as tank size decreases (S. Wong et al., 2013, p. 11).

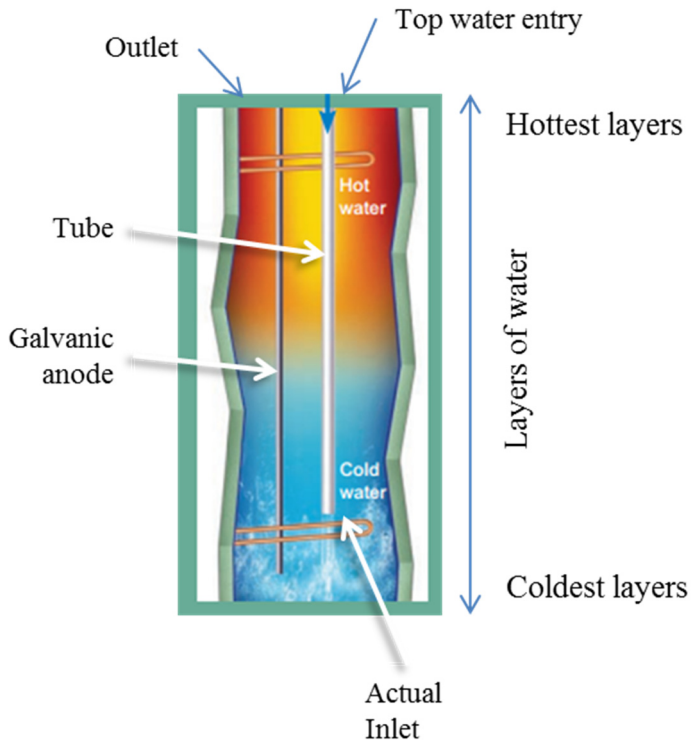


Illustration 2: Schematic of a Stratification for Top-Entry EHW
Source: adapted from Giant (2014)

Accounting for stratification is now the standard practice for EHW energy modeling. The majority of latter authors, such as Ruiz et al (2009), Cruickshank (2009), Kondoh et al (2011), Moreau (2011), Saker et al (2011) and Ayoub (2013), Wong et al. (2013) and Ruelens et al. (2014), all used some form of layering in their thermodynamic model. Properly accounting for stratification increases the resolution level of the modeling results regarding whether DR events (of any type) have influence on the outlet temperature and thereby on users' comfort.

Control Sequence

EWH are controlled by two thermostats: the first one controls the top heating element and the second one controls the bottom heating element. The thermostats are fastened on the exterior of the steel hull beside the elements and sense the temperature through the hull.

The temperature is approximately 0.1ºC superior to the temperature sensed by the thermostat (Allard, Kummert, Bernier, & Moreau, 2011, p. 670).

Thermostats come from the factory with a 60ºC temperature set point. This setting is rarely changed and should not be changed because 60ºC is recommended to prevent the development of Legionella bacteria in the tank (Bartram, Chartier, Lee, Pond, & Surman-Lee, 2007). The thermostats' dead band length is approximately 10ºC, thus any temperature reading below the dead band (typically 60 ºC minus 10ºC or 50ºC) will turn the heating element ON, and any reading above the dead band (typically 60ºC) will shut the heating element OFF.

Water at 60ºC (or above) may cause skin burns, and this is why installers of new EWH are required by regulation to add a thermostatic-mixing valve, downstream of the outlet of the tank, that blends some cold water into the hot water to cool down the water supplied to the main bathrooms of the house. Thermostatic-mixing valves, however, are not found in all houses because older houses were built prior to the regulation and because a few new houses might have escaped compliance. Regardless, a temperature up to 60ºC is allowed in Quebec for water that supplies secondary bathrooms, dishwashers and washing machines because a number of water usages, such as laundry, do require water at 60ºC. Not all houses will have a thermostatic-mixing valve, so any DLC strategy involving over-heating tank water above 60ºC would require significant plumbing retrofit to ensure occupant safety.

The control sequence of a typical EWH goes as follow: in the early morning the EWH has had all night to heat the content of the tank and thus most of water is at the temperature set point (typically 60ºC). When hot water is withdrawn from the top of the tank, cold water

will flow in the bottom of the tank and the lower layers of the tank will cool down. Soon, the temperature sensed by the lower thermostat will be lower than its dead band, and the lower heating element will turn ON. If the household continues consuming hot water, the upper water layer of the tank will cool down enough so that the temperature sensed by the upper thermostat will be below its dead band. The upper thermostat will then cut OFF the lower heating element and turn ON the upper heating element in an attempt to heat up the upper water, closer to the temperature outlet thereby both heating elements can never be ON at the same time. If hot water is used until the tank is "depleted", then the temperature of the uppermost layers of the tanks will cool down below the dead band (typically 50ºC) and so will the outlet temperature. From that moment, this household is deemed to be "lacking hot water". If hot water stops being drawn from the tank, the upper heating element will stay ON until the surrounding water temperature reaches the set point. Then, the lower heating element will pick up and continue until the set point temperature is fully recovered in the tank.

The lower heating element is the one element that is turned ON the most often because large water withdrawals that require the top element to be switched ON are a rarer occurrence than smaller withdrawals. Energy storage in EWH comes from stratification inside the tank or in other words energy storage comes from the temperature gradient between uppermost water layers near the outlet and the bottom layers near the inlet.

Single-EWH Energy Demand

A EWH uses electric energy to make up for two thermal energy flows: hot water being drawn from the tank to be used by the household, and heat loss through the tank's insulation into the indoor air (EWH are typically installed indoor). Total energy consumption of any

EWH is thus a function of inlet water temperature that varies considerably on an annual basis, hot water usage in each household, indoor ambient air temperature, and technical characteristics of the EWH themselves such as tank volume, heating element power rating, thermal resistance of the insulation, and thermostatic set points and dead band length.

Standby heat loss is relatively constant because it is caused by a stable temperature gradient between the tank water temperature (most of the time between 50ºC and 60ºC) and the house ambient temperature (typically stable and at 20ºC). Energy use through standby losses is smaller and more constant than energy use due to hot water usage.

Canada's latest minimal energy performance standard (MEPS) for EWH, which was set in 2008, limits standby heat loss to 2.76 kWh and 2.33 kWh per day for a 270- and a 180-L tank respectively (Lloyd & Ryan, 2008, fig. 4). These numbers are upper bounds because the MEPS compliance testing laboratory procedures are such that no water is withdrawn from the tanks during the tests. In real life, water will be withdrawn which will lower the average temperature of the tank thus lowering the actual level of standby losses. The 1995 version of the Canadian MEPS allowed heat losses that were 22% higher (Laperrière, 2008, p. 35). Few EWH installed prior to the 1995 MEPS remain in the market since EWH have a half-life of 18 years in Quebec (Laperrière, 2008, p. 51) and their number is dwindling.

Quebec's supply of EWH is homogeneous; i.e. the tanks' technical characteristics do not vary significantly from one household to the other. Consequently, by the process of elimination there are only two main independent drivers to a EWH energy use in Quebec: household hot water usage and the water inlet temperature.

Household hot water usage in Quebec has a median of 173 litres[5] of hot water per day, according to a measurement campaign by Laperrière (2008) of the Laboratoire des technologies de l'énergie of Hydro-Quebec. Laperrière had a sample size of 72 households and monitored water outlet flows as well as instantaneous power draw with a 5-minute data logging interval for 160 consecutive winter days. In addition, Laperrière's data showed a clear correlation between water usage and the number of household members. According to Laperrière's data, about 60 litres per day per person are used by Quebec's households. The median electricity use, according to Laperrière's data, was 12.3 kWh per EWH per day[6]. Thereby, approximately 10.0 kWh worth of electricity per day is needed to supply hot water to the household and 2.3 kWh is needed to compensate for standby losses or 81% and 19% respectively.

Water inlet temperature follows a predictable annual cycle. The inlet temperature dips to 1.5ºC in the depth of winter in Montréal and then peaks at 23ºC in the summer (Laperrière, 2008; S. Wong et al., 2013, p. 11).

The instantaneous power drawn by each individual EWH follows an ON and OFF pattern. Either one of the heating elements is ON and draws its rated power (4.5 kW for a 270-L tank) or else the power draw is nil. By design, the rate of thermal energy leaving the tank during each withdrawal event is superior to the capacity of the heating elements. The concept is presented in Illustration 3.

[5] The first quintile upper boundary is at 118 l/day and the fifth quintile lower boundary is at 258 l/day.
[6] The first quintile upper boundary is at 9.0 kWh/day and the fifth quintile lower boundary is at 16.8 kWh/day.

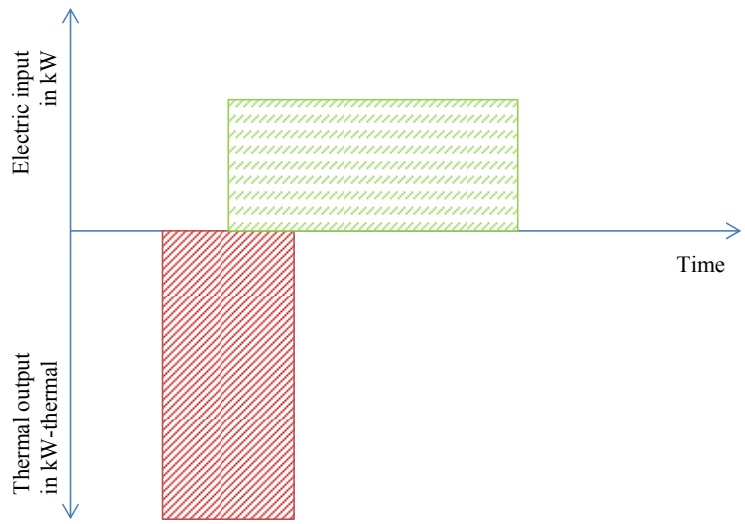


Illustration 3: Thermal and Electrical Energy Consumption Profiles
Source: adapted from Kondoh (2011)

In both Illustration 3, the rate of thermal energy leaving the tank is shown below the "time" axis, and the heating element power draw when it is subsequently turned ON is shown above the "time" axis. Thermal energy exiting the tank is represented by the hatched area and electric energy entering the tank is represented by the dotted area. Conversion rate of electric energy into thermal energy through the heating elements inside the tank is 100%. The time it takes to restore the level of thermal energy in the tank is longer than the time it took to remove thermal energy in the first place. The lag experienced between the water withdrawal and restoration of the energy level stored in the tank is shown in Illustration 4.

Illustration 4 presents thermodynamic modeling results for one EWH using a typical water usage pattern. The EWH is turned ON each time water is drawn, after a short delay the lower thermostat will sense the temperature drop and turn the bottom heating element ON, which will raise the temperature until it reaches its set point.

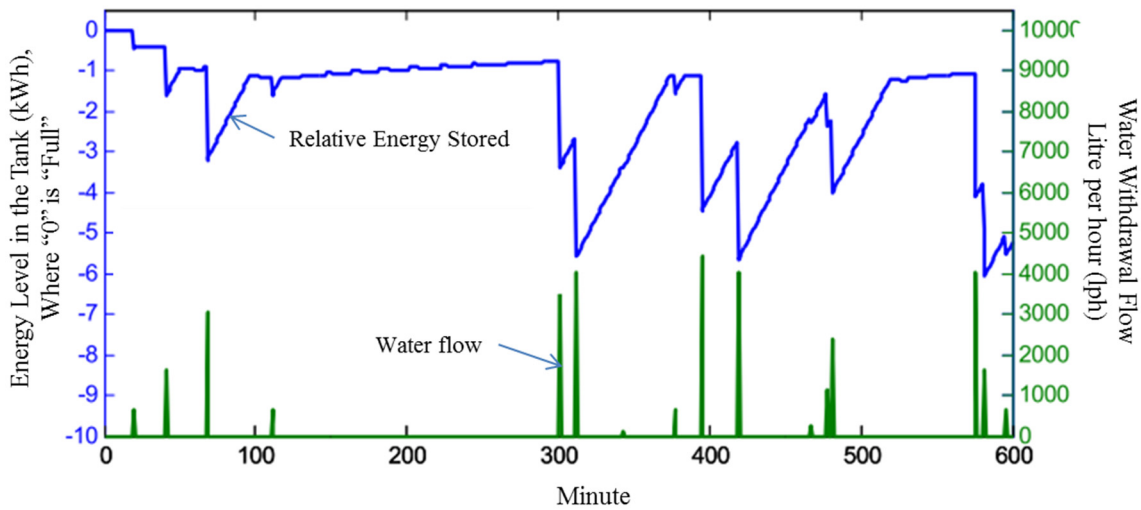


Illustration 4: Energy Storage Profile Inside a 270-litre EWH over 10 Hours
Source: adapted from S. Wong et al. (2013), fig. 2.6

In Illustration 4, the green line (below) follows the water withdrawal events, in litre per hour. The blue line (above) shows the thermal energy storage level inside the tank, where the "0" level indicates the tank thermal storages is fully replenished. Every withdrawal triggers a sharp decline in thermal energy level, and then the tank's heating element seeks to catch up. However, the slope of the replenishments, which is limited by the heating element power rating, is not as steep as the declines.

When viewed at a household level, each EWH has a load profile made of scattered ON and OFF events throughout the day and a peak load equivalent to their power rating. However, the provincial power system sees an aggregated load profile of thousands of EWH all connected to the grid. The load profile of a combination of all EWH as seen by the power system is named the EWH's "diversified" load profile.

Diversified Load

As per Moreau's definition (2011), the diversified electrical demand of EWHs represent the average load recorded by the grid for a population of EWHs, considering the

diversity of water withdrawal profiles. Illustration 5 shows what happens when building a diversified load curve from multiple individual EWH load curve. The diversified load curve is the aggregate operating state, which means that, physically, it represents the average fraction of EWH in the ON state. Illustration 5 is the diversified load profile in Ontario. Each of the five lines represents a different population size of *normalized* water heaters (NWHs), i.e. the total aggregated profile divided by the number of EWH.

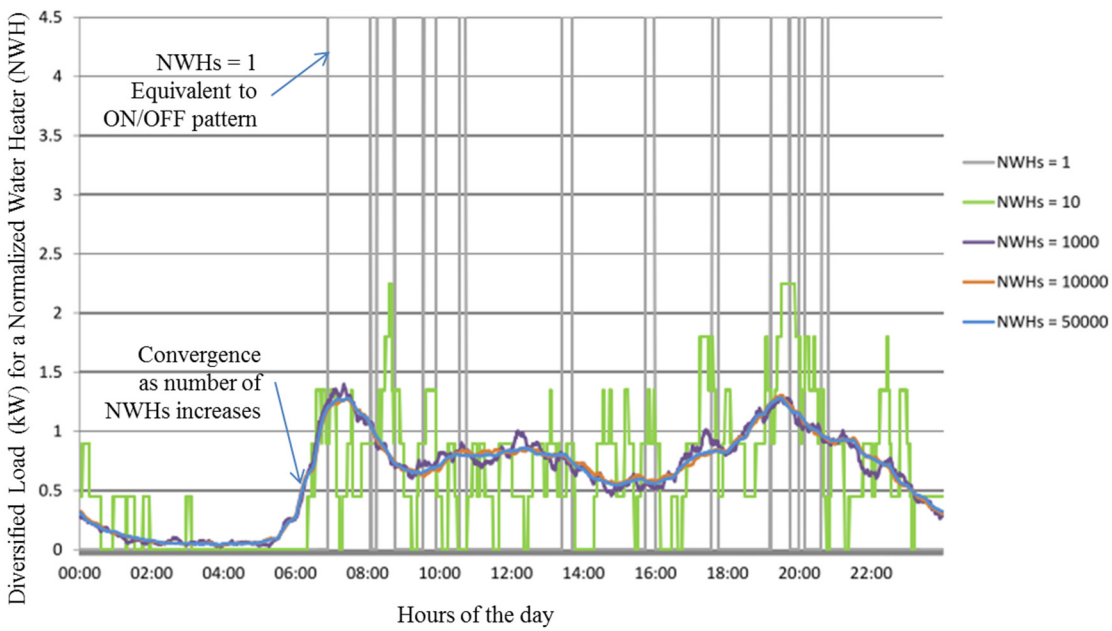


Illustration 5: Diversified Electrical Profile for Select Population in Ontario
Source: adapted from S. Wong et al. (2013), fig. 3.5

The profile for a population size of 1 NWHs, in Illustration 5, is a seemingly random pattern of ON and OFF states. It peaks at 4.5 kW, which is the power rating of its heating element. As the population size grows, with NWHs = 10 and 1,000, a pattern shapes up around a morning peak and an evening peak, but the profile is still volatile due to the small number of statistical trials. The profile for the two largest population sizes, NWHs = 10,000 and 50,000, is smoother and closely matches one another, which is a sign of convergence and is a result of the larger number of statistical trials.

Illustration 5 is illustrative of what happens to NWHs' peak for larger populations. The normalized peak decreases as the population increases, and converges toward a morning peak and an afternoon peak. Illustration 5 also demonstrates that the demand profile for each EWH has a statistical bias toward certain hours of the day during which the water withdrawal events are most likely to occur. These results make intuitive sense because Canadian business hours, lifestyle habits and social conventions have influence over when people use hot water.

The determination of the diversified load from large population of EHW is one key challenge that has been tackled since the early days of direct load control of EWH and solved through multiple means.

The first academic papers on the matter all presented **top down approaches** to determining the diversified load such as the approach suggested by Rau & Graham (1979), Hasting (1980), Lee & Wilkins (1983), Bischke & Sella (1985) and Orphelin & Adnot (1999). The first and last of the five papers presented a simplified algebraic representation of the diversified load curve. For instance, Rau & Graham modeled the diversified load curve as a convex hyperbolic function peaking at around 6 p.m. Hastings, Lee & Wilkins and Bischke & Sella used an empirical approach and developed diversified load curves using the results of vast EWH load measurement campaigns.

Gustafson et al. (1993), Laurent & Malhame (1994), van Tonder & Lane (1996), Kondow & al. (2011), Saker et al. (2011) and many others all used **bottom-up approaches** to determine the diversified load curve. A bottom-up approach starts with the modeling of "elemental" EWH (or individual EWH) and then builds the diversified load curve through aggregation. Each elemental EWH is modeled through a set of thermodynamic and control

equations. The total load of a large pool of elemental models is expected to be an accurate forecast of the actual total load of a large pool of real EWH. Now that computing power is less of a limitation, most contemporary researchers use bottom up approaches because it increase the level of granularity of the results and allows to tests all sorts of theoretical control strategies – as laid out in Section 2.1.

Laurent & Malhame (1994), professors at École Polytechnique in Montréal, perfected the bottom-up approach. The methodology that they developed is based on an interval simulation in which the operation of each one EWH is run through a daily probability function of hot water usage. At each interval (time increment), the state (ON or OFF) of the current interval is determined considering the state during the previous interval, the thermal energy stored at the end of the previous interval, and the hot water drawn from the tank during the current interval. Hot water draw is a random function with a certain probability attributed for each interval. The likeliness of hot water to be drawn at each interval is given by the "probability density function" of hot water usage. Laurent & Malhame had to build such probability density function out of a set of assumptions on hot water usage thorough the day since they did not have any empirical data on water usage to feed their model. This lack of real data was to be solved later when Laperrière (2008) and then Moreau (2011), both researchers at Laboratoire des technologies de l'énergie in Shawinigan, Quebec, carried out extensive measurement campaigns including interval metering of both hot water flow and EWH power draw in real households. Laperrière's sample size was 72 households during two winters (2 x 160 days). Moreau's sample size was 52 households during one winter (160 days). Both were able to build hourly water usage probability density functions using typical households' data. Based on the water

usage functions and using Laurent & Malhame's bottom-up methodology, Moreau was able to build a diversified load curve for Quebec. The load curve that he obtained matched the results he obtained from aggregating individual EWH load profiles (See Illustration 11 on page 35).

2.2 Direct Load Control of EWH

This Section discusses the DLC solutions and a number of design options of a DLC program as found in academic literature.

For years, utilities and scholars have sought ways to apply DLC on domestic water heaters while mitigating the effect of cold load pick up (CLPU), also known as the "rebound effect", the "snap back" or the "payback effect". CLPU occurs immediately after a DR event (e.g. a switching signal) when the pool of EWH targeted by the event seeks to restore its level of thermal energy. It may help to remember that DLC can only shift the load to another time in the day and is not meant to lower cumulative energy use. DLC could be used to achieve many goals (as further discussed in Section 2.1), but energy conservation is not one of them. CLPU, if untamed, can be an issue because the diversified load immediately after a DR event is larger than both the diversified load that was controlled in the first place, and the diversified load that would have occurred at the same hour if no DR event had ever been triggered.

DR performance is thereby limited by two constraints. Firstly, DR program analysts seek to mitigate of the negative effects of CLPU, such as the creation of a second power system peak for example. Secondly, program analysts want to minimize the occurrence of "lack of hot water" events in households because these are an inconvenience to the hot water users. Periods when users are "lacking hot water" are defined as periods when the

outlet water temperature is below the dead band of the EWH (most of the time, below 50ºC). An optimal DLC routine is thereby one that maximizes the EWH load curtailment during the power system peak time (or the realization of any other goal(s)), paces the thermal energy recovery and allows it to ramp back up only when the system peak has lowered sufficiently, and at the same time ensures that the majority of EWH (if not all of them) are switched back ON in time so that the users never lack hot water.

Illustration 6 shows most of the topics that are discussed in Chapter 2 in relation with each other in the form of a flow chart.

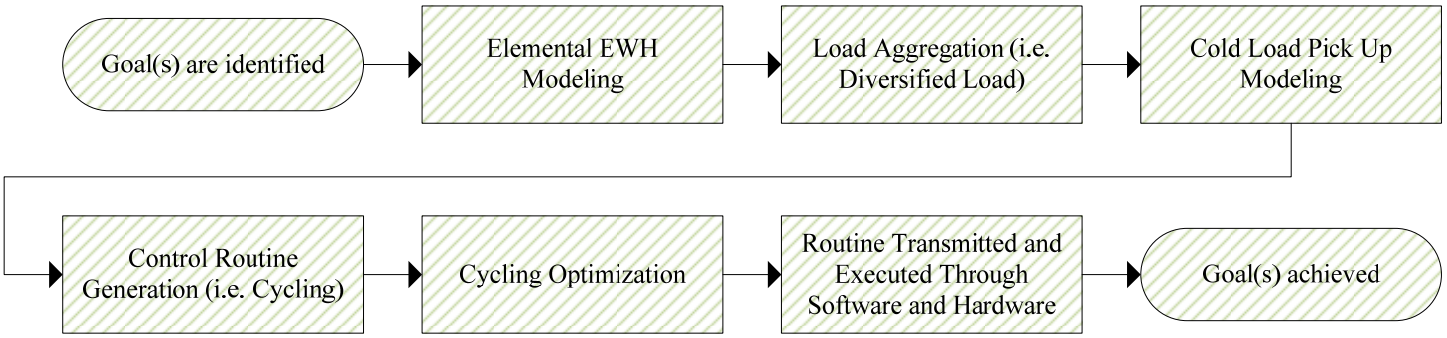


Illustration 6: Flow Chart of an *Ideal* Approach to Direct Load Control Dispatch

The following pages delineate the analytics required to determine the most appropriate DR routine. Most DLC routines that manage to avoid CLPU and reduce the likeliness of lacking hot water use a grouping-and-staggering approach; i.e. the entire pool of EWHs enrolled in the DLC program are divided in a number of groups and then a sequence of control commands are sent to each individual group. The sequence of control commands sent to each group varies in type of control commands, timing, and duration (scheduling).

DLC Goals

The types of control commands vary according to the goal(s) that are expected to be achieved through DLC. The types of command include switching commands, thermostat set point adjustments, or voltage adjustments. The goals of DLC found in literature are listed in the first column of Table 1. The second column lists the types of control commands that are appropriate to achieve each goal.

Table 1: Goals of DLC and Types of Control Commands

Goal	Type(s) of Control Command	Citations
Power system peak shedding (or shifting) for system adequacy (reliability) reason and/or for economic reason (economic dispatch)	ON/OFF switching commands upstream of the EWH circuit *without* temperature reading	Rau & Graham (1979) Hastings (1980) Lee & Wilkins (1983) Bischke & Sella (1985) Cohen & Wang (1988) Gustafson et al. (1993) Laurent & Malhame (1994) Laurent et al. (1995) van Tonder & Lane (1996) Orphelin & Adnot (1999) Ericson (2009) Wong & Negnevitsky (2013)
	Switching commands upstream of the EWH circuit *with* tank water temperature reading	Moreau (2011)
	Thermostat setbacks (downward only)	Saker et al. (2011) Wong et al. (2013)

Goal	Type(s) of Control Command	Citations
Power system regulation (i.e. continuously bridging the gap between supply and demand, based on a near-instantaneous control signal)	ON/OFF switching commands, bypassing that of the EWH's thermostats, based on continuous temperature reading, and allowing overheating of water as required	Kondoh et al (2011) Vrettos & Andersson (2013)
	Voltage regulation, based on continuous temperature reading, and allowing overheating of water as required	Ayoub (2013)
Reduce cost of operating a EWH for the EWH's owners (Price-reactive DR enabling)	EWH with an embedded programmable logic controller handling learning optimization algorithms with temperature sensors and calling its own ON- and OFF-switching commands.	Al-jabery et al. (2014) Ruelens et al. (2014)
Up- and down-ramping ancillary services (e.g. spinning or non-spinning reserve) to absorb intermittent wind power generation	Thermostat set point adjustments (upward and downward), with temperature reading	Pourmousavi et al. (2014)

The majority of the authors listed in Table 1 have envisioned DLC as a way to shift load for system adequacy or economic purposes using a control switch installed upstream of the 120- or 240-V circuit that supplies the EWH. The control switch usually is installed by the utility at no cost to the participating households. All of the approaches other than the traditional control-switch approach used since the 1970s have one major drawback in common: they would require either the deployment of a new design of EWH or they would require extensive (and costly) retrofit of the existing EWH and of the households' plumbing. These approaches make them more challenging and, hence, less likely to be

pursued by utilities, system operators or their agents. Nevertheless, they are listed and explained below.

In the recent years, scholars, such as Saker et al. (2011) and Wong et al. (2013), published papers on approaches that involve temperature set point adjustments. The benefit of thermostat set point adjustments is to prevent the water temperature level decreasing below a certain threshold, thereby reducing the risk of lacking hot water, and allowing for the dampening of the CLPU because all of the high-usage EWH will have already switched ON by the time the DR event is over. The drawback is that the diversified load for the pool of heaters targeted by DR is not guaranteed to be nil during the DR event. At the start of the event, the sudden decrease of the set point will cause the majority of the EWH to switch OFF, but then during the event a number of heaters will start to switch back ON.

Ayoub (2013) suggested using voltage adjustments to modulate the throughput of the heating elements. If the pool of EWH targeted by the voltage adjustments was large enough, it would allow the system operator to do near-immediate upward and downward adjustments of the demand to make up for the intra-hour gap between the supply and the demand, which is an ancillary service referred to as "regulation". Since no heating element would be stopped, this approach would reduce the likeliness of users to lack hot water.

Two groups of authors, Al jabery et al. (2014) and Ruelens et al. (2014), have worked on the concept of "smart" EWH with embedded artificial intelligence, which would enable automatic price-reactive DR (or *indirect* DR). These smart appliances would react automatically to price signal sent by the utilities, for instance in the form of time-of-use pricing or real-time pricing. Each smart EWH would learn the hot water usage pattern that are typical to the household where it is installed and then schedule the switching of the

heating elements to minimize operation cost and reduce the likeliness of lacking hot water. In addition, its deployment would not require any jurisdictional-wide coordination or any centralized control system. The evolution of the market could occur from the bottom up rather than requiring a top-down implementation. The drawback is that this approach can only benefit the society (through an overall decline in electricity production cost) if electricity prices commensurate with the marginal cost of production. For instance, if prices are regulated and the utilities do not have a time-of-use pricing schedule, as it is the case for Hydro-Quebec, then the smart EWH approach would yield no result.

A number of scholars, such as Ayoub (2013) and Pourmousavi et al. (2014), have explored the idea of allowing the tank water temperature to rise above its set point (typically 60ºC) in order to provide "downward ramping" services to system operators. Downward ramping has been increasingly in need by operators who seek to accommodate for fast up-ramping of wind power generation. The system operators would benefit from being able to dump excess power generated by the wind turbines into the EWH for later use. Furthermore, allowing the temperature set point to be increased also enables "pre-heating" of the tank water, which would allow load shedding events to last longer without impacting hot water users. The drawback of such an approach, however, is that all EWH would need require a thermostatic mixing valve at their outlet to make sure that the water supplied to the household cannot cause skin burns, which would cause considerable costs in plumbing retrofit if this approach was deployed on a large scale.

Cold Load Pick Up

CLPU is a main limitation to DLC performance, thereby a firm grasp of the CLPU is critical to understanding the optimization algorithms found in the literature. CLPU arises

when the natural diversified load curve of a pool of EWH is disturbed by a DR event. All of the types of control commands introduced above in Table 1 can cause CLPU to some extent, although some less than others. The one type of command for which the CLPU is the most significant and most widely studied is for load switching; i.e. a momentary disconnection of the EWH. After a switching event, the system operator should expect to observe a surge in the diversified load because a large number of the EWH in the pool will seek to replenish their level of thermal storage by switching back ON simultaneously. The magnitude of the surge depends on the number of EWH that will need to switch back ON immediately after reconnection, which is a function of the cumulated hot water usage during the switching event, as illustrated in Illustration 7.

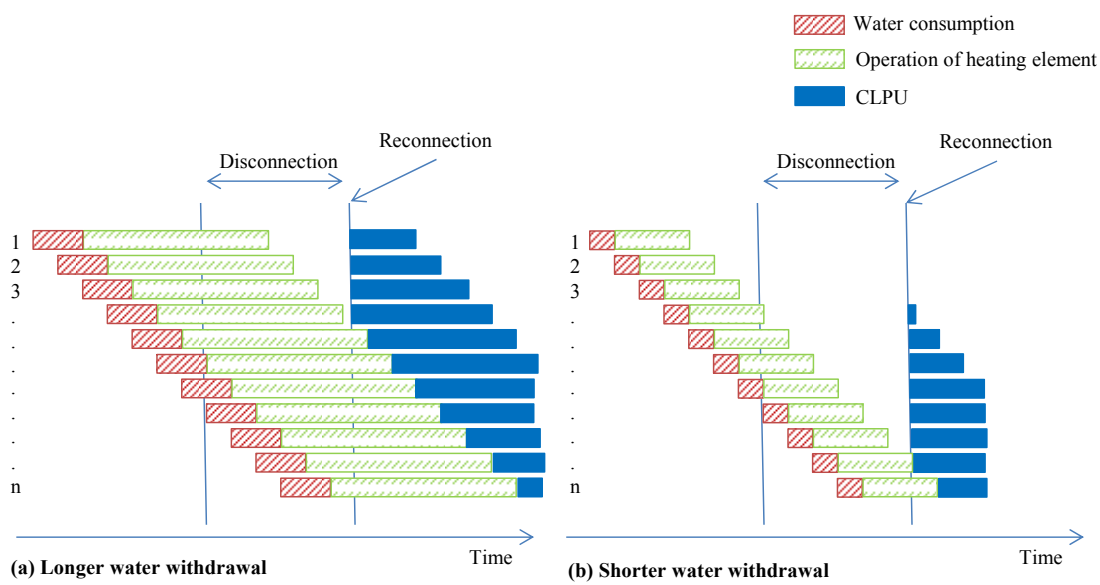
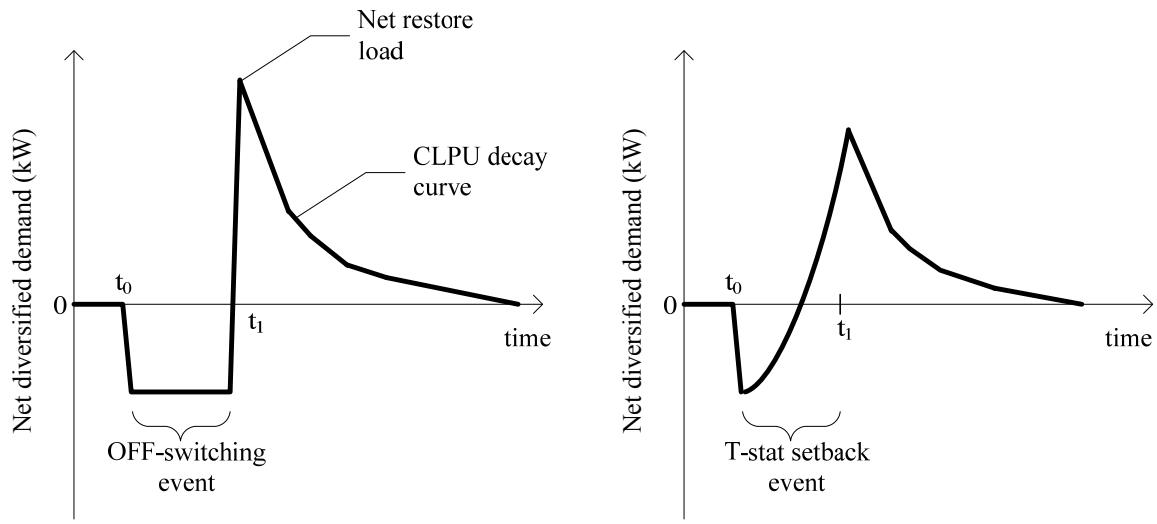


Illustration 7: Energy Recovering of EWH with and without Disconnections
Source: adapted from Ericson (2009)

Illustration 7(a) shows a pool of EWH (1 to n) with a large water draw before, during and toward the end of the OFF-switching event (from t_0 to t_1). All of the high-use EWH require an immediate power draw. Illustration 7(b) shows a pool of EWH (1 to n) with one

small water draw. Few of them will switch back ON after the event, and when they do, they switch ON for a shorter duration.

The combined effect of a large pool of EWH with random hot water use pattern gives the CLPU diversified load curve the shape of a large surge in diversified load (the restore load) immediately after the OFF-switching event, followed by a "decay" of the CLPU over the course of multiple hours. Illustration 8 shows the diversified demand of a pool of EWH during and after a DR event net of the diversified demand without DR.



(a) DR event: Off-switching **(b) DR event: Thermostat setback**

Illustration 8: Conceptual CLPU Curve After an OFF-Switching Event

As illustrated in Illustration 8(a), the restore load is the tip of the surge occurring immediately after the DR event. The effect of the CLPU then falls quickly (i.e. it decays) within the hour; next, some residual effect can be felt up to four hours after the surge; finally, the diversified load curve goes back to normal. This curve has been observed experimentally by Hastings (1980), Lee & Wilkins (1983), and Ton-That & Laperrière (1989) for example. Recent attempts to model diversified load through bottom-up

approaches, like that of Moreau (2011) and of Wong et al. (2013), succeeded in reproducing the same CLPU curve that prior authors had found experimentally.

Illustration 8(b) draws the profile of the CLPU for a thermostat setback DR command. At first, the DR event cause a sharp decrease in the diversified load close to that for a switching event, next the diversified load picks up again during the event, then the restore load is smaller than that for a switching event and its decay time is shorter. The shape of the CLPU curve for thermostat setback events as compared with that for switching events was studied by Saker et al. (2011) through computer-assisted modeling.

For any given pool of EWH, the height of the net restore load is a function of two main parameters: the duration of the event and the "natural" diversified load in absence of DR during the event. Duration and load, when combined together, can be expressed in the form of the amount of energy that would otherwise have been consumed by the pool of EWH in the absence of DR. Early work by Lee & Wilkins (1983), allowed for the development of equations to forecast the CLPU curve; these equations were expressed as a function of DR event duration, natural diversified load, and time after the event. Lee & Wilkins developed these equations based on least-squares curve fitting methods applied to data collected from load control experiments. Lee & Wilkins' equations are shown in Illustration 9, below.

Later, through a similar approach, two other researchers, Bischke & Sella (1985), established that the net restore load can reach twice the unconstrained diversified load or in other words, the *gross* restore load can reach three times the unconstrained diversified load as shown in Illustration 10. The gross restore load is the actual total diversified load immediately after the DR event; it does include the diversified load without DR (or "natural diversified load").

TIME ELAPSED AFTER RECONNECTION	UNCONTROLLED CLPU DECAY CURVE FOR ONE NORMALIZED HOT WATER	
	FOR E ≤ 3.164 kWh	FOR E ≥ 3.164 kWh
0:15	$-0.2173\ E^2 + 1.3750E + .2666$	2.442
0:30	Max (o, 0.6E - 0.1)	1.798
0:45	Max (o, 0.486E -0.243)	1:295
1:00	Max (o, 0.32E - 0.16)	0.852
1:15	Max (o, 0.2E - 0.1)	0.533
1:30	Max (o, 0.207E - 0.166)	0.489
1:45	Max (o, 0.16E - 0.16)	0.346
2:00	Max (o, 0.231E - 0.554)	0.177

Note: CLPU during the recovery period are shown to be a function of E, "Energy shed during disconnection". The notation max (0,...) means that for small values of E for which the second term becomes negative, the net restore demand is zero. Therefore, the length of the CLPU will be sort if the value of E is small.

Illustration 9: Equations Used to Forecast the CLPU Decay Curve
Source: adapted from Lee & Wilkins (1983)

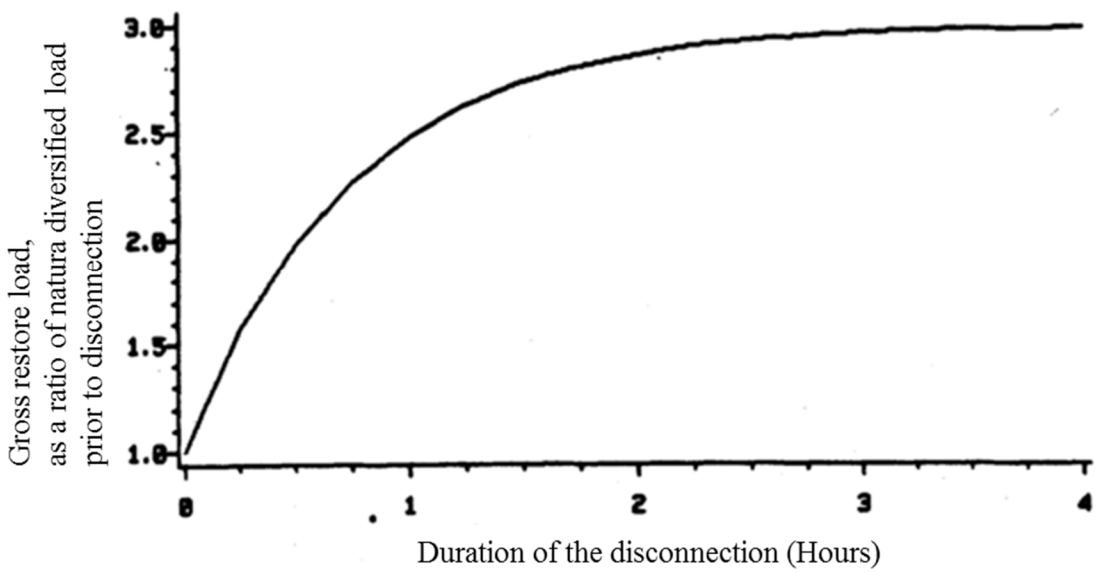


Illustration 10: Gross Restore Load versus Duration of the Switching Event
Source: adapted from Bischke & Sella (1985)

The graph in Illustration 10 shows that the gross restore load increases quickly for the first hour of disconnection reaching 2.5 times the diversified load without DR for a one-hour switching event, and then after two hours of disconnection it reaches a plateau at 3

times the natural diversified load. The gross restore load, as a ratio of natural diversified load, is physically bound to be the aggregated total power rating of the EWH divided by the natural diversified load.

Nowadays, the bottom-up EWH diversified load models used by researchers can forecast the shape of the CLPU curve for any event type and scheduling with ease because the models keep track of the temperature status for each elemental EWHs and determine if they would switch back ON upon the end of the event.

I did not use the bottom-up model, however, and used a top-down model, that of Lee & Wilkins (1983), for two reasons. Firstly, these models are owned by their developers. One cannot necessarily have access to them and use them. Secondly, these models require a high computing power. As will be explained in the next pages, developing cycling routine to control the CLPU requires lots of computing power on its own. Thereby, using a top-down approach to modeling the CLPU allows for a solution in an optimal cycling routine with the available computing hardware. The model developed by Lee & Wilkins (1983) was preferred due to its simplicity, availability, coherence with results by other authors, and the influence it had on future work on DLC.

Cycling

The maximum load shedding that can be obtained through DLC has to be equal or below the diversified load for the entire pool of EWH at any given time. Fortunately, the EWH diversified load in Quebec has a good correlation with the total of the power system, as shown in Illustration 11. The EWH diversified load peaks during winter mornings and afternoons coincide with that of the power system. Consequently, the maximum load curtailment can be achieved when it is most needed.

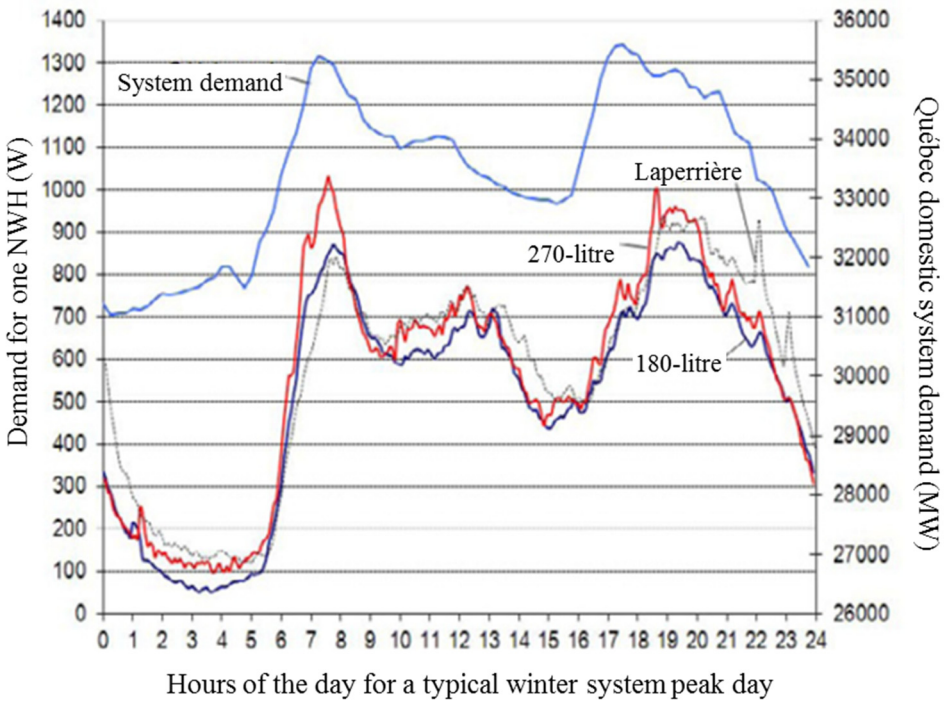


Illustration 11: Diversified Demand Profile of Domestic Water Heaters in Quebec

Source: adapted from Moreau (2011), fig. 4

If a system operator is to avoid the creation of a second peak due to CLPU, it may have to reduce the load curtailment it can expect from any given pool of EWH below the diversified load of that pool because the avoidance of CLPU is usually achieved through a grouping and staggering approach, also known as "cycling." Cycling entails the division of the pool of EWH into groups, each of which is attributed a sequence of ON- and OFF-switching commands, or "schedule." For example, a simple routine for a switching event could be: each time one normalized water heater (NWH) is switched back ON after a switching event, two NWH have to be switched OFF to avoid the CLPU and then one additional NWH would need to be switched OFF if the load curtailment is to be sustained. In this example, only a fourth of the total diversified load for any given pool of EWH can be shed while preventing the CLPU.

Utilities in the USA that were testing DLC with EWH in the 1970s developed early on cycling methods to mitigate the CLPU. Illustration 12 presents a cycling pattern that was used in Detroit, Michigan. The utility in Detroit had installed radio antennas across their service territory and each control switch installed on an EWH had a radio frequency receiver, which allowed it to receive control signals sent by the utility.

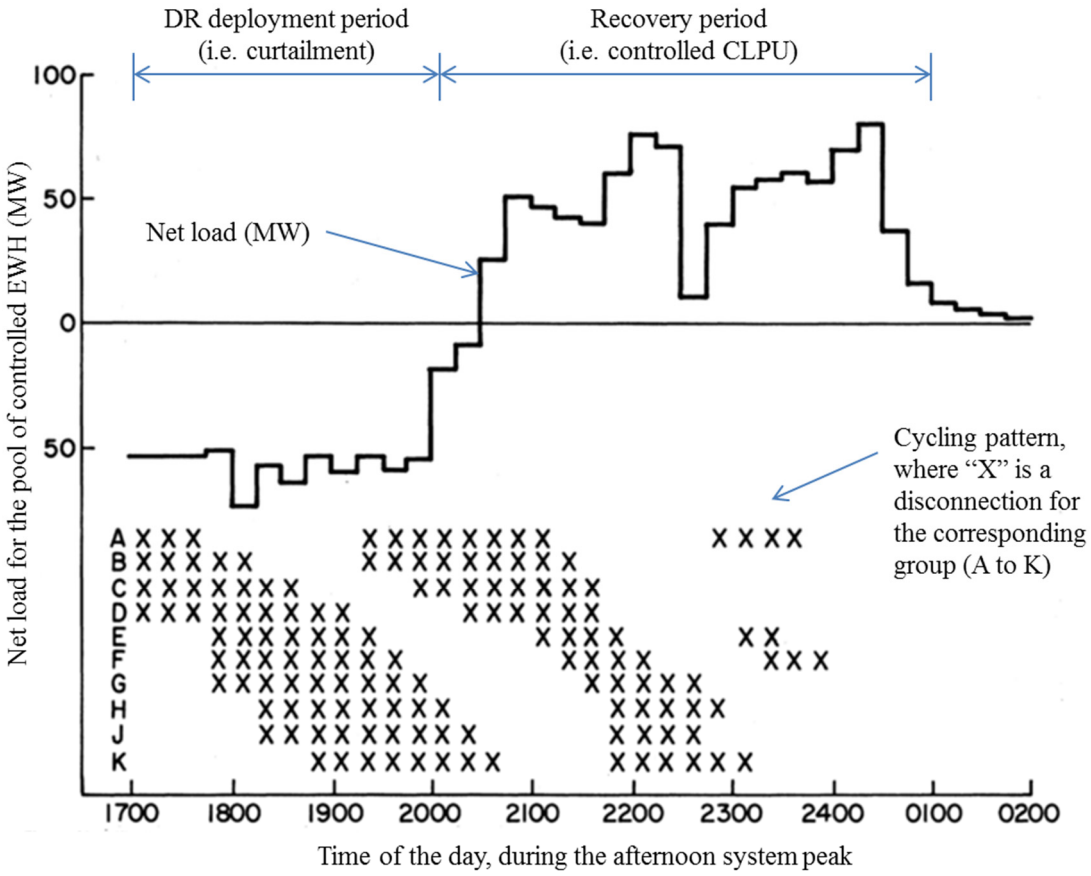


Illustration 12: Simplified Layout of Water Heater Load Reduction Program
Source: adapted from Hastings (1980), p. 1439

The utility in Detroit had divided the pool of 200,000 EWH that had enrolled in its DLC program into 10 groups (A to K) of equal sizes, as shown in Illustration 12. The "X" at the bottom of the graph show when the EWH in each one of the groups were remotely disconnected. The cycling pattern shown in Illustration 12 allowed the utility to shed

50 MW from 5 pm to 8 pm (3 hours), and then allowed the thermal storage of the EWH to be replenished in a controlled manner starting at 8 p.m. through 2 a.m. (6 hours).

Cycling Optimization

The cycling pattern used by the utility in Detroit had to be developed manually by its technicians. The utility DSM staff had created a few dozens DR patterns. The system operation team would select one pattern that best fit their need based on the next-day load forecast. The best pattern was the one that would match the duration of the peak, delay the thermal storage replenishment after the peak, and then pace the replenishment according to the ramp down of the system load.

In order to develop better cycling patterns quicker, later authors such as Lee & Wilkins (1983), in North Carolina, developed computer-assisted optimization algorithm that would create the best cycling pattern automatically for a given pool of EWH and for a given next-day system load forecast. The optimization problem is illustrated on the left hand side in Illustration 6. It shows that any given group of EWH has an associated diversified load and triggers CLPU when the natural diversified load is altered. The diversified load with or without DR (and associated CLPU) can be derived using the methods described in Section 1.5. Lee & Wilkins' method to forecast the diversified load and CLPU was a top-down experimental approach as described in page 31. Further to this, Lee & Wilkins solved the optimization problem through linear programming, which is an "educated" trial-and-error loop until the computer converges toward the optimal cycling pattern. Their optimization algorithm was allowed to vary both the number of groups, the size of each group, and the cycling schedule assigned to each group in order to achieve the maximum load shedding while avoiding a second system peak.

Bischke & Sella (1985) in Wisconsin, Cohen & Wang (1988) in California and Laurent et al. (1995) in Quebec proposed similar optimization approaches. The most recent work, that of Laurent et al., used a bottom-up computer-assisted modeling approach to forecast the CLPU rather than the top-down empirical approach used by the other aforementioned authors in the 1980s.

As DSM in general and DR in particular were scaled up across North-America, electrical component manufacturers and specialized vendors have developed a number of commercial solutions to operationalize DR. A list of commercially-available technological solutions is available in Appendix A. The telecommunication solutions as well as the list of control devices provided in Appendix A. The telecommunication solutions as well as the list of control devices provided in Appendix A prove that DLC for electric hot water is mature and viable. The extent of the list also point to the fact that a wide range of technological solutions exist to remotely control EWH.

The choice of the DR technological solutions depends on what the goals of DR are. DR performance thereby depends on what the system operator actually seeks to achieve. Chapter 3 explores the possible uses of DR in Quebec, which will point to how to best determine the performance of DR from a technical standpoint.

Chapter 3. Market Structure

Chapter 3, "Market Structure," provides a thorough substantiation of the approach to DR valuation through looking at the market structure of both Quebec and New York, one of the markets next to Quebec.

Chapter 3 starts with a high-level description of Quebec's electricity market in Section 3.1. This is followed by a description of the restructured export market of New York in Section 3.2. Then Section 3.3 exposes the variety of possible uses of DLC, many of which could be monetized for DR valuation purposes. Finally, Section 3.4 explains the implications of the market structure and operations on the valuation model. Chapter 3 will conclude by pointing to the two most relevant approaches to monetize the benefits of DR in Quebec: avoided cost of capacity and price arbitrage with New York, for example.

3.1 Domestic Electricity Market

Hydro-Quebec (HQ) is the main electric utility in Quebec. It is a state-owned company, a "Crown Corporation," and it has the monopoly[7] over generation, transmission and distribution in the province. HQ entails four main incorporated divisions, Hydro-Quebec Distribution, Hydro-Quebec Transénergie, Hydro-Quebec Production and Hydro-Quebec équipement et services partagés, to take on the market role of electricity distribution, transmission, power generation and construction projects respectively. Despite HQ's inherent primary mandate, which essentially is to supply electricity to Quebec's domestic market, HQ has been active in the export markets, in particular with the Northeast of the United States (Pineau, 2013, p. 370). The higher electricity prices in

[7] This is a simplification as there are a number of independent distributors and generators in Québec. These other market participants, however, all buy from or sell to Hydro-Québec (respectively), and their price is regulated in a similar manner to that of Hydro-Québec.

these markets lent themselves to attractive profits for HQ, especially given its low production cost facilities and water storage capacity, which allowed the company to deliver substantial dividends to its only shareholder, the Government of Quebec. The 2014 financial year was a record high for dividends with $2.5 billion (HQ, 2015b). This recent success was explained by a particularly cold winter season in North America's Northeast, which drove the electricity demand up and in turn increased the wholesale prices.

Table 2 presents a number of statistics providing context for both Quebec's and New York's systems as well as the current level of electricity trade. The New York system is the exterior market that I focus on for valuation purpose.

Table 2: Key statistics of Quebec's and New York's neighboring systems

	Quebec	New York
Domestic Consumption (2013)	173,300 GWh	147,899 GWh
Installed Capacity (2013)	Total firm capacity: **43,470 MW** Total w/ wind: 46,327 MW 36,643 MW owned by HQP +5,428 MW Churchill Falls (NL) +1,399 MW for other firm-power independent power producers (non-wind) +2,857 MW Wind	**39,039 MW**
Electricity Storage Capacity	176,000 GWh (northern hydro reservoirs)	0.290 GWh (one open-loop pump storage and 17 other smaller electro-chemical and thermal storage projects)
Demand Response	1,200 MW (all from industrial/large commercial interruptible rates, among which 300 MW is from Alouette aluminum smelter)	1,124 MW
Domestic Peak (Record high)	38,286 MW (Winter 2011)	33,956 MW (Summer 2013)
Fuel Mix (in %, 2013) *Note: In the NY column, parentheses indicate that imports were included in the breakdown.*	99% Hydro (Mostly large hydro) 1% Others: wind & biomass.	39.9% Natural Gas 32.9% Nuclear 18.3% Hydro 3.5% Coal 2.6% Wind -0.3% Pumped Hydro 0.7% Oil 2.2% Other renewables
Existing Interties	Total: **1,800 MW** (Direct), 2,925 MW (including ON) +1,800 MW Chateauguay-Massena Interties with ON, with possibility to redirect to NY: 1,125 MW	
Electricity Traded in 2013	QC to NY: 9,000 GWh (approx.) NY to QC: 530 GWh (approx.) Or: about 5.7% of total consumption	

Sources: EIA (2015b), FERC (2015), HQ (2011, 2014c), U.S. DOE (2016), NYISO (2015c), Whitmore & Pineau (2016)

Quebec's electricity retail prices are regulated based on cost recovery (plus a return on investment) and kept lower than market prices. The generation price (i.e. the commodity) is largely determined by a bill passed by the Government of Quebec in 2000. The transmission, distribution and customer service prices are all regulated. The price regulation is based on an average total cost approach also known as "cost of service" regulation, which is the conventional approach to electricity price regulation in North America.

The Government of Quebec took measures to control production price through the creation of the "Heritage Pool". The Heritage Pool is 165-TWh worth of electricity generation that HQ Production has to supply to HQ Distribution at a guaranteed flat price of 2.79¢ per kWh (pegged to inflation starting in 2014) for Quebec's domestic customers (HQ, 2014b). The same bill, which was an amendment of the Act regarding the Régie de l'énergie, also stipulated that all of the domestic consumption above the Heritage Pool, or "post-heritage electricity," would have to be supplied "by the market." The provision of post-heritage electricity then was tendered to local independent power producers by HQ Distribution, purchased from exterior markets or, in certain instances when ordered by governmental decrees, developed by HQ Production (Pineau, 2012, p. 47). It was the same bill that also obligated HQ Production to always supply the domestic market first. It is only the remainder of the production that is available for sale in exterior markets. Post-heritage electricity, however, only represents a small percentage of the overall domestic consumption (8.3 out of 173.3 TWh) and thereby wholesale price in Quebec is still heavily determined by Heritage-Pool price.

The Heritage-Pool price is particularly low for North America because of the historical context. Quebec was endowed the Heritage Pool, i.e. 165-TWh worth of cheap electricity, as a result of the large legacy hydro-power investments of the 20th century in Northern Quebec. The debt incurred from the investments has already been largely paid off and the cost of running the legacy hydro facilities and overhauling them when needed is relatively low on a per-kWh basis. The Heritage-Pool price may be lower on average than wholesale market prices in exterior markets, but it still is high enough for HQ Production to recover all of its cost and even make a profit.

HQ Transénergie and HQ Distribution must submit their electricity rates to oversight by the "Régie de l'énergie", the energy regulator. Transmission, distribution and customer service represent approximately 25%, 23% and 12%, respectively, of total residential retail rates (Pineau, 2012, p. 49). Production cost represents the remaining 40% of total average cost and flows through HQ Distribution to consumer as an operational expenditure.

Quebec residential electricity consumers do not pay the true market value of power. There are two reasons for this. Firstly, this is because of the Heritage-Pool price. Secondly, the regulator makes non-residential electricity end users pay higher rates so that residential rates can be lower by 20% than the actual cost of service. The final rate seen by residential customers on their electricity bill is approximately ¢7 per kWh (Pineau, 2012, fig. 49). As a result of this arrangement, Quebec's residential electricity consistently ranks among the least expensive in North America (HQ, 2014a).

Furthermore, Quebec residential electricity consumers pay an almost flat retail price that does not represent the real-time marginal production cost. HQ's uses an increasing-block structure for its residential tariff. The first 30 kWh being used every day are tariffed

at ¢5.68 per kWh, and the remainder is tariffed at ¢8.60 per kWh[8] (excluding all sales taxes). It is a common structure for electricity tariff, globally, but it is not a time-sensitive price structure such a time-of-use tariff or a critical peak pricing tariff, which are increasingly common in North America.

HQ Production is not regulated, unlike HQ Distribution and HQ TransÉnergie, and thereby is not subjected to the same degree of regulatory oversight by the Régie de l'énergie. It is within TransÉnergie that resides the system operator, System Control Centre, which mirrors some of the functions that are generally under the responsibility of system operators found in most neighboring power markets. HQ Distribution has a team of power brokers, residing in the Energy Supply Department[9], who buy any energy or capacity required to meet the domestic demand from neighboring markets when it cannot be met through the Heritage Pool. HQ Production has also a team of brokers nested within, "Le Parquet", that schedule electricity transactions on exterior wholesale markets, using energy and capacity left after its Heritage Pool obligations were met. Le Parquet seeks to make the most with HQ Production's large Northern hydro reservoirs to maximize revenues in all exterior markets. Le Parquet run the generation units and use the transmission lines at maximum capacity during peak times when the exterior wholesale market prices are high and they import when the prices are low.

The Heritage Pool price is not time-sensitive; i.e. it stays the same from one hour to the next. Furthermore, HQ Production, because it is a non-regulated entity operating in many competitive wholesale markets (i.e. that of Ontario, New York and New England),

[8] Tariff structure as per December 15, 2015, as seen on my own Hydro-Québec electricity bill in Montréal, QC. The tariff structure also includes a fixed price of ₵40.64 per day.
[9] In French: "Direction Approvisionnement en énergie"

does not disclose any information about its production cost to prevent its competitors from anticipating its bidding strategy, which would give them an advantage in the markets. Using hourly marginal production costs, as it was once done in other regulated markets in North America, is thereby not an option for valuating DR from an outsider's perspective; hence the decision to look at exterior-market wholesale prices rather than hourly marginal production costs to value DR in Quebec.

In conclusion, the market structure described above has the following implications on DR valuation in Quebec:

- Low retail prices explain the high penetration of domestic hot water heating.
- Since retail prices are not time-sensitive, there is no *natural* market incentive for household to adopt technologies that shift the peak demand of their EWH outside of the system peak demand. All decentralized DR strategies that rely on a time-sensitive price signal, like those using on-board learning optimization algorithms as described in Table 1 on page 26, are irrelevant to the Quebec market in the short term.
- The priority that HQ Production has to give to domestic demand over exterior markets coupled with the low retail prices in the domestic market due to governmental interventions and regulation cause domestic demand to be higher than market equilibrium if such constraint did not exist, thus limiting HQ Production's ability to export and maximize revenues and profit.
- Since HQ's real-time marginal production cost are not disclosed, then wholesale price in exterior markets become the only source of information available to convert curtailments into value streams.

3.2 Export Markets

There are five markets surrounding Quebec: Ontario, Labrador (soon to be connected with the Newfoundland Island), New Brunswick, New York and New England. I will focus on the New York market. There are two reasons for this. To start with, New York, along with New England, is a traditional market for Quebec's electricity. New York and New England have been purchasing more of Quebec's electricity than all of the other aforementioned markets (for instance, see the data discussed in Amor, Pineau, Gaudreault & al. (2011)). Furthermore, when comparing New England and New York, New York is the market where it is easiest to obtain detailed historical price data; hence, the preference for New York's prices for valuation purposes. New England's wholesale prices are typically higher than that of New York, and thereby the results of the valuation is likely to be more conservative if using New York prices than if using the highest prices of both markets. Sales of electricity to New York is poised to increase in the medium term because a 1,000-MW new transmission line project linking Montréal to the New York City metro area is in the advanced stages of planning (Champlain Hudson Power Express, 2015).

New York State restructured its power market in the 1990s. Not only did New York break down its integrated monopoly utilities into distribution, transmission and production companies, but it also created a competitive wholesale market and introduced competition in electricity retail (while *ownership* of distribution assets remains regulated). A competitive wholesale market allows generators located inside (or outside) the jurisdiction to compete against each other on price (Kopsakangas-Savolainen & Svento, 2012, p. 6). The New York market is coordinated by the New York Independent System Operator (NYISO), which was created in 1999 from what was then the New York Power Pool

(NYISO, 2015b). Under NYISO, the New York power market went from being essentially made of eight vertically-integrated monopoly utilities to becoming a competitive wholesale market with more than 400 participants (NYISO, 2015a).

Characteristics of the NYISO Wholesale Market

New York's wholesale market was designed as a generators' pool[10]. In generator-pool wholesale markets, all generators submit a bid to one central buyer, i.e. the pool (2006, p. 5.4). This means that decisions determining which electricity resource to use are driven by the variable production cost. All generators bid a price that, in theory, should match their variable cost. All generators whose bid was lower than the clearing price will run their facility and receive the clearing price. All generators whose bid was higher than the clearing price will refrain from producing. Generators with a low variable cost are thus dispatched first.

New York's wholesale market is a "two-settlement" system, which means that NYISO runs a day-ahead market (DAM) and a real-time market (RTM). Under the DAM, producers and buyers plan sales/purchases before the actual time of production/consumption. The purpose of the RTM is to fill the gap between *forecasted* and *actual* production/consumption (Craan, 2009). Under the DAM, production/consumption is scheduled one day prior to the dispatch day. A daily dispatch schedule uses one-hour increments; i.e. the first dispatch window starts at midnight and ends at 1 am, the second time window starts at 1 a.m. and ends at 2 a.m., and so on until the last time window from

[10] NYISO's rules also allow bi-lateral contracts, which – despite being important to the Québec-New York electricity trade discussion – are not relevant to this Thesis. In a bi-lateral contract, one generator and one buyer reach a price agreement, then they enter into an over-the-counter contract over a pre-determined production level and schedule, and finally they give an advance notice to the system operator for the related production/consumption to be netted from the pool.

11 p.m. to 0:00 a.m.). The day-ahead bidding closes at 5 a.m. prior to the dispatch day, then NYISO publishes its own load forecast for the dispatch day at 8 a.m., and finally the day-ahead schedule and price is posted at 11 a.m. The dispatch day therefore starts 13 hours after. New York's RTM is a hour-ahead bidding scheme in which the bidding closes 75 minutes before the dispatch hour. Next, the production/consumption commitment schedule is posted 45 minutes before the dispatch hour, and then the commitments are confirmed every 15 minutes. The generators are actually dispatched every 5 minutes, and finally the clearing price is known at the very end of the dispatch hour (NYISO, 2013, pp. 2–4). NYISO always has reserve capacity on standby, ready to be dispatched under a 15- or 5-minute notice if the demand spikes up or if generation unit(s) fails unexpectedly. NYISO purchases regulation services to do the fine-trim adjustments between production and demand at a 6-second interval. Reserve and regulation will be further defined in Section 3.3.

A key assumption of my thesis is that if HQ Production's traders were to dispatch residential DLC to achieve incremental economic gains when bidding on the New York's wholesale market, they would have to schedule the DR events based on a price forecast one day before the forecast. The main reason for this is as follows, in order to achieve a positive revenue increment from DLC, the traders will have to meet the two following conditions: first the deployment period must be scheduled when the prices are as high as possible and then the recovery period must occur when the prices are as low as possible. In order to find the DLC dispatch schedule that will yield the highest increment with a degree of certainty, I postulate that HQ Distribution's traders would schedule the DR events based on the DAM prices that are posted on the day before the dispatch day. DAM

prices are hourly prices, which explains why net load calculations that are presented in Section 4.1 were fitted into an hourly schedule even though they were calculated using a 15-minute increment.

NYISO has a day-ahead DR program (DADRP). The DADRP allows curtailment service providers, or third-party aggregators, to bid in DR resource into the DAM as if they were a generator (NYISO, 2003). As such, DR scheduling in Quebec will be similar to DADRP, only that the load curtailment would actually happen in Quebec, not in New York, and HQ Production would be able to bid the capacity that was "freed up" in Quebec into New York's regular DAM. DADRP is mainly mentioned in support of a key assumption of my thesis – i.e. which is to use DAM prices and DAM time increment in the DR valuation method.

DAM and RTM prices have to be adjusted for basic transmission losses (typically fairly small) as well as for bottlenecks in the transmission network, which lead to congestion and thus even more losses (which may be substantial). Location of the demand is one determinant of congestion and transmission losses, and thus the operator sets Location-Based Marginal Prices (LBMP) for different areas of the independent system as well as the specific interties between independent systems. Each LBMP is the sum of the commodity price, the marginal price of congestion, and a correction for the marginal price of transmission losses (Villeneuve, 2011, p. 30). As such, due to its position at the Northern tip of New York power transmission system, the intertie between HQ TransÉnergie and NYISO's transmission systems has its own LBMP, the "HQ Zone" LBMP.

NYISO's Growing Need for Flexibility

Adoption of distributed energy resources (DER) is strong and growing in New York. Photovoltaic solar (PV) is the one resource with the largest adoption, about 80 to 90% of DER. New York ranks as the fifth state for cumulative installed capacity of DER under two megawatts with 216 MW installed (DNV GL Energy, 2014, p. 2). The growth of PV, which is a variable renewable energy resource, is continuously pushing NYISO's grid to its limits and increases the need for flexible resources.

The need for additional flexibility is a growing issue worldwide for system operators. Illustration 13 below, shows the need for flexibility on the left hand side, and technological solutions to tackle the increased need for flexibility on the right-hand side. DR is one of them, under the "Demand-side management *and response*" category. Interconnection with adjacent markets, such as that of Quebec, is another. Quebec has the potential to offer additional flexibility to NYISO through its existing interties and the new intertie that is currently under development.

In Illustration 13, net load is defined as the natural load (i.e. the demand) minus the output of all variable renewables energy resources. The demand is variable and uncertain by nature and thus flexibility has always been required by system operator to address the natural variability of the demand. So far, flexibility has been delivered through wholesale market design (e.g. DAM, and RTM), and through a number of technological services. The increasing need for flexibility in NYISO also means an increased demand for these services.

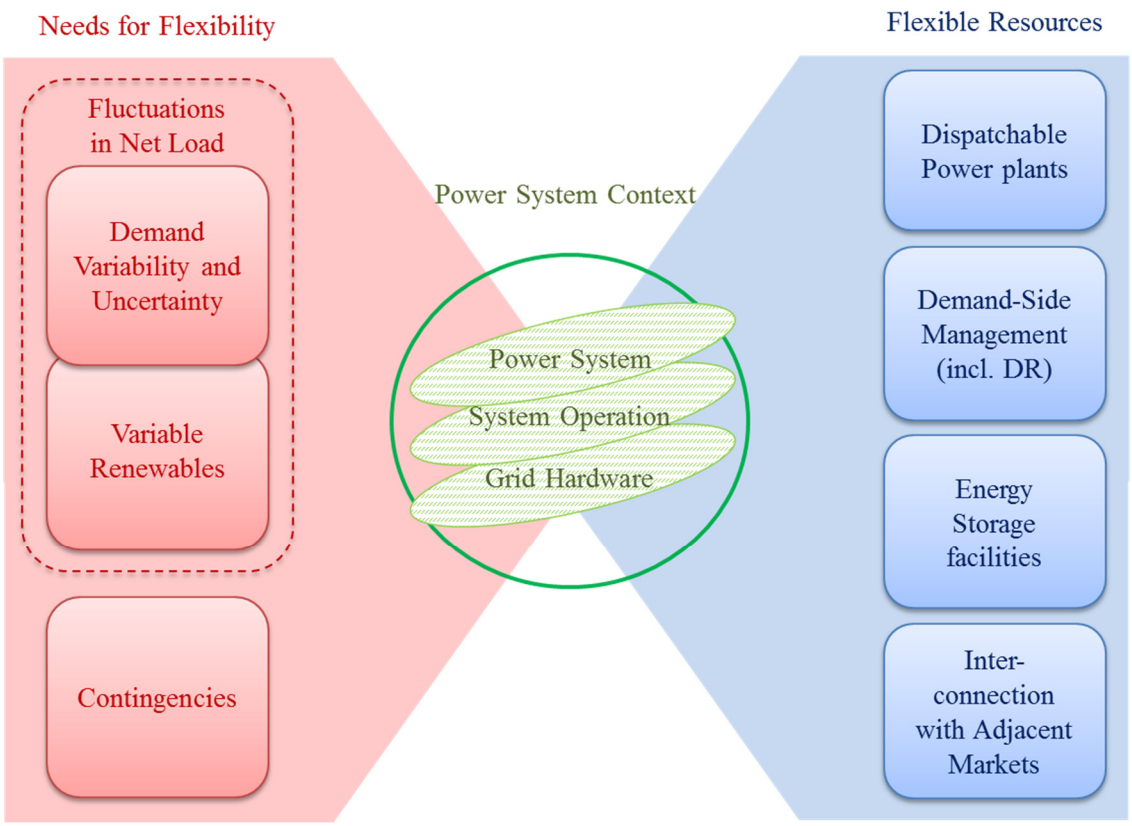


Illustration 13: Need for Flexibility against the Main Types of Flexible Resources
Source: adapted from IEA (2011), page 36

3.3 Potential Market Role of DR

Before the rise of the variable new renewables, flexibility needs were met through a number of technological solutions grouped together under broad categories that are referred to as "services." Increasingly in competitive markets such as that of NYISO, services are left to market participants to provide through auctioning. The tendering processes should, in theory, not take into consideration the technology being offered as long as the services are being delivered in a manner that suits the system operator requirements. Increased needs for flexibility calls for an increased need for services, and DR is known to be a technical solution capable to deliver many of these services.

Market Services

The paragraphs below will provide a comprehensive list of the market services. Section 3.4 will present which were selected services for DR valuation purposes and substantiate the choice. In North America, the terminology used to describe services was defined by the North American Electric Reliability Corporation (NERC). The following list of services was developed by comparing research work by HQ (2008, p. 16) and by the Freeman-Sullivan Group (2014, p. 25) (now Nexant):

- **Production capacity modulation:** solutions that allow the scheduling and dispatch of generation facilities for each "dispatch hour". In NYISO, this service is provided through the DAM and the RTM described in Section 3.2 under the purview of an independent system operator. In Quebec, the system operator sits within HQ Production and scheduling decisions are made through the use of a proprietary optimization model, as described in Section 3.1.
- ***Intra-hour* operating services**: services that are continuously solicited as part of grid operation
    - **Frequency regulation:** technological solutions that are continuously synchronized that can be dispatched instantaneously, are continuously solicited and make up for the small gaps between production and demand due to short-term demand forecasting errors. These technical solutions need to be responsive to a real-time control signal or in other words the area control error signal or ACE.

    - **Load-following reserve:** solutions that make up for unpredicted up- or down-ramps occurring after the start of the dispatch hour. These are called with a 10-, 20- or 30-minute periodicity.

- ***Intra-hour* contingency services**: services needed to address any form of unexpected power system outage.
    - **Spinning reserve**: technological solutions that are continuously synchronized with the grid and can be dispatched 0 to 10 minutes after being notified.
    - **Non-spinning reserve** (10- or 30-minute reserve): solutions that require advanced notice before being dispatched.
- **Operating reserve margin:** standby solution needed to make up for a gap between production and demand due to forecasting errors or unexpected outage for a time horizon of 1 to 48 hours.
- **Production capacity adequacy:** standby solution to ensure that the power system can sustain the highest net load peak for a time horizon of multiple years (e.g. 5 years). Capacity adequacy is a basic requirement for the long-term reliability of the system.

DR as a Market Service(s)

The DR solution that studied EWH direct load control could potentially supply one or many of the aforementioned services, as shown in Illustration 14 below.

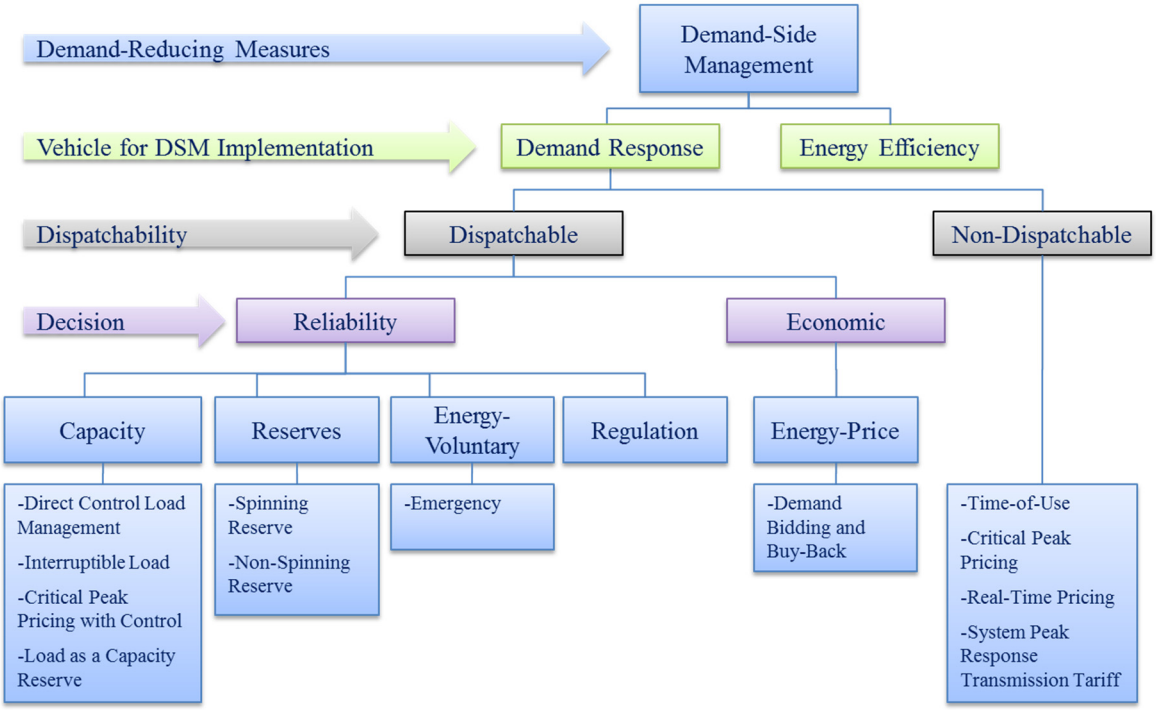


Illustration 14: Demand Side Management Product Categories
Source: adapted from NERC (2011), page 9

The five levels of the pyramid structure shown in Illustration 14 are (from top to bottom):

- **Demand-Reducing Measures:** DR pertains to the broad category of demand-side management (DSM) programs or policies.
- **Vehicle for DSM Implementation:** DR and energy efficiency are two different vehicles that fall under the DSM umbrella. The latter aims at reducing overall energy consumption, usually with little concern over the timing of the load curtailment and the former focuses essentially on the timing of the load curtailment and usually results in little to no reduction in overall energy consumption.

- **Dispatchability:** Dispatchability was discussed in Section 1.3. It was described as active DR (i.e. dispatchable) and passive DR (i.e. non-dispatchable). The former relies on the system operator triggering curtailment from a central location through communication and information technologies and the latter is decentralized and relies on an aggregate of energy users reacting to time-sensitive price signals such as a TOU, CPP, or RTP.
- **Decision:** Centrally-dispatched DR can be triggered for reliability reasons or for economic reason. Either way, DR will have a monetary value. If triggered for economic reasons (economic dispatch), DR will be valued through wholesale prices – i.e. deploying DR when prices are high and allowing recovery when prices are low. Economic dispatch of DR offers a production capacity modulation service. If triggered for reliability reasons, then the monetary value of DR will either be the market price of the corresponding service in a competitive market or the long-term marginal cost of the corresponding service in a regulated market.
- **Services:** The bottom layer in Illustration 14 lists the services that can be offered through DR: capacity adequacy, reserves (load-following reserve, spinning reserve, non-spinning reserve), operating reserve margin (for use in emergency circumstances), and production capacity modulation (through demand bidding and buy back).

A time-sensitive pricing approach, showed on the fourth and fifth layer at the right-hand side of Illustration 14, is not meant to supply any specific services to the market. Instead, it will reduce the need for these services, thereby using price elasticity to counterbalance the effect of an increase in penetration of variable renewable energy resources.

All of the services listed above can be attributed a monetary value; either through market pricing or through establishing its long-term marginal cost. A key step before developing an approach to the valuation of DR in Quebec was selecting which services can be provided by EWH direct load control.

3.4 Services Applicable to Water Heater DLC

An elimination process was used to select which services are applicable in Quebec . The applicability of each service and of each approach was determined through looking at technological, local marketability considerations, and finally inter-market trade considerations.

Technological Considerations

Direct load control of water heating has a wide array of possibilities in terms of market services depending on the extent to which the baseline EWH tank and plumbing is modified.

As discussed in Section 2.2, with a rather simple modification to the system, i.e. the addition of a simple remotely-controlled load switch, water heating DLC can offer capacity-adequacy services, many reserve services (anything that does not require down-ramping), and can even be used for economic-dispatch purposes. The one limitation is the legitimate concern of most households over the possibility of lacking hot water. There is a number of technological and program-design solutions to this one particular concern; one of them being to add a temperature sensor on the tank to prioritize the re-connection of the tanks whose thermal energy storage will be most depleted.

If the utility were ready to replace the tanks and modify the plumbing, then water heater DLC could potentially also offer regulation services and down-ramping (i.e.

dumping load). Regulation services require multiple temperature measurements inside the tank to monitor stratification and thus require substituting the tank with a new one that is equipped with the sensors. Acquiring the down-ramping capability requires gaining the ability to overheat the water, and thus a thermostatic mixing valve would be needed at the outlet of the tank to mitigate safety concerns. Whether that is the preferred approach depends on the value attributed to regulation and down-ramping. Otherwise, if the utility or system operator was to prefer a decentralized, passive-DR approach rather than something more direct, then the tank would need to be replaced because the tank control system would require an artificial intelligence on-board that would be able to balance out multiple criteria such as occupant comfort, time-sensitive tariff, and typical hot water usage in each household. I postulate that a full tank replacement would be either too capital-intensive (thus *not* cost-effective) if done through a direct-install approach or too slow to take place if done using rebates or mandatory standards for instance. Frequency regulation as well as any form of down-ramping load following should thereby be excluded from the valuation.

Local Marketability Considerations

There are three power services in Quebec that are established through a competitive-market approach following the 2000 amendment to the Act regarding the Régie de l'énergie. Quebec's version of a competitive-market approach is different than that of NYISO. Competition in Quebec relies on HQ Distribution sporadically launching competitive tendering processes for specific services on an as-needed basis.

- **Renewable energy**: A number of times in the past, HQ Distribution led competitive tendering processes of blocks of renewable energy supply, such as wind, small hydro

or biomass, to top off its domestic demand above the Heritage Block. Each tender aimed at one specific renewable energy resource. Typically, independent producers were asked to bid in a flat price, which, if accepted, gets locked in for a pre-determined duration. Despite being on the public record, these prices are not time-sensitive, and thereby could not be used for valuation purposes of a technological solution, such as DLC, in which the timing of the curtailment is all that matters.

- **Production capacity adequacy**: For the first time in March 2015, HQ Distribution launched a competitive tendering process for 500-MW worth of standby capacity during its domestic system peak periods (HQD, 2015b). The winner of the 500-MW block resulted in being HQ Production, and they locked in a price of $106.00 per kW per year (HQ, 2015a). DR could be used to provide capacity adequacy in replacement of this standby capacity. This number, $106.00/kW-year, can thereby be used for valuation purpose. In fact, this is the value that was used by HQ Distribution to assess the cost-effectiveness of the program-wide residential DR program that it intends to launch in the next months (HQD, 2015e, p. 24). As a point of comparison, in the neighboring province, Ontario, the Independent Electricity System Operator's (IESO) Demand Response Auction for which the results were released on December 10, 2015, resulted in a market price of $378.21/MW-day (during the summer or 183 days) and a market price of $359.87/MW-day (during the winter or 180 days) (IESO, 2015) or respectively $69.21/kW-summer and $64.78/kW-winter (or $134/kW-year).
- **Wind energy balancing services**: HQ Distribution tendered the procurement of wind energy balancing services in July 2015 (HQD, 2015d). The contract was awarded to the only bidder, HQ Production. HQ Production actually committed to delivering a

package of services, which essentially will turn wind power, a variable resource, into a firm resource from the perspective of HQ Distribution. Under the term of the request for proposal, the successful bidder was to absorb the electricity generated by all wind turbines in real time, and deliver to HQ Distribution, on demand, a capacity equivalent to 40% of the nameplate capacity of the wind turbines during the winter and 30% during the remainder of the year. To achieve this, the successful bidder has to provide operating reserve margin, upward and downward load-following reserve as well as frequency regulation in sufficient amount to cope with the added variability caused by wind power. HQ Production offered balancing services enough to cope with the variability introduced by 3,727-MW worth of wind turbines (HQD, 2015a) –2,857 MW that were already installed and plus a new incoming tranche of 870 MW. The price agreed between HQ Distribution and HQ Production was not disclosed.

Unlike in the NYISO, all of the services listed in Section 3.3 except for capacity adequacy, such as regulation, reserve and capacity modulation, are not procured through an open auction in Quebec for which the clearing price is on public record and can be used for monetizing. In addition, HQ does not publish marginal cost numbers for the services that could be used in a cost-benefit analysis. It is thereby challenging in Quebec to actually value most of market services through the use of domestic marginal cost numbers.

That being said, if the marginal cost of regulation, load-following reserve and operating reserve margin services (or any of the other services) were on the public record, it is reasonable to assume that these marginal cost would be relatively low compared to market prices in other jurisdictions. The reason for this is that Quebec has a large supply of dispatchable power plants in the form of its legacy reservoir hydropower. By the account

of Harris (2006) and the International Energy Agency (2011), reservoir hydropower can provide production ramping capability in a reliable manner on virtually any timescale (e.g. 6-second, 5-minute, 30-minute, etc.). HQ Production's hydropower facilities allows Quebec's grid to cope with an increased need for flexibility better than most other jurisdictions. This explains why procuring additional flexible resources are low on HQ's priority list. In 2008, HQ conducted an extensive jurisdictional scan on flexibility needs as a result of an increased penetration of wind energy, and concluded that the flexibility needs could be met at a low cost on its system (HQD, 2008). In 2012, Accenture, a large consultancy, pointed to the availability of dispatchable power plants as a justification for the low level of interest of HQ Distribution in taking advantage of the new advanced metering infrastructure being deployed to acquire additional flexibility services (Accenture, 2012).

The evidence points toward NYISO being in need of flexibility more than Quebec. The valuation approach thereby focuses on the possibility to *export* the extra flexibility provided by DLC in Quebec.

Inter-Market Trade Considerations

The next paragraphs will look at how HQ Production could sell the extra flexibility from DR to NYISO. In theory, HQ Production could potentially use DR to offer operating reserve margin or even intra-hour contingency reserve (spinning or non-spinning) to New York as a starting point. This, however, would require complex inter-market arrangements. Such arrangements are a possibility; and, in fact, they are being worked on at the moment (Hydro-Quebec Energy Marketing, 2014, p. 3; IESO, 2014, p. 14) but they are not fully settled yet. Moreover, it is not yet confirmed whether HQ Production would rely on DR to

provide the services, or use its own existing resources, which are in sufficient supply during most of the year. This option was thereby excluded from valuation.

Finally, DR could be dispatched to bid on the demand when the prices on the New York wholesale market are high, and then use lower market prices after the deployment period to buy back the energy and allow recovery. This is an option that was retained for valuation purpose.

Economic dispatch, such as the approach suggested in the paragraph above, is a relatively new application for DR and faces a number of marketability challenges in North America. These challenges entail market rules and requirements imposed on generators and service that are incompatible with DR and thus have hindered the ability of "curtailment providers" from bidding in the service markets (Cappers, MacDonald, Goldman, & Ma, 2013). None of these complications, however, are applicable to the proposed configuration, essentially because what happens beyond the intertie with Quebec will be invisible to the NYISO and its rules. The only change that NYISO will see is HQ Production offering more electricity to the New York wholesale market as a result of DR, and HQ Distribution demanding less electricity from its wholesale market also as a result of DR.

I made the key assumption that no transmission capacity constraint exist between Quebec and the NYISO. At the moment, this is a strong assumption because the transmission lines are congested during peak time in the winter. However, transmission is poised to become less of an issue due to the incoming 1,000-MW Champlain Hudson Express transmission project, as well as all of the other projects that are under study to connect with New England, such as the Northern Pass, the Green Line (HQ, 2016) as well

as the Clean Energy Link (Chesto, 2016). The connections to New England will create arbitrage opportunities with NYISO.

In conclusion, utilising the New York wholesale prices for DR valuation is equivalent to HQ Production selling capacity modulation achieved through DR in the domestic market to New York. Operating an competitive wholesale power market is the primary mechanism to cope with the increase in flexibility needs, according to the International Energy Agency (2011). The additional needs for flexibility due to an increasing uptake of variable renewables in New York will be reflected in the wholesale markets by increasing the prices when production up-ramping is needed above what is currently available. This is an opportunity that HQ should be pursuing because it will both increase its revenues and help New York integrating new renewables into its power grid.

Valuation of DR in Quebec therefore entails the two following cash flows: avoided cost of capacity (for adequacy) and price *arbitrage* between Quebec and NYISO, i.e. incremental revenues accrued on the NYISO market through economic dispatch of DR.

Chapter 4. Valuation

The valuation of DR in Quebec consist of estimating the incremental cash flows (benefits) that would be generated through a residential direct load control in Quebec targeted at electric water heaters. The result should take the form of an annual benefit, in real dollars, for one NWH, which can be scaled up based on the number of participants that will enroll.

DLC performance should be measured in term of the magnitude of the load curtailment that is possible and the duration of the load curtailment period (i.e. the *deployment* period). As thoroughly discussed in Section 2.2, DLC performance has two critical constraints: the cold load pick-up (CLPU) which needs to be carefully paced in order to avoid creating a second peak, and a lack of hot water. The latter needs to be minimized in order to avoid dissatisfaction among DR program participants, which might ultimately lead to attrition.

DLC performance should be determined according to its intended purpose(s). In the previous chapter, it was determined that DLC's usages will entail two components. Firstly, it will include "load curtailment" for system capacity adequacy purpose, i.e. the ability of HQ to sustain the worst peak demand in an emergency situation. The valuation approach applied to emergency load curtailment will be described in Section 4.1. Secondly, DLC's benefits will include additional revenues accrued through price arbitrage between Quebec and New York, or "economic dispatch" of DR. The valuation approach applied to economic dispatch will be described in Section 4.2.

4.1 Emergency Load Curtailment

Capacity adequacy is typically planned to sustain the worst peak for every given number of years. DR is a product that can help with adequacy by offsetting the peak, rather than adding to the supply. The minimal capacity that a certain jurisdiction disposes of to

sustain its peak demand must meet with the minimum capacity threshold established by the loss of load probability (LOLP) method. In that, HQ Distribution complies with the requirement of the Northeast Power Coordinating Council, Inc. (NPCC), which is not to surpass a LOLP of 0.1 day per year (HQD, 2013, p. 34; NPCC, 2015). In practice, this means that the likeliness of DR to be triggered for any given year to avoid loss of load is relatively low. DR used for adequacy purpose would thereby only be triggered in rare emergency situation (if at all); i.e. once every few years.

HQ Distribution plans on needing additional capacity to ensure system reliability starting in the winter of 2018 and by then wishes to have acquired the ability to shed 150-MW worth of its domestic load for adequacy purpose by that time. HQ Distribution also indicated its intention to acquire a total of 300 MW of DR capability by the winter of 2021 (HQD, 2013, p. 28).

Since emergency load curtailment situation would be rare events, it seems reasonable for the utility to trigger events that would disconnect all of the controlled EWH in households that would have enrolled in the DR program for an undetermined duration, thereby disregarding the temporary discomfort (i.e. lack of hot water) that this might cause to the participants. The EWH could then be slowly reconnected thorough the night to avoid a second peak because of the CLPU. I assume this minor inconvenience for the participants would be acceptable because it would only occur rarely.

Performance Evaluation

When CLPU and lack of hot water are not a consideration, as it is the case for rare emergency situations, then determining the performance of DR can be straightforward. The performance achieved by DLC for one normalized water heater (NWH) simply amounts to

the diversified load for that NWH at any point in time. The winter diversified load curve for one NWH in Quebec was determined with a fair degree of accuracy by Laperrière (2008) and Moreau (2011). Illustration 11 shows the diversified load curves by Moreau and Laperrière superimposed with the system load curve for a typical critical-peak day in Quebec, in which the peaks occur at around 5 p.m. in the afternoon. Reading from Illustration 11, the maximum load shedding possible coinciding with the 5 p.m. system peak is about 700 W per NWH. The deployment period would need to last for three hours at a minimum to shift the energy past the winter peak. This number, 700 W, is also the curtailment level that was used by HQ Distribution as an assumption for the valuation of its own residential DLC program (HQD, 2015e, p. 37).

Valuation

The monetary value stream obtained from load curtailment for adequacy purpose is known as "avoided cost of capacity." Avoided cost of capacity usually gets quantified as a marginal cost per kW, which then gets turned into an annuity. HQ Distribution publishes an official "avoided cost of generation capacity" on a yearly basis. The latest illustration posted by HQ Distribution is $106.00 per kW per year and is pegged to inflation (HQD, 2015c, p. 5). This rate is commensurate with the clearing price of the latest tender for standby generation capacity. The tender was won by HQ Production. They proposed the generation capacity of its new production facilities, the La Romaine hydropower complex. The La Romaine facilities are located in the Lower North Shore, around 1,371 km from Montréal and 1,114 km from Quebec City. There was no clear indication in the official request for proposals (HQD, 2015b) that bidders had to account for transmission losses from the point of production to the main load centres such as Montréal or Quebec City in

the proposed price[11]. Consequently, it is a fair assumption that the clearing price, $106.00/kW-yr did not include transmission losses. The avoided cost of capacity must also account for both transmission and distribution (T&D) losses.

The best practice in estimating avoided generation capacity for DR stipulate that the avoided cost must also include the planning reserve margin (Liu et al., 2015, p. 66; Woolf, Malone, Schwartz, & Shenot, 2013, p. 41). The planning reserve margin (PRM) is the capacity required in addition to the capacity needed to supply highest net peak demand of the system. The PRM may be needed to make up for a gap between production and demand due to unexpected outage that may coincide with peak time.

Both the T&D losses and the PRM ought to be combined as per the following equation:

Avoided capacity cost = Generation avoided capacity cost * (1 + PRM) / (1 – T&D losses)

Where:

- HQ Distribution uses a PRM of 11.1%[12].
- HQ Distribution uses an average 2.2% of distribution losses and 5.6% of transmission losses for a combined effect of 7.9% of T&D losses in its 2014-2023 supply plan (HQD, 2013).

[11] A number of references were made in the call for proposal to the effect that network losses were going to be estimated as part of the tendering process, but the document did not contain any clear statement that prices submitted by all bidders had to be adjusted to reflect network loss between the point of generation and a large load centre. On the first hand, it is standard practice to account for transmission losses to the point of delivery in wholesale prices. On the second hand, bidders in a competitive tendering process will be reluctant to account for network losses if not provided with the certainty that all other bidders will do the same because they would put themselves at a disadvantage. This is particularly true for HQ Production (the successful bidder) due to the remote location of the La Romaine hydropower plant. In the end, I decided to assume that it was not included in the prices proposed.

[12] Ratio between the reserve margin and anticipated system peak from 2020 to 2023 (HQD, 2013, p. 28).

The avoided capacity cost including both PRM and the T&D losses thereby is $127.87 per kW per year. At $127.87 per kW per year, the 0.7-kW curtailment (700 W) per NWH is thus worth a value stream of $89.51 per year per NHW.

4.2 Economic Dispatch

The second use of DR, economic dispatch, is also the one use that requires the most complex approach to optimize performance and value. The value streams sought for through economic dispatch of DR in Quebec comes from intermarket price arbitrage with New York; i.e. being able to offset domestic consumption during forecasted wholesale price spikes in New York and then recover the level of thermal storage in EWH after the price spike by buying back cheaper electricity in the late evening and in the night.

Using DR for economic reasons entails a frequent triggering of DR events, which means that the utility must have a good control over the CLPU in order to avoid a steep restore load and pace the thermal energy recovery over a long duration. It also means that the utility must ensure that none (or at least *few* of the water heaters) remain disconnected for a long duration. This can be achieved through using a cycling strategy as laid out in Section 2.2.

Approach to Performance Evaluation

In order to solve the valuation problem of economic dispatch, my work must thereby answer the two following questions.

- **What is the *Best DR routine possible*?** In other words, what is the best curtailment that can be achieved during the deployment period while pacing the recovery (or CLPU), and then what would the recovery load profile be?

- **What is the *Best dispatch timing and deployment length?*** In other words, when must a DR event be triggered to obtain the highest revenues from price arbitrage, how long must the deployment duration be and how long must the recovery period be?

The answers are divided in two parts; one section for each question. The answer to the first question must provide the materials that can then be used to answer the second question. It will not be enough to find what "the" best DR routine is, it will also be required to develop multiple best DR routines which will vary in duration and timing and then can be used to find which one, among the best DR routines, will result in the highest revenue increment. This approach somehow matches that used in the early days of DR in Detroit, as described by Hastings (1980), in which the system operator disposed of a number of pre-determined routines, then would superimposed the anticipated load profile of the routine to the next-day forecasted load curve, and finally would select the one "best" routine for deployment the next day, i.e. the one routine that would minimize production cost[13].

The result sought is a set of routines that will be used for valuation purpose, each of which represents the "highest" curtailment, the "lowest" and "most constant" recovery that can be achieved for a given deployment and recovery schedule. Illustration 15 introduces the terminology associated with a DR event in a graphic. It shows the typical timeline of a DR event. Routines were built based in the same sequence.

[13] Detroit was a regulated market at the time, as was a large portion of the rest of North America.

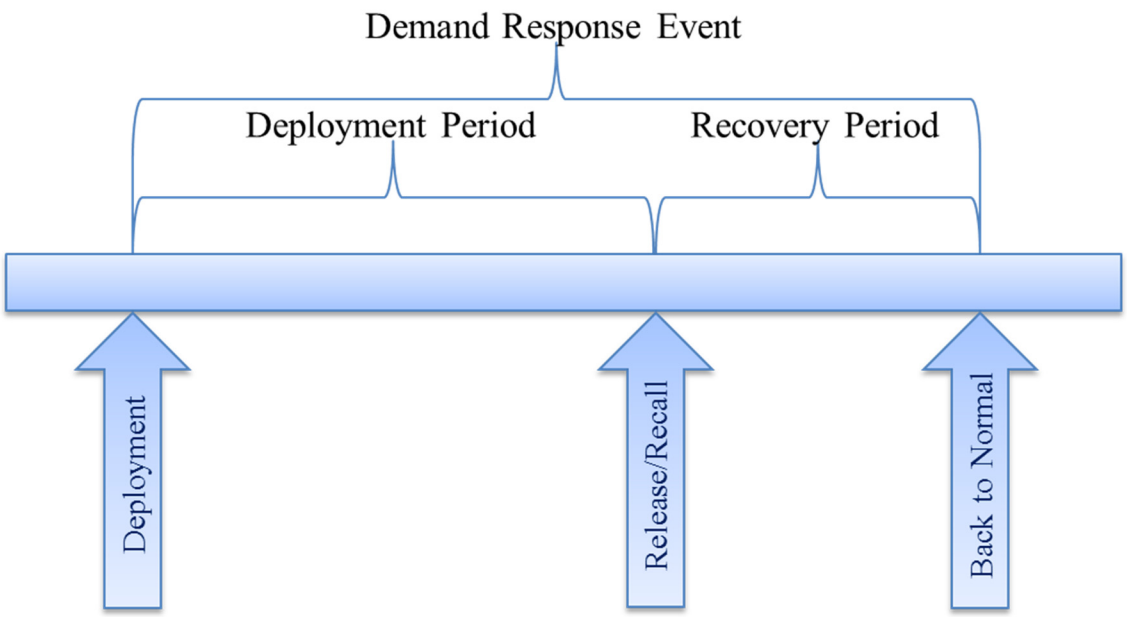


Illustration 15: Demand Response Event Timeline
Source: adapted from NERC (2011), page 11

My work in preparing this thesis is meant to be a "proof of concept". The approach to valuation and to developing the routines were not intended to perfectly replicate what a utility would do because the resources at a utility's disposal were not accessible to the average policy student (personnel, computing power, resources to purchase existing software package worth thousands of dollars). The approach will nevertheless demonstrate the feasibility of the economic dispatch concept.

The "proof of concept" approach that I developed is shown in Illustration 16 as a flow chart. The approach closely matches the approach to DLC that was introduced in Illustration 6, in Section 2.2.

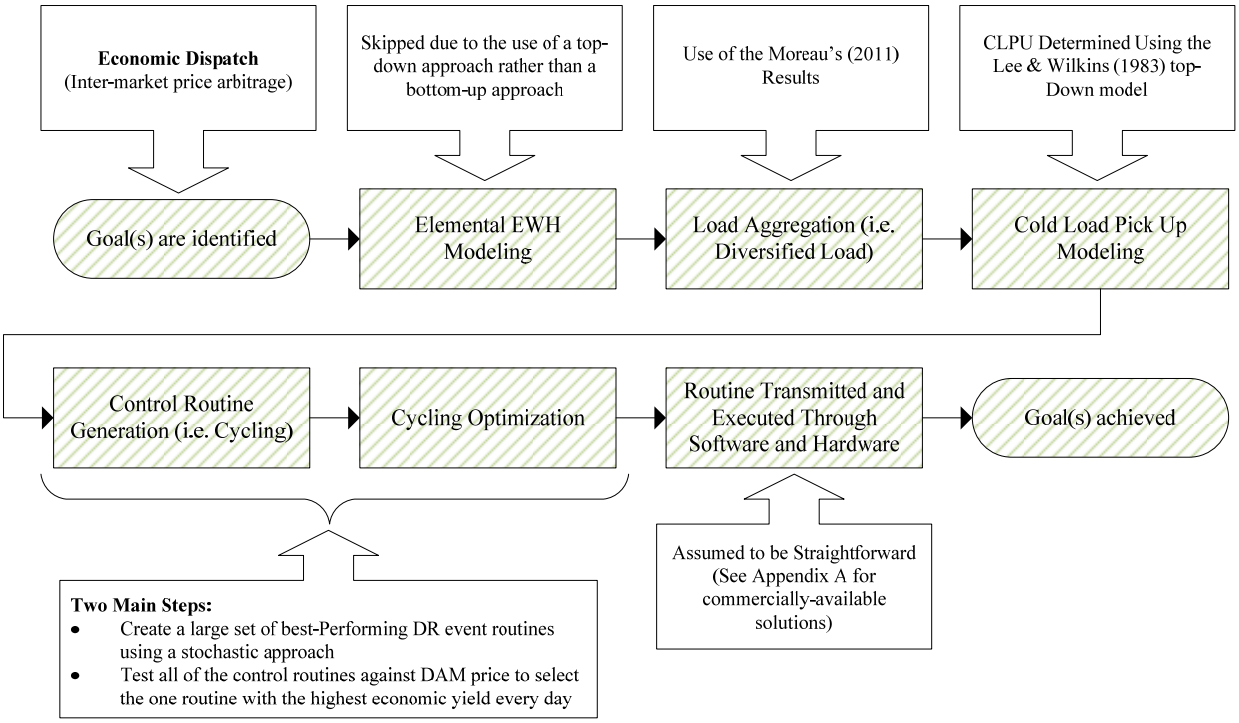


Illustration 16: Flow Chart of the Proof-of-Concept Approach

A detailed version of the algorithm shown in Illustration 16 is presented in Appendix B, Schedule 1.

The next paragraphs describe the approach to creating each a best-performing routine. Then, starting on page 79, I will explain the approach to selecting which of the DR routine has the highest economic yield when used for price arbitrage between Quebec and NYISO. The steps involved in creating a DR routine are as follows.

– **Pre-set of deployment and recovery periods:** Each routine starts with a pre-determined deployment schedule, and pre-determined recovery duration. Each routine will be developed for a specific period of the year because the period of the year determines the water inlet temperature which is known to have significant influence on the diversified load. For instance, one routine will be developed for a "60-minute deployment period, starting at 7 am, followed by a 180-min recovery in the winter when the inlet temperature is 3ºC".

- **Development of a routine through a stochastic approach:** The pool of controlled EWH in participating households was divided into ten even groups. The size of each group is assumed to be above 10,000 EWH, which is enough to ensure that the diversified load of each group will converge to a shape that closely matches that of Moreau (2011). Each routine is made of a connection/disconnection sequence with a 15-minute interval for each of the ten groups with a high likeliness of disconnection during deployment and a low likeliness of disconnection during recovery. The overall approach has been to randomly create a random routine (i.e. "one trial"), repeat the random routines 360,000 times and select the single best of the 360,000 trials as the final best DR routine for any given pre-set parameters.
- **CLPU modeling using the top-down approach developed by Lee & Wilkins (1983):** Each time a group is re-connected, the CLPU is modeled based on the empirical approach developed by Lee & Wilkins. Lee & Wilkins developed a set of equations that determine the CLPU decay curve at 15-minute intervals (See Illustration 9 in Section 2.2). All equations are a function of the total cumulated energy that was shed during the time of disconnection. The result is a net load profile for each specific group during the DR event and made of load curtailment (i.e. *negative* net load in Watts) and recovery (i.e. *positive* net load in Watts).
- **Load aggregation for all normalized EWH, then averaging again:** The 15-minute net load profiles of the ten groups are averaged into one normalized net load profile.
- **Selection of the best DR Routine:** The retained routine was the one DR routine with the "highest" curtailment, then "lowest" and "most constant" recovery. Whether a routine is better than another was determined through least mean squared error method.

During deployment, the error is the difference between the normalized net load profile and natural diversified load for each interval, thus the method rewards high curtailment. During the recovery period, an error is the difference between the normalized net load profile and zero, thereby the method rewards low recovery load. During both the deployment period and recovery period, the method naturally punishes outlying load thus favoring "constant" curves as a result. The least mean squared error method is illustrated in Appendix B, Schedule 3.

Each DR routine selected was the one with the least mean square error from a large number of random trials. The 15-minute interval net load profile for each one best DR routine were converted into 60-minute interval profiles so that they can be later cross-referenced with the 60-minute schedule of New York's DAM prices to compute the value streams.

Running a large number of random trials requires a significant amount of computing of power. Each one best routine was obtained from 360,000 trials run in Microsoft Excel 2010 using a 2.5-GHz CPU and 4.00 GB of RAM laptop. The average computation time was 30 minutes. A detailed description of the algorithm used to generate DR routines is provided in Appendix B, Schedule 2 and Schedule 3.

This simple cycling optimization method was developed for the purpose of this thesis. The results of this method suggest that it is possible to develop cycling routines that curtail the load while pacing CLPU and avoid a second peak. Furthermore, for each given group of EWH, the cycling routines typically allowed short reconnection intervals in the middle of deployment and during recovery, thereby suggesting that the likeliness of lacking hot water is low.

However, the method was meant to be a proof of concept and there are opportunities for improvements, including:

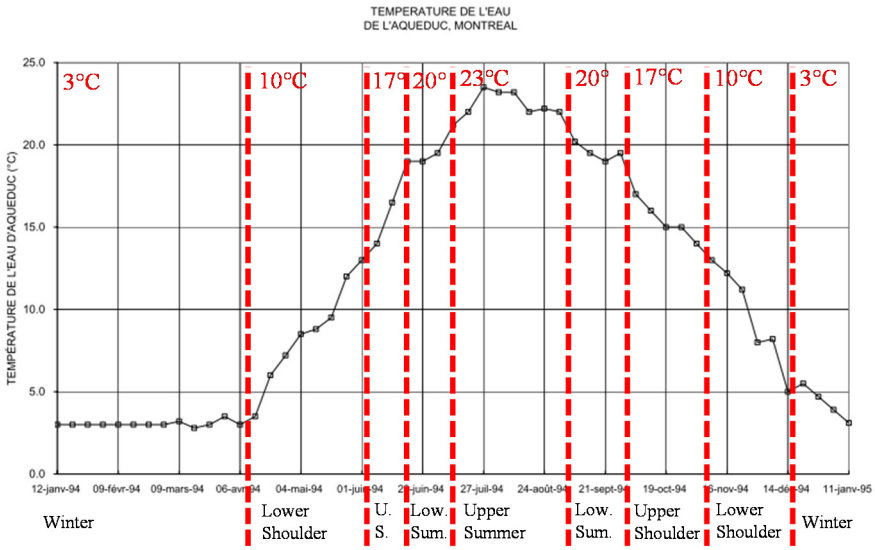
- More accurate CLPU load shape and added visibility on the probability of lacking hot water using a bottom-up approach such as the approach developed by Moreau (2011) and/or that of S. Wong et al. (2013). This, however, would require more computing power.
- Optimized computing software package for running intensive calculation, such as Matlab, compensating for the use of a "bottom-up" approach. More potent computing hardware could also be used.
- Smarter numerical analysis, perhaps through linear programing, that would converge faster, use less computing power (again, compensating for the use of a "bottom-up" approach) and obtain smoother curves as a result.

Seasonal Adjustments

The winter is when the diversified load of EWH in Quebec is the highest, and it is also when the load curtailment is most needed for adequacy purposes. The diversified load is higher in the winter because the temperature of the water entering the EWH is the lowest. However, economic dispatch of DR offers arbitrage opportunities in the summer because wholesale market prices increase the most due to high air conditioning load in New York and other neighboring summer-peaking jurisdictions.

In order to create DR routines that can be used for valuation purposes during the summer and shoulder seasons (i.e. the spring and the fall), the diversified load by Moreau (2011) had to be adjusted to account for the expected inlet water temperature. The seasons

and inlet temperature were determined through the temperature profile of Montréal municipal water. I defined five different seasons as shown in Illustration 17.



Season:	Inlet Temp.:	Dates:
Winter	3°C	Dec. 15th to April 15th
Lower Shoulder	10°C	April 16th to June 2nd; Nov. 5th to Dec. 14th
Upper Shoulder (U. S.)	17°C	June 3rd to June 22nd; Sep. 27 to Nov. 4th
Lower Summer (Low. Sum.)	20°C	June 23rd to July 13th; Sep. 4th to Sep. 26th
Upper Summer	23°C	July 14th to Sep. 3rd

Illustration 17: Inlet Water Temperature Seasons
Source: adapted from Laperrière (2008)

The winter season is the lengthiest and shows a flat inlet temperature profile. The upper shoulder seasons, as well as the lower and upper summer seasons, were divided with a smaller temperature increment because of the higher wholesale market prices during this period, which called for a higher degree of accuracy. The use of Montréal municipal water temperature data may cause a degree of inaccuracy in the results if used to design of a

province-wide program. In the future, the analysis could incorporate water inlet temperature profiles from other regions.

The adjustment of the diversified load curve is a straightforward three-step calculation. Since the diversified load is a key input of the cycling optimization method, a full set of DR routines had to be developed for each of the five seasons.

- Firstly, the winter diversified load profile by Moreau (2011) is discounted by the standby heat losses. The standby losses were assumed to be a flat amount of energy, thereby divided equally between the time intervals. standby heat loss to 2.76 kWh and 2.33 kWh per day for a 270- and a 180-L tank respectively (Lloyd & Ryan, 2008, fig. 4).
- Secondly, the remainder of the diversified load was assumed to be variable and directly proportional to the temperature gradient between the average temperature of the water inside the tank (assumed to be 50°C) and the water inlet temperature. The winter variable load was thus simply prorated. For instance, if the inlet temperature is 23°C, then the proration factor to adjust the winter variable load is equal to (50°C – 23°C)/(50°C – 3°C).
- Thirdly, the constant standby losses were added back to the prorated variable load.

Results of Performance Evaluation

The result of the cycling optimization approach described above is a wide set of routines, each of which represents the net load of one normalized EWH for a pre-set parameters during a given season. The method was used to compute 480 routines, as will be explained in page 81. The next pages will present key selected results.

Table 3 shows a number of results selected for the purpose of discussing the highest curtailment possible while controlling the pace of the recovery. The percentage showed in parenthesis, in Table 3, is the curtailment as a percentage of the full, time-coincident diversified load for one NHW.

Table 3: Highest Curtailments Obtained with Routines for One NWH

Winter Lowest Inlet temp.: 3°C	**Morning Dispatch:** Highest morning curtailment, regardless of timing or duration: **670 Wh (75%)** *Parameters: 1-hour deployment, starting at 7 am, with a 180-min recovery* *180 minute was the longest recovery period tried for a 1-h event. The same applies below.* Highest morning curtailment, with a 3-hour deployment period: **655 Wh (73%)** *Parameters: Starting at 7 am, with a 240-min recovery* *A 3-hour deployment period is the lengthiest period that was tried. A 240-min recovery is the lengthiest period that was tried for a 3-hour deployment.* The highest morning curtailments presented above coincide with the system morning peak from 7 to 8 am. **Afternoon Dispatch:** Highest afternoon curtailment, regardless of timing or duration: **701 Wh (78%)** *Parameters: 1-hour deployment, starting at 7 pm, with a 180-min recovery* Highest afternoon curtailment, with a 3-hour deployment period: **608 Wh (67%)** *Parameters: Starting at 6 pm, with a 240-min recovery. The highest curtailment happens from 7 to 8 pm.* Highest afternoon curtailment that is coincident with the system peak: **518 Wh (71%)** *Parameters: 1-hour deployment, starting at 5 pm, with a 180-min recovery* *The system afternoon peak is from 5 to 6 pm.*
Upper Summer Highest Inlet temp.: 23°C	**Morning Dispatch:** Highest morning curtailment, regardless of timing or duration: **411 Wh (73%)** *Parameters: 1-h deployment, starting at 7 am, with a 120-min recovery* *120 minute was the shortest recovery period tried for a 1-h event.* Highest morning curtailment, with a 3-hour deployment period: **361 Wh (64%)** *Parameters: Starting at 6:30 am, with a 240-min recovery. The highest curtailment happened from 7 to 8 am.* The highest morning curtailments presented above coincide with the system morning peak from 7 to 8 am. **Afternoon Dispatch:** Highest afternoon curtailment, regardless of timing or duration: **470 Wh (87%)** *Parameters: 90-min deployment, starting at 6 pm, with a 225-min recovery* Highest afternoon curtailment, with a 3-hour deployment period: **376 Wh (69%)** *Parameters: Starting at 4 pm, with a 240-min recovery. The highest curtailment happens from 6 to 7 pm.* Highest afternoon curtailment that is coincident with the system peak: **360 Wh (78%)** *Parameters: 2-hour deployment, starting at 5 pm, with a 240-min recovery.* *A 240-min recovery is the lengthiest period that was tried for a 2-hour deployment.*

The results presented in Table 3 seem intuitively sound. The highest curtailments, in absolute terms, coincide with the peaks in the diversified load. Winter curtailments are higher in absolute value then summer curtailments because the diversified load in the

winter is higher due to lower water inlet temperature and, as expected, the curtailments are similar in relative terms. As expected, shorter deployment periods yield a higher curtailment because the CLPU is easier to contain. Lengthier recovery periods allow for higher curtailment because they allow more time to deal with the CLPU. Finally, in the afternoon, the curtailment is at its highest point between 7 and 8 p.m., after the system peak. The curtailment during the system peaks remains considerable.

Illustration 18 and Illustration 19, are presented to show the results of cycling optimization in terms of containment of the CLPU. The morning and afternoon routines, in both Illustrations, were selected because they are the highest curtailments that were obtained. They are the same as those presented in Table 3. In both Illustrations, the top chart shows the net load profile for the two DR events (morning, and afternoon). The bottom chart shows the natural diversified load as per Moreau (2011), for the 180- and the 270-L tank models blended using the a 40% and 60% market share respectively. Over the natural diversified load is superimposed the curtailed diversified load for the entire population of EWH (i.e. the natural load profile + the net load profile).

Illustration 18 presents the highest curtailment obtained in the morning and in the afternoon, regardless of the timing and duration. The recovery is low and constant. The load curve for one NWH shows that the peak was displaced by the curtailment and is now higher than it was in the absence of the curtailment. If the timing is good, however, this will not matter because the wholesale price of electricity will have lowered by the time this stage will have been reached.

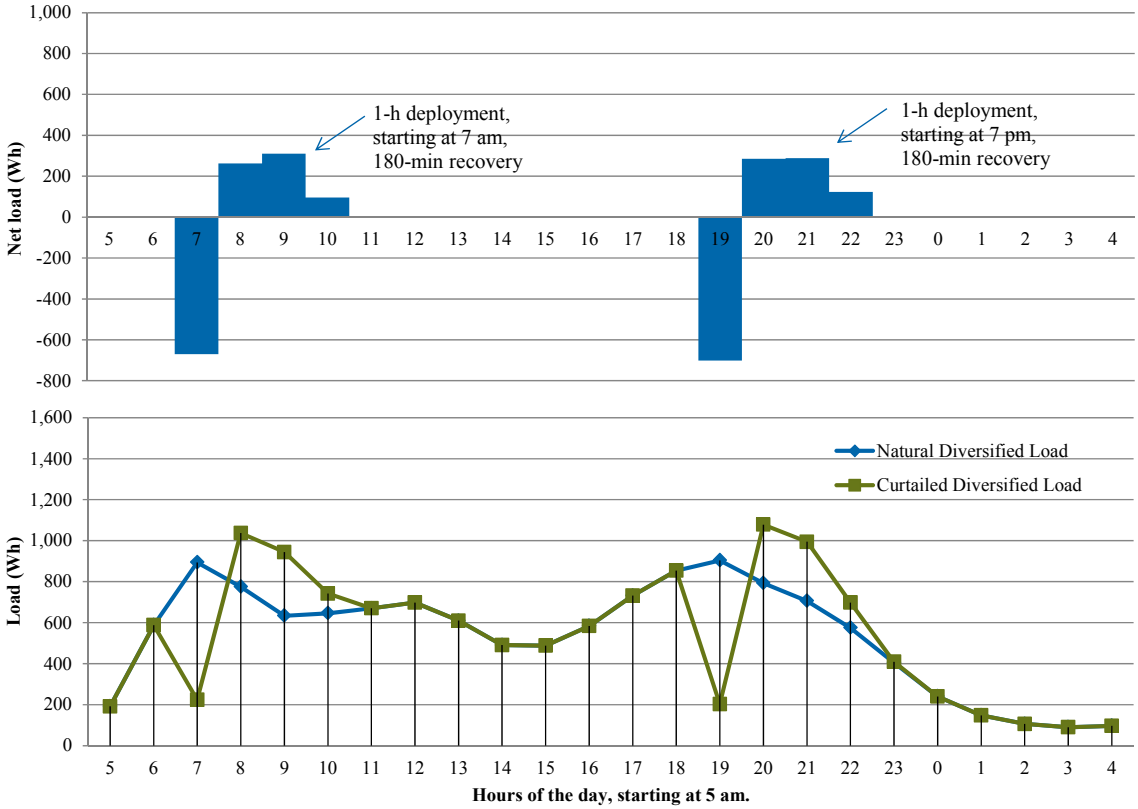


Illustration 18: Highest Winter Morning and Afternoon Curtailment, Regardless of Timing or Duration for One NWH

Illustration 19 shows the highest curtailment obtained in the morning and in the afternoon for a 3-hour deployment. The deployment duration has reached its limit. The restore load is still lower than it would have been if had been left unconstrained, but Illustration 19 still shows a restore load that is higher than that for the 1-hour curtailment and the recovery is not as constant as in Illustration 18.

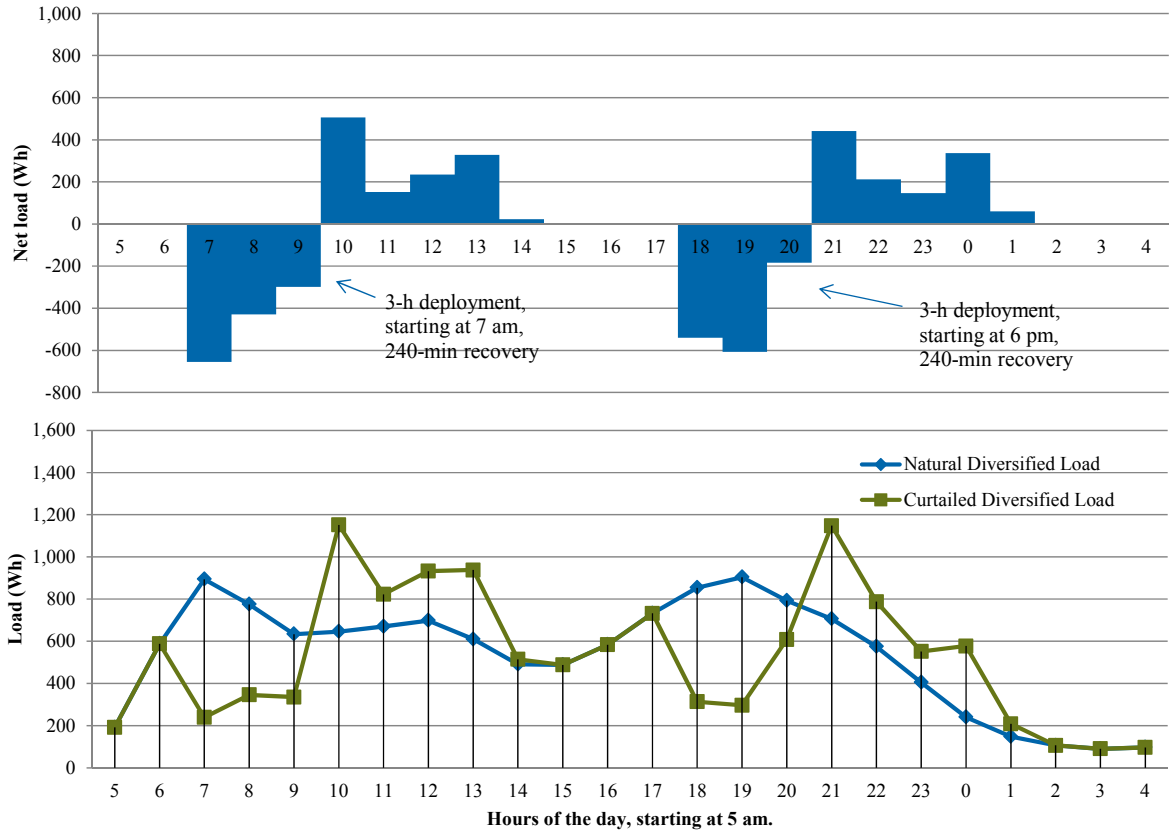


Illustration 19: Highest Winter Morning and Afternoon Curtailment, with a 3-Hour Deployment, for One NWH

Load profiles with a 15-min resolution for the same DR events shown in Illustration 18 and Illustration 19 are presented in Appendix C.

The results presented in the Table 3 and Illustration 18 and Illustration 19 constitute a few samples extracted from the hundreds of "best DR routines" that were computed and that are needed for the next steps. In the end, for the purpose of economic dispatch, the magnitude of the curtailment matters less than the timing of both the curtailment and the recovery.

Approach to Valuation

The monetary benefits achieved by economic dispatch of DR will be determined by using a large set of DR routines. The monetary benefits consist of either Quebec not buying

from NYISO during its own domestic peaks in the winter, or Quebec having more electricity to sell to NYISO during NYISO's own peaks in both winter and summer.

There are however two limits in the valuation:

- Firstly, that we use past data as if it was known in advance. In reality, there is uncertainty on what price will be observed in the following hours of a DR event. In reality, HQ production and/or HQ Distribution's traders would have to use price forecast to bid into NYISO's DAM without actually knowing what the final DAM prices will be.
- Secondly, adding a new resource to NYISO, DR in Quebec, will increase to the level of competition in NYISO's DAM, and will have some depressing effect on DAM prices compared to the historical prices observed.

Notwithstanding, the valuation method that I propose has four steps.

- **Retrieval of DAM prices from NYISO for year 2013, 2014 and 2015 inclusively (NYISO, 2016).** The "HQ generator import" LBMP was used. Prices were converted from USD to CAD historical exchange rates (daily, at noon) according to the Bank of Canada (Bank of Canada, 2016).
- **Development of a total of 480 DR routines (5 x 96) to test a wide range of possibilities in terms of inlet temperature, schedule, deployment period durations, and recovery period durations.** All possibilities are identified in Illustration 20. Each day is attributed to one of the five seasons that were identified in Illustration 17. Thereby, there is a set of 96 season-specific permutations that are available for each day. The 96 permutations were numbered from #01 to #96. They are listed in detail in Appendix D.

The 96 permutations are divided in two categories: morning events (AM events) and afternoon events (PM events). These two types of DR events were required because DR events can potentially be triggered twice per day, i.e. during the morning peak and afternoon peak.

The approach to developing DR routines was described in detail in the previous section, Section 4.1. For each DR-event option, a net load profile in Wh was developed with a 60-minute interval. In each net load profile, a negative net load represents a disconnection and a positive net load represents the energy needed to replenish the thermal storage of the NWH.

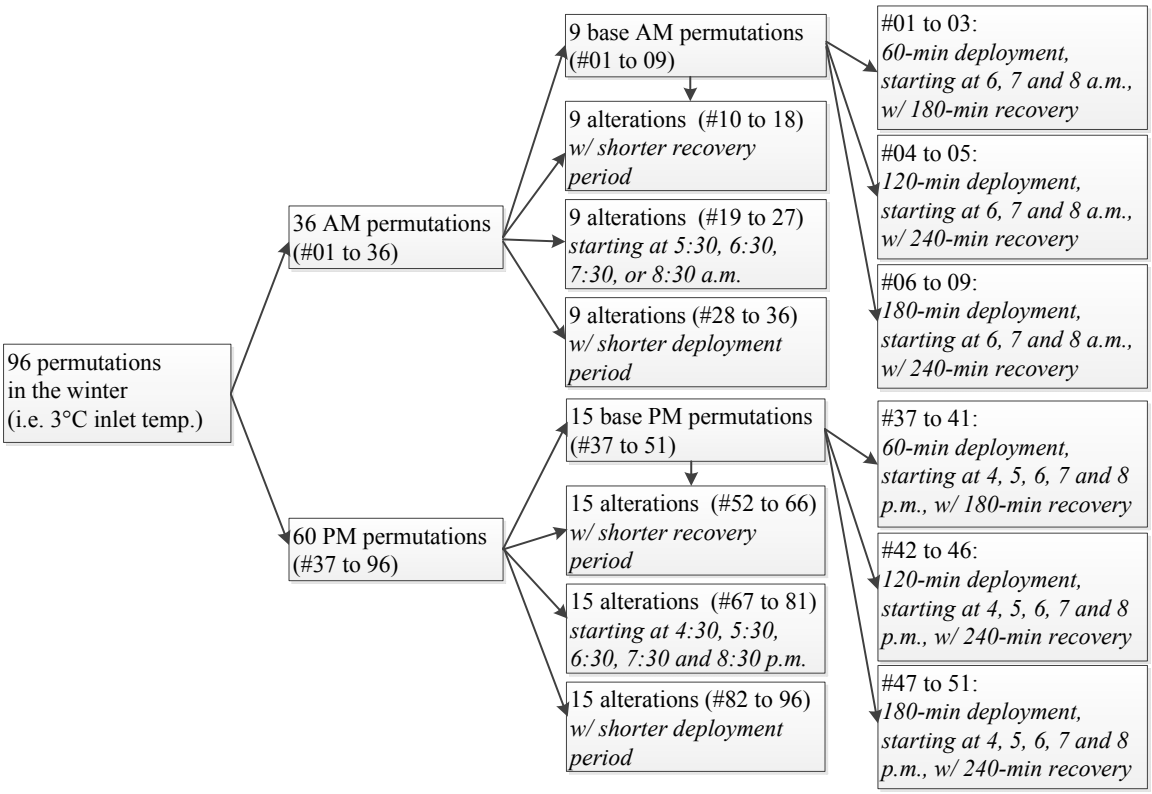


Illustration 20: Description of the 96 Winter DR routines

I had to develop 480 DR routines in total because I needed 96 winter events as in Illustration 20 as well as:

96 lower-shoulder events (i.e. inlet temperature at 10°C)
96 upper-shoulder events (i.e. inlet temperature at 17°C)
96 lower-summer events (i.e. inlet temperature at 20°C)
96 upper-summer events (i.e. inlet temperature at 23°C)

- **Selection for the best AM routine and the best PM routine for every given day.** Every disconnection makes power available to sell to NYISO. Replenishment is accomplished through buying electricity back from NYISO. Following this logic, all of the 96 DR routines are turned into an incremental revenue stream, for each day, in ($ per NWH) by multiplying the hourly net load profile (Wh per NWH) to the corresponding hourly DAM price for that day (in $/MWh). The sum of the hourly incremental revenues for every given DR routine is positive when electricity is sold to NYISO at a higher price than it is bought back. The best AM and PM routine for each given day are those that yield the highest sum of hourly incremental revenues. If none of the routines for every given day yield positive incremental revenues, then it means that none of the routines would yield an economic gain on that day and thereby no DR event should be triggered on that day.
- **Summation of the incremental revenues from all DR events opportunities thorough the year.** The valuation method what executed using MS-Excel. The NYISO DAM hourly price for 2013, 2014 and 2015 was laid out as one column and the 96 routines were superimposed on the DAM price by blocks of 24 hours.

The method relies on the four steps described above to decide which seasons are best, and which schedule, which deployment and recovery durations are optimal. Results can be

summed, sorted, categorized and analysed to shed light on what the best economic dispatch strategies are. The algorithm used is included in Appendix B, Schedule 4.

Results of Valuation

The next tables and paragraphs provide the results of the valuation method as well as their interpretation. Table 4 shows that economic dispatch of DR would yield a total of net revenues of $14.24 per year per NWH on average for the utility if all of the routines with a positive net revenue were sought after.

Table 4: Primary Results of Economic Dispatch Valuation

	2013, 2014 & 2015	Average	2013	2014	2015
Incremental revenues ($ per NWH)	$42.72	$14.24	$9.88	$21.39	$11.45
DR Event count					
Total number of potential events (AM & PM)	1,890	630	648	642	600
Total number of potential AM events	795	265	283	277	235
Total number of potential PM events	1,095	365	365	365	365

Table 4 shows the count of all of the DR events between 2013, 2014 and 2015. It makes sense to trigger a DR event if one of the 96 routines would yield positive net revenues, in the morning and/or in the afternoon, as forecasted on the day before the dispatch day using next-day DAM prices. There would be between 600 and 648 potential DR events per year. If "positive net revenue" was used as the decision factor to trigger DR, then DR would be triggered in the afternoon *every day*; and DR would be triggered in the morning two days out of three. Detailed results broken down by routine pre-sets, presented in Appendix D, show that a large number of *best* routines have a 180-min deployment and are triggered toward the end of the price peak (8 am in the morning or 7 pm in the afternoon) to ensure that the buyback is occurring during price troughs. I am making the assumption that participants in the DR program may take issue to have DR triggered systematically

once or twice every day, especially if DR events have long deployment duration, thus more likely to cause lack of hot water.

Table 5, below, provides an appreciation of the statistical distribution of the DR routines when measured by the incremental revenues that each of them may yield. The maximum yield that could have been achieved during the 2013, 2014 and 2015 period is 48.9 cents per DR event. It would have been achieved on January 27, 2014, with a 150-minute deployment starting at 6 pm with a 225-min recovery period.

Table 5: Statistical Distribution of the DR-Event Incremental Revenue Yields

	2013, 2014 & 2015	Average	2013	2014	2015
Incremental revenues ($ per NWH)	$42.72	$14.24	$9.88	$21.39	$11.45
DR Event count					
Total number of potential events (AM & PM)	1,890	630	648	642	600
Total number of potential AM events	795	265	283	277	235
Total number of potential PM events	1,095	365	365	365	365
(a) Upper limit of the top quintile (Absolute maximum revenue per event)					
Max revenue per event (AM or PM)	$48.9 c.	n/a	$21.4 c.	$48.9 c.	$26.1 c.
Max revenue per AM event	$42.0 c.	n/a	$21.4 c.	$42.0 c.	$16.7 c.
Max revenue per PM event	$48.9 c.	n/a	$18.5 c.	$48.9 c.	$26.1 c.
(b) Lower limit of the top quintile					
80th percentile (AM or PM)	$2.1 c.	n/a	$1.8 c.	$2.8 c.	$2.0 c.
80th percentile AM	$1.3 c.	n/a	$1.0 c.	$1.7 c.	$1.6 c.
80th percentile PM	$2.4 c.	n/a	$2.2 c.	$2.9 c.	$2.2 c.
(c) Mean					
50th percentile (AM or PM)	$1.0 c.	n/a	$0.9 c.	$1.0 c.	$1.2 c.
50th percentile AM events	$0.4 c.	n/a	$0.4 c.	$0.5 c.	$0.4 c.
50th percentile PM events	$1.4 c.	n/a	$1.2 c.	$1.4 c.	$1.5 c.

Table 5(b) and Table 5(c) show the 80th and the 50th percentile respectively, 2.1 cent and 1.0 cent. These two figures, in addition to the absolute maximum shown in Table 5 (b), suggest that there are few large DR routines, in terms of net revenues, and many small DR routines. By triggering a few actual event, it will be possible to obtain a large portion of

the total DR revenue potential. In addition, results in Table 5 also show that the yields of afternoon routines are typically higher than that of morning routines .

For the sake of discussion, a threshold was drawn at the 80th percentile, or $2.1 cents per event per NWH. This threshold is an arbitrary value based on Pareto principle. The Pareto principle is a common preliminary assumption in business which stipulates that about 80% of the impacts typically originate from 20% of the causes. The use of a basic decision rule to determine whether to pursue a DR opportunity, such as using a minimum forecasted yield threshold, appears realistic from an operational standpoint. Table 6 present the revenues that could have been achieved if operators had triggered DR only if the forecasted revenues were to be above the 80th-percentile threshold, 2.1 cent.

Table 6: Cumulative Revenues from the Top Quintile

Incremental revenue from the top quintile (i.e. only the 20% most lucrative events are called)

Total revenues for events above $2.1 cent	$29.84	$9.95	$5.42	$17.35	$7.06
Number of events (AM or PM)	378	126	101	160	117
Number of AM events	115	53	24	51	40
Number of PM events	263	73	77	109	77

The number of events, as presented Table 6, went from 648 events per year to 160 events per year, which is likely to seem more palatable to the participants. Table 6 also show that PM event outnumber and AM event with a ratio of 2 to 1. The Pareto rule was relatively accurate in this particular instance because triggering only the top-20% DR-routines would allow the accrual of $9.95 per year per NHW (yearly average), or about 70% of the full potential (not so far from 80%).

The distribution of the DR opportunities was charted in the form of a cumulative profile from the 100th percentile to the 0th percentile in Illustration 21. For instance, if only the top 10% of the DR opportunities were triggered (i.e. the 90th percentile), 57% of the potential could be achieved. Similarly, if 50% of the opportunities were triggered, then 89% of the potential would be realized.

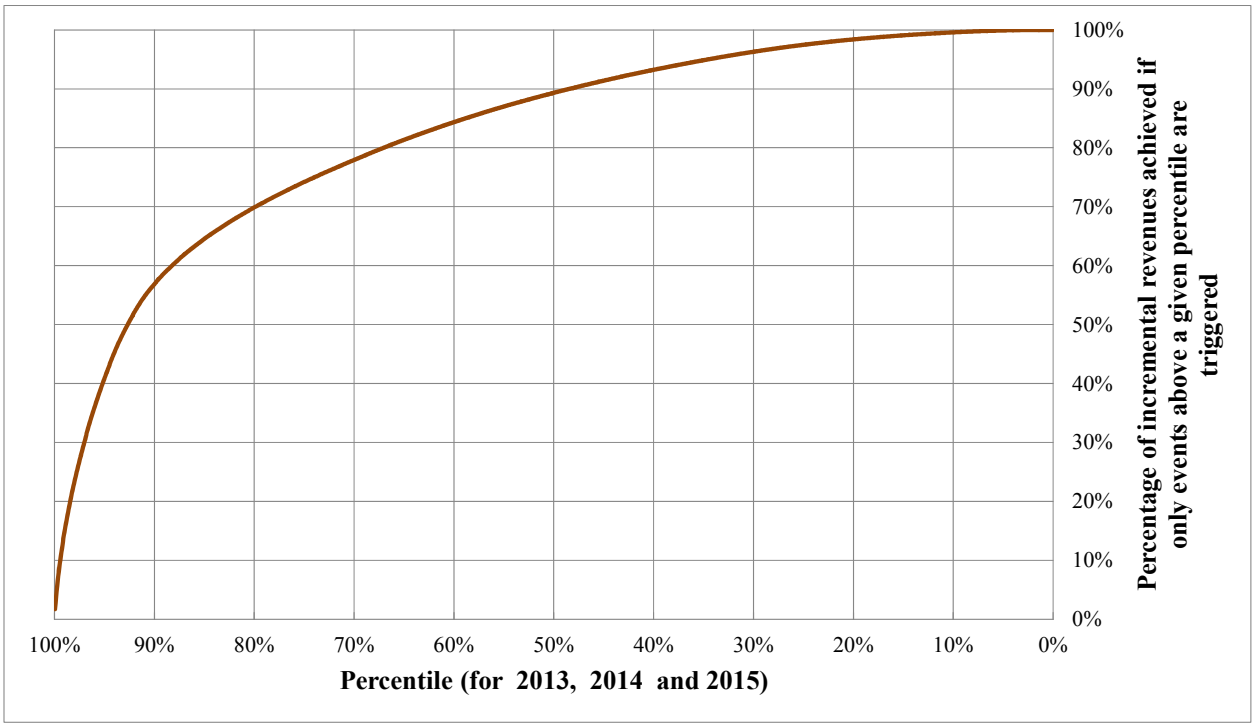


Illustration 21: Cumulative Distribution of Incremental Revenues based on Yield per DR Event

From that point onward in this section, the results shown will be for the top quintile only. The true decision threshold should be determined in the future through testing the perceived tolerance of prospective participants to the number of DR events per year. This could be achieved through customer consultation (e.g. surveying and focus groups). It is expected that the final threshold will lie somewhere between the 60th and the 95th percentile, and thus the use of the top quintile is representative of the final program design.

The use of a threshold to decide whether trigger DR and when to trigger the DR event is an example of the use of option value of DR under the "load shifting/displacement" model as laid out by Sezgen et al. (2005, fig. 14) of Ernest Orlando Lawrence Berkeley National Laboratory. The threshold is the strike price above which the DR event is to yield its payoff. For instance, if the strike price were "$0", then all the routines that would yield positive net revenues would be triggered. The option value theory could be used in the future to make improvement on the decision model, and in particular to maximize seasonal payoff based on a maximum number of DR events per year. The system operator would use an adaptive strike price that would evolve based on total DR events triggered to date, and likeliness of more and better DR opportunities to present themselves during the remainder of the year.

Table 7 presents statistics on what the best routines were. Only top-quintile DR routines are shown. The detailed top-quintile result breakdown for each of the 96 permutations x 5 seasons in 2013, 2014 and 2015 can be found in Appendix E.

Table 7(a) shows that a majority of the most lucrative DR events would occur in the winter, when the curtailment potential is the steepest due to the cold inlet water temperature. Table 7(b) shows that longer DR events, despite the lower level of curtailment, are typically better than shorter DR events.

Table 7: Statistics on Top-Quintile DR Events, in 2013, 2014 and 2015

(a) Breakdown of DR events -- per season

	Total	Winter	Shoulder	Summer
Number of events (AM or PM)	378	307	62	9
Number of AM events	115	111	4	0
Number of PM events	263	196	58	9

(b) Breakdown of DR events -- per deployment duration

	Total	45 min	60 min	90 min	120 min	150 min	180 min
Number of events (AM or PM)	378	0	0	0	5	134	239
Number of AM events	115	0	0	0	1	0	114
Number of PM events	263	0	0	0	4	134	125

(c) Breakdown of DR events -- per start time

	Total	5:30	6:00	6:30	7:00	7:30	8:00	8:30
Number of AM events	115	0	11	48	37	0	19	0

	Total	15:30	16:00	16:30	17:00	17:30	18:00	18:30
Number of PM events	263	1	3	26	47	1	150	8

19:00	19:30	20:00	20:30
18	5	4	0

(d) Breakdown of DR events -- per week day

	Total	Sunday	Monday	Tuesday	Wedn'day	Thursday	Friday	Saturday
Number of events (AM or PM)	378	30	68	71	60	59	55	35
Number of AM events	115	6	19	23	18	20	19	10
Number of PM events	263	24	49	48	42	39	36	25

Table 9(c) does not show a clear pattern in term of "best" start time in the morning. The event counts are scattered across the spectrum. However, 6 p.m. (18:00) is the start time of more than half of the afternoon DR events, and nearly half of all DR events in the top quintile. The period from 6 p.m. to 9 p.m. is when the diversified load of the EWH is the highest. It is also coincident with the NYISO DAM price peak. DAM prices go down significantly after 9 p.m. Table 9(b) suggest that a top-quintile DR event is twice as likely to occur on a business day then on the weekend.

In summary, there are two value streams that DLC of electric water heater would allow Hydro-Quebec to achieve. The first one is due to the ability of DLC to provide emergency load curtailment. As seen in Section 4.1, this value stream is worth $89.51 per year per

NHW with no escalation rate (in real $). The second one is economic dispatch of DLC. As seen in the discussions above, this value stream is worth $9.95 per year per NHW on average in 2015. The assumption was made that the same incremental revenues would be accrued in the future, pegged to the escalation of electricity price in the U.S. in real $ according to the Department of Energy's Annual Energy Outlook (2015).

The next Chapter will seek to estimate what potential can be anticipated from a province-wide DLC program deployment. The emergency curtailment will be the main driver for determining the potential since it is has a larger value stream than that of economic dispatch.

Chapter 5. Market Potential

This Chapter consists of presenting the approach to and results of market potential modeling for DLC of electric water heaters in the residential sector in Quebec. Market potential is a defining aspect of the value of DR because it is an indicator of whether this particular technological solution is worth investing more time and effort to develop, and carry from the conceptual level, presented here, to actual implementation. It is common for DSM/DR program administrators to use potential as one of the main criteria to decide whether or not prioritise certain demand-side measures or technological solutions over others in its strategic planning.

There are four types of DR potential: technical potential, economic potential, achievable potential and program potential. Each one of these potential types is a subset of the one listed before. The technical potential is the impact possible if all solutions were deployed immediately. The economic potential is the impact if the technology or program is economically feasible. The achievable potential is the impact that can be realistically expected assuming the most aggressive program approach possible. The program potential is the impact given specific funding level and policy design (NAPEE, 2007a, p. 2.4).

Section 5.1 will present the technical and economic potentials, and Section 5.2 will present the achievable and program potential.

5.1 Technical and Economic Potential

For all intents and purposes, for DLC of electric water heaters the economic potential will be deemed equal to the technical potential based on the assumption that the solution is economically feasible. This assumption will be successfully demonstrated in Section 6.2.

Approach to Determining the Technical and Economic Potential

The diversified load curve for one NWH, expected CLPU curve after a curtailment and approach to mitigating CLPU are all key assumptions that will be needed to compute the emergency curtailment potential in the province. The main parameter that is not settled yet is the total number of households, or "participants", who would enroll into the DR program. There are 3,857,782 residential households (i.e. rate classes: Tariff D, DM and DT) in Quebec (HQ, 2015b). The level of penetration of electric water heating in Quebec is 94% (NRCan, 2010) thereby there are 3,626,315 EWH in the province, assuming one EWH per household[14]. The economic potential, however, cannot be computed simply by multiplying the curtailment possible for one NWH by the total number of households. Instead, the following approach had to be followed:

- **Selection of a critical system-peak day:** The day with the highest peak was selected from the 2013 hourly domestic load data unveiled by HQ Distribution (HQD, 2014). January 23, 2013 was selected because it was the day of the worst peak of the year, 36,219 MWh/h between 6 and 7 p.m.
- **Creation of emergency DR routines:** Two routines were created for an illustrative purpose; one for the morning and one for the afternoon peak. The result of the routine is a net load profile for one NWH. The emergency event was made of 4-hour deployment with 4-hour recovery. The morning routine was scheduled to start at 6 a.m. to cover the entire morning system peak, and the afternoon routine was scheduled to start at 4 p.m. to cover the entire afternoon peak. The approach was modeled on that of Moreau (2011). As per Moreau, the EWH were to be reconnected gradually during a

[14] In reality, some households have two water tanks and a few may have tank-free electric water heaters. The data to make the correction is not available, but it is assumed to introduce a negligible bias.

period lasting three hours, which made the recovery period last four hours in total. The net load profiles were traced using a similar approach than the approach described in Section 4.1. The pool of EWHs was assumed to be divided in 10 equally-size groups. The entire pool of EWHs is disconnected during the deployment period, and then, beyond the deployment period, the groups are reconnected at equal interval over the course of 3 hours. The CLPU was modeled based on Lee & Wilkins top-down empirical equations (1983).

- **Determination of the curtailed system curve:** The curtailed system demand curve is essentially the natural system demand curve (i.e. the hourly domestic demand) minus the hourly net load profile for the entire of the pool of EWH being controlled. The net load profile is the unitary net load profile (i.e. for one NWH) multiplied by the number of participants in the pool.
- **Determination of the maximal emergency curtailment possible without generating a second peak due to the CLPU:** The maximum emergency curtailment possible is the technical and economic potential that is being sought for. The main limitation that precludes from triggering all of the 3,626,315 EWH in the province is the peak created by the CLPU during the recovery period. As the number of EWH being disconnected grow, so does the peak created by the CLPU. The maximal curtailment possible was determined through trials and error. As a counter-example, Illustration 22 shows what would happen if all of the EWH in the province were disconnected and then reconnected as per the emergency DR routine described above.

Illustration 22 demonstrates that it would be ill-advised to disconnect all of the EWH in the province, despite the gradual reconnection over a period of four hours. The peak created by the CLPU would be higher than the original peak that the disconnection was intended to offset in the first place by 1,250 MWh/h. The top part of Illustration 22 is the net load profile for all of the 3,626,315 EWH. The bottom part of Illustration 22 shows both the natural system load profile for January 23, and the curtailed system load (both are hourly integration).

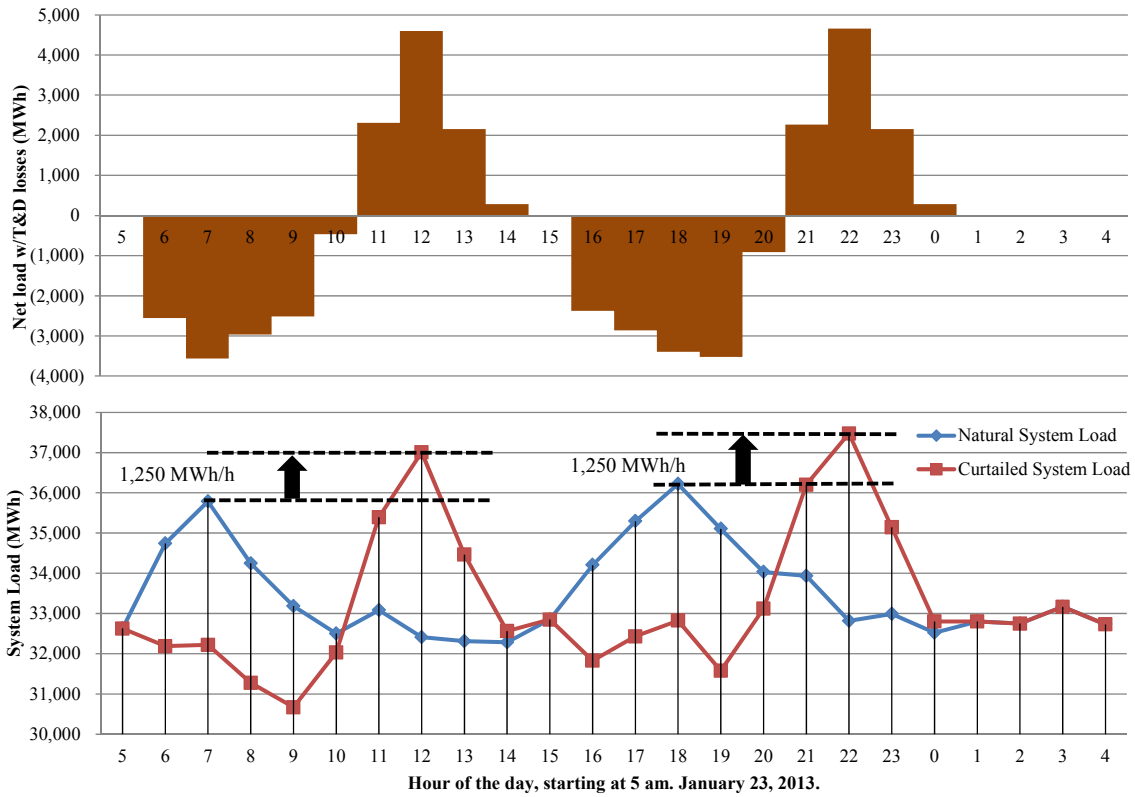


Illustration 22: Impact of an Emergency Curtailment of all EWH in Quebec

Results of the Technical and Economic Potential Modeling

Illustration 23, below, shows that the maximum curtailment is reached if a total number of 1,500,000 EWH were to be disconnected. The maximum curtailment achieved is approximately 1,450 MWh/h in the morning and the same in the afternoon[15].

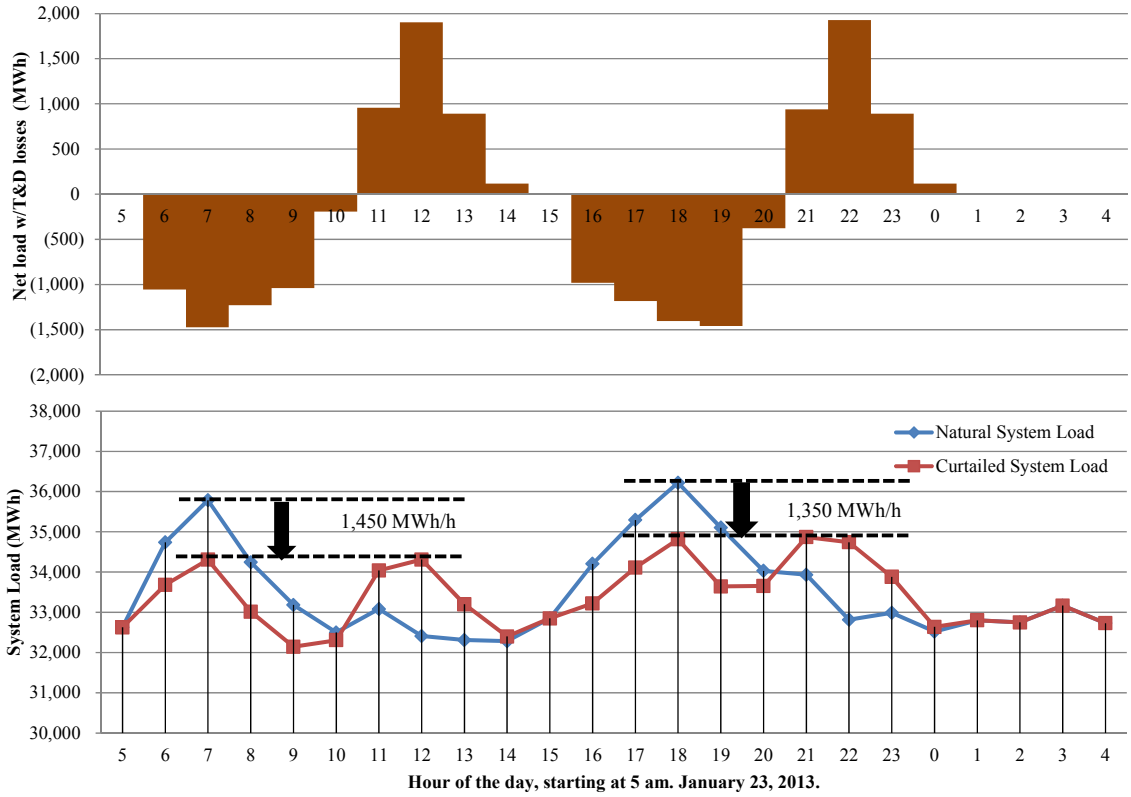


Illustration 23: Maximum Emergency Curtailment (1,500,000 EWHs)

Above 1.5 million disconnections, the second peak, despite being conveniently shifted *after* the natural system peak during the system load ramp-down, would be higher than the primary curtailed peak. If more than 1.5 million disconnections were to happen at the same time, the total curtailment would actually be lower. It would be ill-advised to aim at

[15] The DR events shown in Illustration 22, as well as in Illustration 23 and Illustration 24, are emergency events intended to happen only in very rare occasions. In addition, two events were charted in the same graph only as an example. Two emergency events are unlikely to be triggered on the same day.

controlling all of the EWHs in Quebec because for every one EWH controlled above 1.5 million EWH, the utility would incur the costs of installing the control equipment, but would not accrue any gain related with system capacity adequacy.

Anywhere below 1.5 million disconnections, however, the peak created by the CLPU is not an issue. For instance, Illustration 24 demonstrates that the CLPU is not a preoccupation for small number of EWH (in this example, a number of 100,000 EWH was used). The natural ramp-down of the system load makes up for the CLPU-induced peak by a large margin.

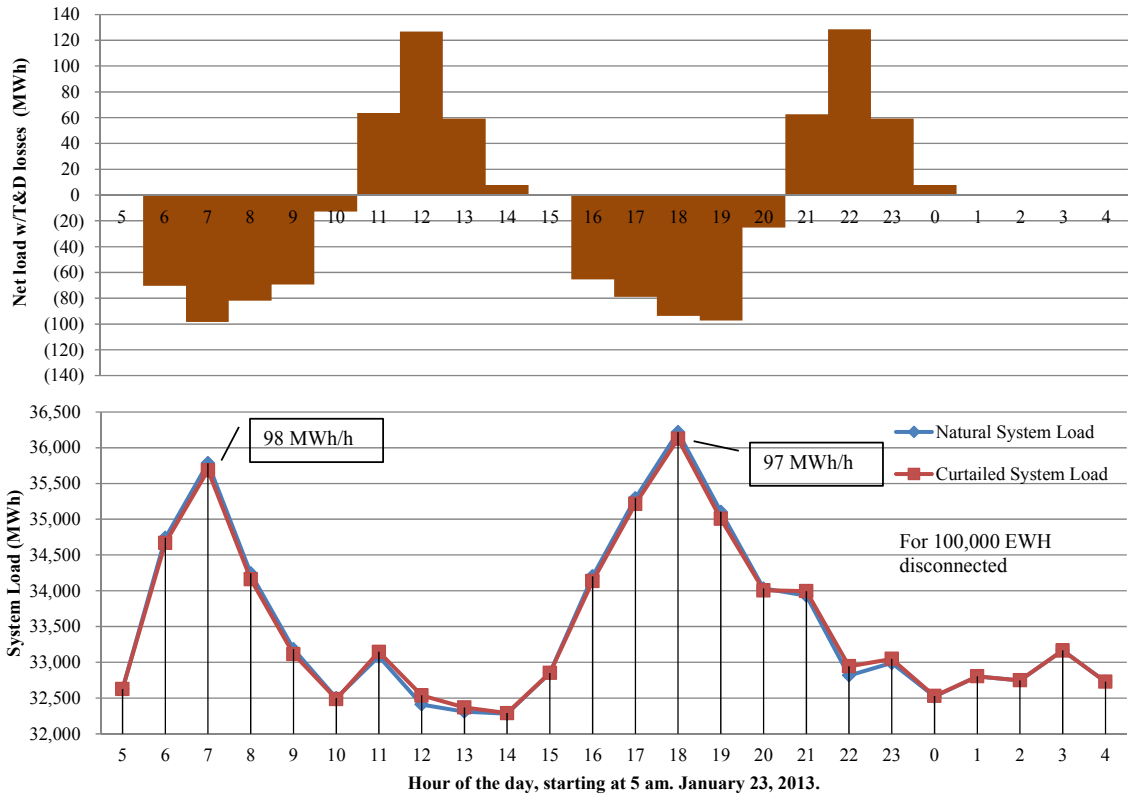


Illustration 24: Example of an Emergency Curtailment With Pool of EWH Smaller than 1.5 Million EWH (i.e. 100,000)

The unitary curtailment in Illustration 24, approximately 1.0 kWh/h per NWH, is higher than the performance suggested in Section 4.1, 0.7 kW. There are three reasons for

this. Firstly, 0.7 kW does not include T&D losses, while 1.0 kWh/h does (T&D losses in Quebec is 7.9% as discussed earlier). Secondly, the units are not exactly the same. 1 kWh/h is an integrated hourly value while 0.7 kW was determined using a higher degree of granularity (i.e. 15-minute interval). Thirdly, the peak on this particular day, January 23, 2013, happened to be coincident with that of the NWH diversified load profile. In reality, such coincidence will not happen every day. Thereby, because of the low level of resolution and because of the possibility of the curtailment and the peak not to be coincident, it is prudent to de-rate the curtailment and assume a curtailment of 0.7 kW per participant in the DR program without T&D losses (or 0.76 kW with T&D losses).

The technical and economic potential is thereby 1,450 MW including T&D losses if 1.5 million participants were to enroll, as was shown in Illustration 23. This number of participant represents 39% of all households in Quebec. As a participation rate, this is unrealistically high because the DR program will be most likely be an "opt-in program"; i.e. households would enroll on a voluntary basis. There are many constraints that would preclude that number to be reached; for instance, the tenant households who are not the owner of the EWH, reluctance of households to have the utility gain control over anything inside of ones' dwelling, concern over *perceived* health hazards caused by HQ Distribution's new smart meters, time and effort involved in subscribing to the program, and lack of interest. Furthermore, although DR program administrator typically seek to broadcast information about their programs in an effective manner; it is generally impossible to ensure full coverage of any given population let alone convince everyone to sign up for any given program. The purpose of the next Section is to determine what a realistic (i.e. achievable) participation rate could be in Quebec.

5.2 Achievable and Program Potential

The achievable potential and the program potential are essentially two different impact scenarios. The former is the impact scenario with unlimited funding and the latter accounts for the program administrator's budgetary constraints. Since the program administrator's budget is an unknown, this section will develop three different scenarios: basic, moderate and maximum achievable. The program potential that could be targeted by the program administrator is assumed to be somewhere between the basic and the maximum achievable scenario.

They key variable that remains to be estimated for each one of the three scenarios is the participation rate for each scenario.

Approach to Determining the Achievable and Program Potential

There are a number of techniques available to determine the participation rate in a DR program. Table 8 introduces the main approaches.

Table 8: Methodological Options to Estimate the Achievable Potential

Technique Name	Description	Benefits	Drawbacks
Delphi panel	Participation rate is estimated by a panel of experts	– Simple – Quick	– Require access to many DR program experts – Not based on any evidence
Benchmarking	Participation rate determined through comparing with that in other jurisdictions	– Simple – Quick – Uses real data from other markets	– Does not factor in parameters such as energy prices, market and regulatory conditions, incentive size, etc.
Customer survey	Survey the target energy end-users on the level of interest in participating	– Factors in the opinions and circumstances of the program	– Resource-intensive – Risk of biases in the responses (e.g. self-selection bias)
Economic threshold	Participation rate depend a minimal level of incentive or a level of financial indicator	– Factors in aspects of the program design – Systematic and evidence-based approach	– Requires simplification of real-world decision – Ignores non-economic parameters influencing participation
Choice model	Statistical technique used to adjust participation rates obtained from customer survey and/or from benchmarking data to certain key parameters	– Systematic and evidence-based approach	– Most resource- and data-intensive

Source: Lui et al. (2015), Goldman et al. (2005), and Faruqui et al. (2014)

Since there is no pre-existing residential DLC experience in Quebec, "benchmarking" was selected as the most appropriate approach under the circumstances. The participation rate was estimated through the use of the data retrieved during 2012 FERC survey on DR and smart meters (2012). As part of the FERC survey, program administrators provided the number of participants enrolled in their DR program(s).

The overall sample from the FERC survey was screened to keep only the DLC programs aimed at the residential sector. The two following program types were also left in the sample because of their similarities with DLC: "Critical peak pricing with DLC", and "emergency demand response". All DLC programs were considered regardless at what energy use each program was intended to control, like for instance air conditioning, electric hot water, space heating, ventilation, refrigeration, and thermal storage. In other words, it was assumed that households are equally inclined to participate in DLC regardless of what appliance is being controlled. All of the "mandatory" DLC programs and the "opt-out"[16] DLC programs were removed from the sample.

The remaining number of programs after the screening was 245. They spanned across 38 states. It was assumed that a large majority of utilities that do offer a residential DLC program in in the United States self-selected themselves in the survey, which made the survey close to a census of all residential DLC programs. The tally of participants in each of the 38 states was divided by the number of residential customers in each state for 2011 (the year the FERC survey was carried out) as found in the yearly statistics on power consumption in the United States published by the Energy Information Administration

[16] The "mandatory" and the "opt-out" programs are those programs in which all households are enrolled in the program. An "opt-out program" differs from the "mandatory" program in that households can "opt-out" if they so wish as long as they formally follow an "opt out" procedure.

(EIA, 2015a). The range of participation rates for the 38 states spanned from 0.01% in Washington State to 52.10% in South Dakota.

Results of the Achievable Potential Modeling

The participation scenarios were then defined as follows:

- **Lower achievable scenario:** 50th-percentile participation rate according to the 2012 FERC survey on DR.
- **Moderate scenario:** 100,000 participants, which is the number of participants that HQD filed with the energy regulator (HQD, 2015e).
- **Upper achievable scenario:** 80th-percentile participation rate according to the 2012 FERC survey on DR.

A range that spans between the 50th and the 80th percentile was assumed to be a realistic range for HQD to set its target. Firstly, HQD would deploy the DLC program in the entire province, which is not the case in a majority of the states because the service territory of utilities in the US typically only covers part of a state. Secondly, HQD's new AMI is being deployed in every corners of the province. Not all of the 38 states have a full AMI coverage as Quebec shortly will have. Without an AMI, while it still is possible to do DLC through broadband communication, the absence of AMI makes it nevertheless more challenging.

Thirdly, EWH are ubiquitous in Quebec's households and this is a homogeneous appliance relative to that of air-conditioning, space heating and others. As a result, a larger percentage of dwellings will be compatible with the program than they would be for programs that aim at any other thermostatically-controlled appliances. Fourthly, from a marketing standpoint, HQD benefits from a greater degree of visibility than that for utilities in most of the states because Quebecers have an emotional attachment to their provincial

utility. Broadcasting information about the program should therefore be more effective that it would be in most other jurisdictions.

Consequently, HQD should aim to realize a participation that would put Quebec at least above the 50th percentile. However, since DLC still is incipient in the province, obtaining a high participation rate with a first DLC program will be challenging. The 80th percentile in North America seems to be appropriate stretch target.

The analysis of the 2012 FERC survey data led to conclude that the 50th-percentile participation rate and 80th-percentile participation rate in the United States are 1.78% and 4.44%, respectively. Table 9 presents the implications of these results for the three achievable-potential scenarios, as well as some other results from Section 5.1.

Table 9: Recapitulative Table of Market Potential

Scenario	Participation	Impact of Emergency Curtailment
All EWH being disconnected	**3,626,315 EWH** or 94% of all households, which is the % of penetration of EWH	***Negative* 1,250 MWh/h** because of the second peak caused by the CLPU
Technical & economic potential	**1,500,000 EWH** or 39% of all households, which is the limit imposed by the CLPU	**1,350 MWh/h** including T&D losses and assuming excellent coincidence of curtailment with the system peak as observed on January 23, 2013.
Upper achievable potential	**171,354 EWH** or a participation rate of 4.44% of all households, which corresponds to the 80th percentile of that for residential DLC programs in the U.S.	**130.1 MW** including T&D losses Avoided planning reserve margin: **14.4 MW** The CLPU is not a concern under 1.5 million disconnections.
Moderate potential	**100,000 EWH** (or a participation rate of 2.59% of all households) which corresponds to the number of participants that HQD filed with the Régie de l'énergie in July 2015	**75.9 MW** including T&D losses Avoided planning reserve margin: **8.4 MW** The CLPU is not a concern under 1.5 million disconnections.
Lower achievable potential	**68,490 EWH** or a participation rate of 1.78% of all households, which corresponds to the 50th percentile (the median) of that for residential DLC programs in the U.S.	**52.0 MW** including T&D losses Avoided planning reserve margin: **5.8 MW** The CLPU is not a concern under 1.5 million disconnections.

Table 9 also included the avoided planning reserve margin that would be accrued as a result of demonstrating an ability to shed the anticipated system peak. HQ Distribution uses 11.1% for avoided planning reserve margin[17].

[17] Ratio between the reserve margin and anticipated system peak from 2020 to 2023 (HQD, 2013, p. 28).

In Table 9, it is assumed that the economic potential is equivalent to the technical potential, which is true if the technical potential for residential DLC of electric water heaters is economically feasible. The next Chapter entails the verification of this assumption.

Chapter 6. Cost-Benefit Analysis

Chapter 6 consists of presenting the results of the cost-benefit analysis (CBA)[18] of the DLC program in Quebec. Chapter 6 is structured as follows: Section 6.1 presents the framework used for CBA analysis and exposes all of the assumptions that were made with regard to the benefits and costs of the proposed DR program. Section 6.2 unveils the results and Section 6.3 discusses the sensitivity of the results.

6.1 Approach to Cost-Benefit Analysis

The CBA was carried out in accordance with a study contracted by the FERC to develop a framework for economic analysis of DR programs (Woolf et al., 2013). I selected this specific framework because of its relevance with the authoritative nature of the FERC and stature of the authors involved in the study.

The framework developed by the FERC aligns with the California standard practice manual (SPM) of economic analysis of demand-side resources (CPUC, 2001). The SPM is the classical approach to CBA for DSM resources. The SPM looks at economic benefits and economic costs from the perspective of multiple stakeholders. Same as the SPM, the FERC Framework uses five standard CBA tests, which are:

- **Participant cost test (PCT):** The PCT looks at the value of participating in the DR program for the household who decide to enroll. The PCT tells whether benefits will outweigh costs from the perspective of the households who will decide to enroll in the program.
- **Program administrator cost test (PAC):** The PAC takes the view of the DSM program administrator. The PACT tells whether the total cost of service of a price-

[18] Cost-benefit analysis is the wording used in the academic policy analysis discipline. However, DSM-program experts typically use "cost-effectiveness" analysis instead.

regulated utility will decrease or increase as a result of pursuing the DR programs. The PAC is often used as a measure of the performance of a program administrator.

- R**ate-impact measure test (RIM):** The RIM takes the perspective of the non-participants (i.e. those ratepayers who get to fund the program through their rate but decide not to benefit from the program by participating). The RIM tells whether the electricity rates will increase, on average, as a result of the DR program. The only difference between the RIM and the PACT is that the RIM accounts for the lost revenues incurred by the regulated utility in the event that the utility collects less electricity from its customers through the electricity bills. The RIM is the most stringent of the tests. A failed RIM indicates that the electricity rates will increase in the short term as a result of the program, which amounts to a form of cross-subsidy between non-participants toward participants.
- **Total resource cost test (TRC):** The TRC looks at the economics from the perspective of total power system resources. The TRC determines whether the resource cost of the DR alternative is higher than that for the business-as-usual scenario (i.e. typically a supply-side investment in generation capacity).
- **Societal cost test (SCT):** The SCT takes a comprehensive economic point of view as observed by the society as a whole by including all of the costs, even those incurred by bystanders (i.e. economic externalities).

Typically, the viability of DR programs (i.e. whether the DR programs are "economically feasible") is measured using the TRC. This is not on the account of the superiority of the TRC, but only that the TRC is used as a screening tool to distinguish economic potential from technical potential. During further policy design stages, the good

practice according to the FERC is to perform all tests before making any final decision on any given program to account for all perspective.

HQ Distribution and the Régie de l'énergie typically use primarily the TRC (in French: *Test to coût total en resource* or TCTR) to make decision, but always compute and publish the PCT (in French: *test du participant* or TP) as well as the RIM (in French: *test de la neutralité tarifaire*).

The best practice of economic CBA is to make a comprehensive list of all of the economic cost and a comprehensive list of all of the economic benefits. Fortunately, the approach to developing the FERC Framework was compliant with this best practice.

Table 10 is a list of all costs and benefits that may be expected from DR programs in general according to the study commissioned by the FERC. Each cost item and benefit item in Table 10 was attributed to one of the five standard CBA tests.

Table 10: Comprehensive List of Possible Costs and Benefits of DR Program

Cash-flows	**PCT** – Participant cost test	**RIM** – Rate-impact measure test	**PAC** – Program Admin. Cost test	**TRC** – Total res-source cost test	**SCT**– Societal Cost test
Benefit					
Avoided capacity costs	--	Yes	Yes	Yes	Yes
Avoided energy costs	--	Yes	Yes	Yes	Yes
Avoided transmission and distribution costs	--	Yes	Yes	Yes	Yes
Avoided ancillary service cost	--	Yes	Yes	Yes	Yes
Revenues from wholesale DR programs	--	Yes	Yes	Yes	--
Market-price suppression effect	--	Yes	Yes	Yes	--
Avoided environmental compliance costs	--	Yes	Yes	Yes	Yes
Avoided environmental externalities	--	--	--	--	Yes
Participant bill savings	Yes	--	--	--	--
Financial incentive to participant	Yes	--	--	--	--
Tax credits	Yes	--	--	Yes	--
Other benefits	Depends on nature of benefit				
Cost					
Program administrator expenses	--	Yes	Yes	Yes	Yes
Program administrator capital cost	--	Yes	Yes	Yes	Yes
Financial incentive for participant	--	Yes	Yes	--	--
DR measure cost, program administrator contribution	--	Yes	Yes	Yes	Yes
DR measure cost, participant contribution	Yes	--	--	Yes	Yes
Participant transaction cost	Yes	--	--	Yes	Yes
Participant value of lost service	Yes	--	--	Yes	Yes
Increased energy consumption	--	Yes	Yes	Yes	Yes
Lost revenues to the utility	--	Yes	--	--	--
Environmental compliance costs	--	Yes	Yes	Yes	Yes
Environmental externalities	--	--	--	--	Yes

Source: Woolf et al. (2013)

All of the benefits and costs items will be further defined in Table 11 and Table 12 respectively. For the sake of comprehensiveness, all of the benefits that may potentially

come into play for DR program were commented on, regardless of whether they were actually applicable to the proposed program.

The key benefits shown in Table 11 were valued in Chapter 4.

Table 11: Benefit Assumptions

Benefit Items	Definition and Assumptions
Avoided capacity costs	Avoidance of investment in standby solution to ensure that the power system can sustain the highest net load peak for a time horizon of multiple years. The avoided capacity cost is **$89.51 per p.-yr** (See details of calculation in Section 4.1) However, additional capacity is only needed starting in December of 2018 (HQD, 2013, p. 28). Thereby, assuming that DR is deployed in 2016, the benefit accrued for avoided capacity cost for 2016 and 2017 will match that of the market value of capacity in exterior market, $20/kW-year, which is the short-term figure used by HQ Distribution (2015c, p. 5) or **$16.89 per p.-yr** (including planning reserve margin and T&D losses, similar to the calculation in Section 4.1).
Avoided energy costs	DR may help avoiding energy cost by shifting consumption from period with high marginal cost of production to later period with lower marginal cost. The avoided cost of energy, in the proposed program, is rolled in the incremental "Revenues from wholesale DR programs".
Avoided transmission and distribution costs	The avoided cost of transmission infrastructure that will be used in the CBA is $24.60/kW-yr or **$16.52 per p.-yr** with a 0.7-kW-year curtailment and that for distribution infrastructure is **$8.55/kW-yr** and **$5.99 per p.-yr.,** respectively. The assumptions stated above represent 50% of the official avoided cost numbers published by HQ Distribution (HQD, 2015c). HQ Distribution's official numbers were down rated for two reasons. Firstly, HQ Distribution uses the levelized cost of T&D investment as their avoided cost. The use of levelized cost as avoided cost is not compliant with the best practice in North America, which is to use the present worth of investment deferral (annualized) (NAPEE, 2007b, p. 3.11)., The present worth of deferral is typically lower than the levelized cost. Secondly, there is uncertainty surrounding whether DR actually can defer T&D infrastructure investment. The reason for this is that the demand peak of the system and that for any transmission or distribution branch of the network do not necessarily coincide, and thus the avoided cost should account for a coincidence that is less than 1 (Woolf et al., 2013, p. 43).
Avoided ancillary service cost	Ancillary services include frequency regulation, spinning and non-spinning reserve as well and operating reserve margin. It was established, in Section 4.2, that DR has little to no value as an ancillary service in Quebec. The value of avoided ancillary service cost is thereby zero.

Benefit Items	Definition and Assumptions
Revenues from wholesale DR programs	The revenues from wholesale DR program are the incremental revenues accrued as a result of curtailing when wholesale prices are high and buying back when prices are low. In the absence of a competitive market in the Quebec domestic market, price arbitrage was used. In Section 4.1, it was demonstrated that the incremental revenues from price arbitrage between Quebec and NYISO would have been **$9.95 per p.-yr** on average in 2013, 2014 and 2015. The assumption was made that the same incremental revenues would be accrued in the future, pegged to the escalation of electricity price in the U.S. in real $ according to the Department of Energy's Annual Energy Outlook (2015).
Market-price suppression effect	Large-scale DR programs can cause a demand reduction-induced price effect. In other words, an artificial reduction in demand eventually causes market price equilibrium to decrease. The residential DLC program would have a rather small demand impact relative to the total peak demand in Quebec and neighboring market, and thereby it is assumed that market-price suppression effect is nil.
Avoided environ-mental compliance costs	DR program may cause the avoidance of the use of fossil fuel resources during peak periods. These resources would otherwise cause air emissions. For instance, Quebec has a carbon pricing mechanism because it pertains to the Western Climate Initiative and thus electricity generation using natural gas would need to pay for carbon offset. Electricity during peak period in Quebec, however, would have most likely come from hydropower generation, leading to no avoided compliance cost. Electricity in NYISO, however, comes partially from fossil-fuel resources. Fortunately, the State of New York pertains to Regional Greenhouse Gas Initiative, a carbon pricing scheme aimed at the electricity sector. Thereby, avoided carbon-related compliances costs are already included in wholesale prices of power used to calculated the revenues from wholesale DR programs.
Avoided environ-mental externalities	DR program may cause the avoidance of externalities. Externalities are cost incurred by bystanders that are not appreciated in the price of electricity. For instance, in Quebec the most critical externalities would likely come from environmental impacts at HQ Production's newest hydropower project, the La Romaine project. However, I will not attribute any monetary value to avoided externalities from the La Romaine project for two reasons. Firstly, to a certain extent externalities were already appreciated in the overall budget of the La Romaine project, which is the one power generation facility being sold by HQD Production to HQ Distribution as standby capacity in time for December 2018. The budget of the La Romaine project included a significant budget envelope for environmental management and remediation, $300 million (Emond, 2010), and a relatively large payments of $125 million made to local impacted communities as the result of the negotiation and signature of an impact-benefit agreement (Séguin, 2011). These costs are included in the $106.00/kW-year price being charged by HQ Production to HQ Distribution, and are thus already valued through the avoided capacity cost. Secondly, if monetizing externalities is challenging to start with, monetizing externalities that are not already covered by the environmental management budget and by the impact-benefit agreement payments would be even more challenging. This could potentially researched as part of future work.

Benefit Items	Definition and Assumptions
Participant bill savings	Certain DR programs may alter energy consumption pattern at a participant's premise in a way that will lower the participant's energy bills. However, this is not the case for the proposed DR program because residential customers are not charged for capacity, and use a block-structure tariff, not a time-sensitive tariff. Participant bill savings is equal to utility lost revenues, only that bill savings are a benefit to participant and lost revenues are a cost to the non-participants.
Financial incentive to participant	Financial incentive offered to participants in exchange for enrolling in the program and/or staying in the program. The assumption used was provided in Table 12. The financial incentive is a cost to the utility and to the non-participants, but it is a benefit to participants.
Tax credits	Certain jurisdictions may offer tax credits to participants who invest in DR measures. When that is the case, it is considered to be a benefit to the participant and to be a benefit in term of total resource cost. However, that is not the case in Quebec in general, and that is not the case for the proposed program in particular because the utility would incur the entire cost of the DR measure.
Other benefits	Other benefit may include market competitiveness of the utility and/or of the participant, reduce price volatility and improved volatility. Monetizing these benefits will be estimated as part of future work.

Many cost items listed in Table 12 were estimated by HQ Distribution and filed by HQ with the Régie de l'énergie for their projected 100,000-participant program (2015c, p. 31). The attribution of HQ Distribution's published costs to each of the cost item Table 12 was re-constructed based on the clue shared by HQ Distribution in the filing in the form of a budget table (2015c, p. 31), cost-effectiveness test results (2015c, p. 24), as well as comments on the final results (2015c, p. 25).

Table 12: Costs Assumptions

Cost Item	Definition and Assumptions
Program administrator expenses	*Operational* expenditures incurred by the program administrator to run the program such as customer services (e.g. operation of a call centre) and incentive processing. **$10.00 per participant-year (p.-yr)** was used based on the assumption of 50% of the annual operational-expenditure budget (the remainder being used for initial program-deployment administrative work).

Cost Item	Definition and Assumptions
Program administrator capital cost	*Capital* expenditures incurred by the program administrator to implement the program such as early DR deployment efforts, the DR management system, customer relationship management system and early marketing and communications efforts. A cost of **$5,400,000** program administrator capital cost based on the re-construction of the cost structure as per the clues presented by HQ Distribution in its July 2015 filing (2015c), and based on the assumption that 30% of the initial capital investment are fixed (i.e. not dependent on number of participants).
Financial incentive for participant	Financial incentive offered to participants in exchange for enrolling in the program and/or staying in the program. This can take the form of a grant, credit on bill or reduced electricity rate; it can be a one-time payment or routine payments. An on-going financial contribution **$30.00 per p.-yr** was used based on the re-construction of the cost structure as per the clues presented by HQ Distribution in its July 2015 filing (2015c).
DR measure cost, program administrator contribution	Costs incurred by program administrator to install DR equipment in the participants' premises, such as the control switch, shipping and handling, wiring, and installer's fees (including going to and back from the premises). A cost of **$126.00 per participant** upon enrollment was used based on the re-construction of the cost structure as per the clues presented by HQ Distribution in its July 2015 filing (2015c), and based on the assumption that 70% of the initial capital costs are variable (i.e. dependent on the number of participants).
DR measure cost, participant contribution	Costs incurred by participants to install DR equipment in the participants' premises, such as DR-enabled building automated system, for instance. This particular cost item is irrelevant in this particular situation.
Participant transaction cost	Monetized effort spent by participants to enroll in the program such as time spent reading information about the program, filling out application and opening door to installer. **$23.91 per participant** upon enrollment was assumed which is equivalent to one-hour worth of effort monetized at the average hourly wage in Quebec in December 2015 (Statistics Canada, 2016).
Participant value of lost service	The value of lost service is the monetized "annoyance" to the participants due to the participation in the program. Participant will incur minimal disutility from having to change behavior because DLC does not rely on participant changing behaviour (curtailment is triggered by someone else). Furthermore, the risk of lacking hot water will remain low so the participants can maintain their schedule and life habits. Furthermore, DLC does not cause an increment in equipment breakdown or increased equipment wear and tear because it simply relies on turning off the heating elements. For residential DLC, in the absence of any indication, the FERC Framework recommends using 75% of incentive (or **$22.50 per p.-yr**) based on the assumption that the participants would not enroll into the program and stay in the program if the incentive did not compensate for their inconvenience.
Increased energy consumption	Certain DR programs may cause increased energy consumption, like those involving pre-cooling or pre-heating, or those that require turning on embedded back-up fossil-fuel generation during DR events. This is not applicable to the proposed DR program.
Lost revenues to the utility	Certain DR programs may alter energy consumption pattern at a participant's premise in a way that will lower the participant's energy bills, thereby causing the utility to lose revenues. However, this is not applicable to the proposed DR program because residential customers are not charged for capacity, and use a block-structure tariff, not a time-sensitive tariff.

Cost Item	Definition and Assumptions
Environ-mental compliance costs	Certain DR programs may increase the cost for participant to comply with local air emission regulations, like DR program that require turning on embedded back-up fossil-fuel generation during DR events. This is not applicable to the proposed DR program.
Environ-mental externalities	Certain DR programs may increase negative environmental impact by, for instance, shifting energy consumption to off-peak hours when generating resources emit more air pollutants. In Quebec, however, electricity during both on- and off-peak periods is generated with low- to no-emission sources.

Family size may be a factor of influence on people's decision to partake in the program or not. However, family size will not affect the participant's net benefit of participating because people will self-select themselves into the program. They would not decide to participate in the program if, based on their own judgement, the trade-offs outweigh the benefits. For instance, large-family households with superior water usage can decide not to participate because they will assume that the program will be detrimental to them.

All cash flows expected from a DR program, both costs or benefits, ought to be converted into present value (PV) using a discount rate and then cumulated for the entire effective useful life of the DR measure. One typical approach to discounting cash flows is to use the local utility's weighted-average cost of capital (WACC) as the discount factor. The WACC is the overall cost of funding to the utility; it is a blend of the regulated rate of return of the utility and the interest rate of debt financing that the utility expects to have access to in the near term. HQ Distribution uses 5.651% nominal (HQD, 2015c, p. 13) or 3.579% real[19].

The use of the WACC as a discount factor for CBA is controversial because it is said to underestimate the value of resources for future generations because the WACC is higher than the true discount rate of society (Boardman, Moore, & Vining, 2008). However,

[19] Real is the discount rate net of inflation. Inflation was assumed to be 2% per year which is consistent with Canada's monetary policy. ((100+5.651)/(100+2))-100 = 3.579

HQ Distribution's WACC is particularly low, if compared with that of other regulated utilities (Cherniak, Dufresne, Keyte, Mallett, & Schott, 2015, p. 54). This can be explained by the exceptionally-low debt financing that HQ has access due to the fact that it is debt is endorsed by the provincial government and in view of its good financial track record. HQ Distribution's WACC is actually lower than the discount rate recommended by the Treasury Board of Canada for its own policies, 8% real (Treasury Board of Canada Secretariat, 2007, p. 37), and relatively close to the "social time preference rate" of 3% real accepted by the Treasury Board as a "social discount rate" in rare occasions when it is deemed justified to ignore near-term opportunity cost as it is the case for certain environmental regulations (Treasury Board of Canada Secretariat, 2007, p. 38). In summary, because HQ's WACC is relatively low and because this is the official discount rate being accepted by the Régie de l'énergie, HQ's WACC of 3.579% real was used for all of the CBA tests.

The use of the WACC as the discount factor, under a cost-of-service regulation regime, simplifies the computation of the CBA tests because both the annualization of the capital expenditures and the discounting of annuities to calculate the PV are done using the same rate. In addition, the fact that HQ Distribution does not pay corporate income tax because it is a Crown Corporation simplifies the annualization of capital expenditures further because the capital cost allowance (i.e. asset depreciation for corporate income tax purposes) does not need to be taken into account.

The final critical assumption needed to perform the CBA tests is the effective useful lifetime of the DR measure, which in other words means how many years the remote switches will last. The IESO, for instance, uses the expected lifetime of the device itself,

13 years (IESO, 2012). The re-construction of HQ Distribution's own CBA as per the information contained in the July 2015 filing (2015c) suggests that HQ Distribution used an effective useful life of 5 years in its calculation, which may be reflective of participation erosion due non-technical factors, such participants moving out of their house, for instance. I used an effective useful life of 9 years; which is half way between the IESO's assumption that that of HQ Distribution.

The results of the CBA tests were computed using the Moderate potential scenario, i.e. the scenario in which 100,000 participants are to enroll in the program. This assumption, together with all other assumptions that were presented in this section, will form the reference CBA results presented in the next Section.

6.2 Results of Cost-Benefit Analysis

The results of the CBA tests form the business case of the proposed DR program looked at from the angle of most of stakeholders; not only that of the utility but also that of the participants, the ratepayers, the environment and the society. The detailed CBA cash flow table used to calculate the results of the standard tests is in Appendix F.

The results of all of the CBA tests can take any of the following forms: Benefit/Cost ratio (i.e. present value of benefits divided by that of costs), net present value (NPV, i.e. present value of benefits minus that of costs), levelized cost (i.e. PV of all costs divided by cumulative discounted impacts over effective useful life, including T&D losses) or *net* levelized cost (i.e. NPV divided by cumulative discounted impact over effective useful life, including T&D losses)[20]. A DR program is deemed to "pass" any of the standard CBA test

[20] Levelized cost are not relevant to all of the tests (i.e. all of the perspectives).

when the benefits outweigh the costs for that specific test, thus when the Benefit/Cost ratio is above 1, or when the NPV is positive.

Table 13 presents the *reference* results for the five standard tests when accounting for all of the assumptions presented in the previous section, Section 6.1. These results are for the moderate-potential scenario, i.e. with the enrollment of 100,000 participants.

Table 13: Cost-Benefit Analysis Results (Reference Results)

Participant Cost Test (PCT):						
Benefits (m$):	$23.6	B/C Ratio:	1.17			
Cost (m$):	$20.1	NPV (m$):	$3.5			
Program Administrator Cost Test (PAC):						
Benefits (m$):	$81.8	B/C Ratio:	1.66	Levelized Cost:	$82.79	($/kW-yr)
Cost (m$):	$49.4	NPV (m$):	$32.4	Net Lev. Cost	-$54.34	($/kW-yr)
Rate-Impact Measure Cost Test (RIM):						
Benefits (m$):	$81.8	B/C Ratio:	1.66			
Cost (m$):	$49.4	NPV (m$):	$32.4			
Total Resource Cost Test (TRC):						
Benefits (m$):	$81.8	B/C Ratio:	1.78	Levelized Cost:	$76.93	($/kW-yr)
Cost (m$):	$45.9	NPV (m$):	$35.9	Net Lev. Cost	-$60.20	($/kW-yr)
Societal Cost Test (SCT):						
Benefits (m$):	$73.7	B/C Ratio:	1.60			
Cost (m$):	$45.9	NPV (m$):	$27.8			

Because all of the B/C ratios are above "1", the results of the CBA suggests that it is worthwhile engaging in residential DLC of hot water heaters from the perspective of all stakeholders. The PCT suggests that the participants would accrue a net benefit, the PAC suggests that the cost of the proposed program ($82.79/kW-yr) is less expensive to HQ Distribution to procure than business-as-usual resources (saving of $54.34/kW-yr), the RIM suggests that average Quebec rate-payers would benefit through future rate increases being dampened, the TRC suggests that the proposed program would lower the overall use of resources to obtain the same electrical services, and the SCT suggest that Quebec society

as a whole would be better off if the proposed program was pursued. The SCT is lower than the TRC because the SCT does not account for revenues from wholesale DR programs as a benefit.

The PAC and the RIM results are identical because the lost revenues, the main distinction between the two tests, are nil for the proposed program. The TRC results are above that of the PAC and the RIM because in a residential DR program the control devices and installation are paid for by the utility, and then the utility often has to add an incentive (in this case, a *recurring* annual incentive was used) to drive participation. The TRC does not account for financial incentive, because financial incentives are seen simply as a "transfer payment", i.e. a cash flow which does not represent of a cost of tangible resource.

It is unclear whether the program would be regressive or progressive. On the first hand, as demonstrated by the positive RIM test, the program will lower electricity rates for all consumers. Low-income electricity customers being more impacted than other customers by electricity rate, they will benefit more from the program than other customers. From this perspective, the program is progressive. On the second hand, low-income customers are less likely to partake in the program itself because they are more likely to rent their homes rather than owning them, because they have smaller water tanks, and/or because they often have larger families with larger water uses and thus will not sign up in the program. This is a regressive aspect of the program. Assuming that the program was "regressive", I propose the following pragmatic approach to mitigate regressiveness: integrate the delivery of electric water heater DLC with existing DSM low-income programs. For instance, the utility would install the control equipment along with other DSM measures, and then could adjust the annual performance incentive upward for low-

income households. Using existing low-income program as a vehicle for the DLC program will lower the transaction cost associated with verifying whether a household has, in fact, a low income.

The SCT, which represents the perspective of the society, is actually lower than the TRC because the revenues from wholesale DR program, $9.95 per p.-yr, are not a benefit that are accrued by the society as a whole, they are to be accrued by actors in the power markets, in this case HQ Distribution and HQ Production. Revenues from wholesale DR program nevertheless represent an additional driver for market actors to adopt the DR program that comes at no cost to the society.

I performed a CBA performed in support of my thesis using cost assumptions made by HQ Distribution and using the same participation rate. The same standard tests, the TRC, PCT and RIM, were used. Results, however, were not the same as illustrated in Table 14.

Table 14: Comparison between Thesis CBA Results and HQ Distribution's CBA Results

NPV in m$:

	TRC	PCT	RIM
Thesis reference results w/ moderate potential:	$36	$3	$32
HQ Distribution's results:	$9	$14	($5)

The RIM results as calculated by HQ Distribution suggest that average ratepayers would have to cross-subsidize the participants in the DR program because the NPV is negative. My thesis actually suggests otherwise. (A negative RIM in Quebec does not preclude the program to be rolled out because the TRC is the main driver of decision.)

The discrepancies observed in Table 14 between HQ Distribution's CBA calculations and my CBA calculations can be explained by the following differences in the assumptions and approach to DR valuation:

- HQ Distribution used an **effective useful life** of "5" years instead of "9", which has a downward impact on the TRC and the RIM as compared with my CBA results. This is the one assumption with the largest impact on the TRC and RIM results.
- HQ Distribution did not incorporate **Participant transaction costs** and **Participant value of lost service**, which had an upward impact on the TRC and the RIM as compared with my CBA. This is the main factor explaining the steep discrepancy between the PCT result according to HQ Distribution and the PCT result that I calculated.
- HQ Distribution used an avoided cost of capacity of $106.00/kW-year starting in 2016 and onward, which has an upward impact on the TRC and RIM. I used $20.00/kW-year in 2016 and 2017, and started using $106.00/kW only in 2018 and onward, when the provincial power system is expected to face a deficit.
- HQ Distribution did not incorporate **T&D losses** and **planning reserve margin** in the avoided cost of capacity, which has a downward impact on the TRC and the RIM.
- HQ Distribution did not incorporate **avoided cost of T&D infrastructure,** and incremental **revenues from wholesale DR program** (i.e. economic dispatch of DR), which had a downward impact on the TRC and the RIM.

The next section, sensitivity analysis, will explore the magnitude of the upward and downward discrepancies caused by the changes in assumptions.

6.3 Sensitivity Analysis

Section 6.3 consists of varying the inputs into the CBA in order to gain an appreciation of the tolerance of the CBA results to errors in the assumptions. The purpose is to learn what assumptions and what parameters are worth paying more attention to and spending more resources on to refine them and keep them under control in an eventual deployment of the program. The results of the sensitivity analysis presented in the next pages focus on the most critical assumptions; which are those with both the highest degree of uncertainty and highest degree of impact on the results.

Table 15 shows the degree of sensitivity to the three most critical parameters: effective useful life, participation and initial capital cost. The length of effective useful life that was tested spans from 5 years (i.e. HQ Distribution's assumption) and 13 years (i.e. the IESO's assumption based on the equipment lifetime). The level of Participation was tested from the lower-achievable level, 68,490 participants, to the upper-achievable level, 171,354 participants. Both the effective useful life and the level of participation were tested against levels of initial capital cost carrying from 70% of the reference initial cost (30% below) and 150% of the reference cost (50% above). The result shown in "bold" in the tables is the result of reference. The TRC was used because this is the one primary driver of decision for DSM programs in Quebec.

Table 15: Sensitivity to Critical Drivers

NPV under the Total Resource Cost (TRC) test in m$.

(a)

		Effective useful lifetime				
		5 yr	7 yr	**9 yr**	11 yr	13 yr
Initial capital cost (% of reference)	-30%	$12.6	$27.4	$41.3	$54.3	$66.5
	-15%	$9.9	$24.7	$38.6	$51.6	$63.8
	0%	$7.2	$22.0	**$35.9**	$48.9	$61.1
	15%	$4.5	$19.3	$33.2	$46.2	$58.4
	30%	$1.8	$16.6	$30.5	$43.5	$55.7
	50%	($1.8)	$13.0	$26.9	$39.9	$52.1

(b)

		Participation (# of households enrolling)				
		68,490	84,245	**100,000**	135,677	171,354
Initial capital cost (% of reference)	-30%	$24.3	$32.8	$41.3	$60.6	$79.8
	-15%	$21.6	$30.1	$38.6	$57.9	$77.1
	0%	$18.9	$27.4	**$35.9**	$55.2	$74.4
	15%	$16.2	$24.7	$33.2	$52.5	$71.7
	30%	$13.5	$22.0	$30.5	$49.8	$69.0
	50%	$9.9	$18.4	$26.9	$46.2	$65.4

The results in Table 15(a) suggest that the one factor that has the potential to upset the business case of residential DR interesting is the effective useful life. If HQ Distribution's effective useful life assumption were correct, then the margin by which benefit outweigh cost becomes thin, or even negative. It is worth investing more to purchase better equipment (e.g. two-way communicating switch, or switches with a tank temperature reading to prevent lack of hot water) to ensure that participants will stay in the program for as long as possible.

As seen in Table 15(b), a low participation rates does not push the TRC result downward to the same extent than a poor effective useful life does. However, a high participation rate has the potential to improve the cost-efficiency of the program by a large

degree. The table suggests it is worthwhile investing more in marketing and communication, initially, to capture more participants. For instance, if a 50% increase in total budget was needed to push the participation rate to the upper-achievable level, then it would be worthwhile incurring that cost because the TRC result would increase.

Integration and valuation of economic dispatch of DR is a key innovation proposed by my thesis. Table 16 presents the results of a sensitivity analysis around the valuation of economic dispatch of DR. Table 16(c), (d) and (e) test the effect of changing the revenues from wholesale program against changing the avoided cost of T&D infrastructure, the level of emergency curtailment and the initial cost, respectively. The revenues from wholesale DR program vary from $0.00 per participant-year (i.e. absence of economic dispatch) to $14.24 (i.e. triggering 100% of the DR routineswhich represents up to 648 events per year).

Table 16: Sensitivity to Incremental Revenues from Economic Dispatch of DR

NPV under the Total Resource Cost (TRC) test in m$.

(c)

		T&D Avoided Cost (% of HQ's official figures)				
		0%	25%	**50%**	65%	80%
Revenues	$0.00	$10.1	$18.9	$27.8	$33.1	$38.4
from	$4.98	$14.2	$23.0	$31.8	$37.1	$42.4
wholesale	**$9.95**	$18.3	$27.1	**$35.9**	$41.2	$46.5
DR prgms	$12.10	$20.0	$28.8	$37.7	$43.0	$48.3
per p.-yr	$14.24	$21.8	$30.6	$39.4	$44.7	$50.0

(d)

		Emergency Curtailment in kW-yr per participant					
		0.30	0.50	0.60	**0.70**	0.80	0.90
Revenues	$0.00	($14.3)	$6.7	$17.2	$27.8	$38.3	$48.8
from	$4.98	($10.3)	$10.8	$21.3	$31.8	$42.4	$52.9
wholesale	**$9.95**	($6.2)	$14.9	$25.4	**$35.9**	$46.4	$57.0
DR prgms	$12.10	($4.4)	$16.6	$27.2	$37.7	$48.2	$58.7
per p.-yr	$14.24	($2.7)	$18.4	$28.9	$39.4	$50.0	$60.5

(e)

		Initial Cost (% of reference)					
		-10%	**0%**	15%	25%	40%	50%
Revenues	$0.00	$29.6	$27.8	$25.1	$23.3	$20.6	$18.8
from	$4.98	$33.6	$31.8	$29.1	$27.3	$24.6	$22.8
wholesale	**$9.95**	$37.7	**$35.9**	$33.2	$31.4	$28.7	$26.9
DR prgms	$12.10	$39.5	$37.7	$35.0	$33.2	$30.5	$28.7
per p.-yr	$14.24	$41.2	$39.4	$36.7	$34.9	$32.2	$30.4

Table 16(c) shows that the magnitude of the variation due to the level of avoided cost of T&D infrastructure is wider than that for the value of economic dispatch, which is an indication that the avoided cost assumption related with T&D infrastructure is a key assumption. In the future, more research should be undertaken to improve the valuation model for T&D avoided cost. However, even if the value of avoided T&D infrastructure upgrade was nil, the proposed program would still pass the TRC test. Similarly, Table 16(d) illustrates the fact that the value of DR would come from the value of emergency curtailment more than the value of economic dispatch.

Table 16(e) points to the fact that the TRC increment between the absence of economic dispatch ($0.00 per p.-yr) and the triggering of 20% of the DR routines with a positive net revenue ($9.95 per p.-yr) is worth $8.1 million (present value) for 100,000 participants over the course of the 9-year effective useful life of the DR measures. Table 16(e) also suggests that it would be worthwhile investing an additional 40% of initial capital cost, if needed, to pursue economic dispatch if performed as forecasted in Section 4.2. However, since the yield of economic dispatch is uncertain, it would probably be wise to impose a ceiling on additional investment to no more than 25% (by assuming that the yield will be 50% of what was forecasted or $4.48), which represents $4.5 million.

The purpose of Table 17, below, is to study the effect of the level of financial incentive and the participant value of lost services. The table shows the influence of these two parameters on the results of the TRC, PCT and RIM.

Table 17: Sensitivity to Participant Incentive and Value of Lost Services

NPV under the Total Resource Cost (TRC) test in m$.

(f)

		Financial incentive in $ per participant-year				
		$0	$15	**$30**	$45	$60
Participant value of lost service per p.-yr	$0.00	$53.6	$53.6	$53.6	$53.6	$53.6
	$11.25	$44.8	$44.8	$44.8	$44.8	$44.8
	$22.50	$35.9	$35.9	**$35.9**	$35.9	$35.9
	$26.25	$33.0	$33.0	$33.0	$33.0	$33.0
	$30.00	$30.0	$30.0	$30.0	$30.0	$30.0

NPV under the Participant Cost Test (PCT) in m$.

(g)

		Financial incentive in $ per participant-year				
		$0	$15	**$30**	$45	$60
Participant value of lost service per p.-yr	$0.00	($2.4)	$9.4	$21.2	$32.9	$44.7
	$11.25	($11.2)	$0.6	$12.3	$24.1	$35.9
	$22.50	($20.1)	($8.3)	**$3.5**	$15.3	$27.1
	$26.25	($23.0)	($11.2)	$0.6	$12.3	$24.1
	$30.00	($25.9)	($14.2)	($2.4)	$9.4	$21.2

NPV under the Rate-Impact Measure test (RIM) in m$.

(h)

		Financial incentive in $ per participant-year				
		$0	$15	**$30**	$45	$60
Participant value of lost service per p.-yr	$0.00	$56.0	$44.2	$32.4	$20.6	$8.9
	$11.25	$56.0	$44.2	$32.4	$20.6	$8.9
	$22.50	$56.0	$44.2	**$32.4**	$20.6	$8.9
	$26.25	$56.0	$44.2	$32.4	$20.6	$8.9
	$30.00	$56.0	$44.2	$32.4	$20.6	$8.9

Table 17(f) shows that the assumed participant value of lost service decreases the result of the TRC significantly. If this cost had been ignored ($0.00 per p.-yr) the TRC would have been $17.7m higher. Table 17(f) is also a reminder that the TRC, by definition, is blind to the level incentive. Table 17(g) illustrates the interaction between the level of incentive and the value of lost services for the participant. Participating in the DR program can only be worthwhile if the incentive makes up for the value of lost service, otherwise the PCT is negative and thereby the program would be detrimental to the households who participate. This is unlikely to happen, however, since only the households who consider the incentive to be higher than the value of lost service will self-select themselves and enroll into the program.

Table 17(h) shows that the level of incentive has a considerable impact on the RIM results. Table 17(h) is illustrative of the split of the total net benefit ($56.0m) between the participants and the ratepayers. For instance, at $30 per p.-yr, the split is $32.4m for the ratepayers and thus the remaining $17.6m is for the participants. To finish with, Table 17(h) reflects the fact that the participant value of lost service is not factored in the RIM.

The sensitivity analysis has proven the robustness of the results. The level of benefit is sufficient to outweigh the cost despite most variation in the inputs introduced during the sensitivity analysis, and there are enough sources of benefits to provide confidence that one single faulty assumption will not put the entire business case at risk. In this, economic dispatch of DR helps by adding one additional source of benefit.

Chapter 7. Conclusion

My thesis established the value DLC of electric water heaters in Quebec in the residential sector using a multi-disciplinary approach combining engineering, economics, policy analysis and business.

Quebec has a number of particularities compared with most other jurisdictions in North-America due to its monopolistic electricity market and the high penetration of cheap hydropower. Based on a high-level review of the technology and of the market structure, I proposed an approach to value the benefit of DR in Quebec through emergency triggering of DR to achieve steep load curtailment during critical peaks in the winter, as well as economic dispatch of DR. The former was a relatively conventional form of valuation. The latter was a novel approach that had not been tried in Quebec, and that needed adaptation to the particularities of the market structure.

I discussed how increasing the amount of DR in Quebec is a key enabling factor to increase the penetration of variable renewable energy resources, such as wind power and solar photovoltaic, not only in Quebec but also in nearby markets like that of New York, New England, Ontario, and the Maritimes. Economic dispatch of DR can help HQ to increase its revenues through price arbitrage, which is good for all of Quebec citizens who benefit from the accrual dividends from HQ's in the provincial government's budget. It is also excellent for Quebec's neighbors who are in need for flexible resources, even more than Quebec is, to cope with the growing penetration of variable renewable resources. To a large extend Quebec can already provide flexibility to its neighbors through the use of its large northern hydro reservoirs which can store large amount of energy and release it almost at will. Through the use of DR, Quebec could gain a greater ability to manage its

own domestic demand, and thus could bolster the flexibility it can offer to its power trade partners.

DLC of electric water heaters is a viable solution for Quebec so much that HQ Distribution officially announced the incoming deployment of DLC of electric water heaters, the same program concept, across the province. HQ Distribution even filed its own valuation results and cost-benefit analysis. My thesis thereby constitutes a constructive criticism of the valuation and the economic analysis performed by the utility. The approach to analysis was built on industry best practices and sought to be as comprehensive as possible. The hope is that my thesis will support the utility in its intention to deploy more DR in Quebec, and at the same time unveil potential improvements to the program.

A province-wide deployment of DLC of electric water heaters has the potential to provide between 52 and 130 MW of emergency peak demand curtailment to HQ Distribution, with an associated avoided planning reserve margin of 5.8 MW or 14.4 MW, respectively. The two sets of number provided are the lower- and the upper-achievable potential and they include T&D losses. Emergency curtailment represents 0.7 kW per household and should be valued at $89.51 per year per participating household when accounting for avoided T&D losses and avoided planning reserve margin. It was also demonstrated that the CLPU does not cause any problem neither after emergency curtailment nor as part of economic dispatch.

It was found that economic dispatch would have be worth $9.95 per year per participating household on average if DLC of electric water heaters had been used for arbitrage between Quebec and NYISO in 2013, 2014 and 2015. The figure was assumed to be a fair estimate of the worth of economic dispatch going forward and was pegged to

the escalation of the price of electricity according to the DOE's 2015 Annual Energy Outlook. While the value that was found is lower than that of emergency curtailment, it is an incremental revenue worthwhile pursuing regardless, it may contribute to mitigating the risk of having all of the benefit of a certain DSM technology coming from a single source, and it has the potential to help with the adoption of variable new renewables.

Four caveats of the valuation economic dispatch are as follows. Firstly, the approach developed assumes that the transmission infrastructure between Quebec and the main load centers in New York will be able to carry the extra power being freed up in Quebec's domestic market. Secondly, the valuation is based on the assumption that the day-ahead market wholesale prices observed in 2013-2014-2015 in NYISO are representative of wholesale prices of NYISO going forward, which may not be the case. Thirdly, the approach assumes that HQ's traders have perfect knowledge, in advance of scheduling DR, of what the DAM price for the incoming day is. In reality, they will be using forecast. Fourthly, the approach assumes that DR in Quebec, which is a new competing resource in the NYISO market, will not have impact on DAM prices. A more thorough analysis would be needed in the future to improve the quality of the forecast.

The proposed program passes the TRC test, which is the main driver of decision about DSM in Quebec, with a NPV of $35.9 million, assuming a "moderate participation" scenario (i.e. 100,000 participants, which is between the numbers of participant for the lower- and upper-achievable potential scenarios). The proposed program passed all of the other standard economic tests, which suggests that the program would be to the benefit of all stakeholders. The economic analysis was subjected to a sensitivity analysis which demonstrated the robustness of the results.

A number of inconsistencies were uncovered between the economic analysis results published by HQ Distribution and my results. Potential explanations were provided with the purpose of suggesting improvements to HQ Distribution's economic analysis of DR.

Going forward, additional work on DR valuation could involve:

- Working on the determination of the local value of DR on distribution and transmission infrastructure in areas of high constraints in the distribution and transmission system. It was found that T&D avoided cost has the potential to be a considerable benefit of DR, however the official avoided cost numbers available were mostly valid for energy conservation programs, not so much for DR. They were de-rated before being used in the economic analysis.
- Improving the economic-dispatch cycling optimization algorithm through the use of a bottom-up modeling approach and improved linear-programming approach, in particular to improve the ability to model the CLPU and assess the likeliness of lacking of hot water at a higher degree of resolution. The use of a bottom-up modeling approach would provide more insight about the increase of probability of lack of hot water.
- Developing optimal and self-correcting DR dispatch decision rules using option value theory based on a maximum number of DR events allowed for each year per participant in the program.

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Appendix A. DLC Ware

Appendix A provides a representative list of technologies to give a perspective of what the state of the art is for residential DLC of EWH.

Communication Solutions

Utilities and system operators send control signals through one or many methods, listed below, to the control hardware located in the premise of residential customers.

In the early days of DR, the communication signal went only one way: from the utilities to the control hardware located in their customers' premises. Nowadays, utilities newly adopting DLC or utilities in the process of updating their DLC program are adopting two-way communication solutions, where the control hardware not only receive the control commands but also can reply to the system operator. The information being sent to the system operator usually includes the status of the control (i.e. ON or OFF), but may also include water temperature readings.

The primary benefit of two-way communication over one-way communication mostly lies in the ability to evaluate load impact of DLC with a higher degree of accuracy. Two-way communication gives the operators the ability to interrogate the controllers to verify whether they received and executed the commands that they were given; it also allows the operators to verify that they still exist and whether they are operational. With one-way communication, operators had no guarantee that the controllers were properly installed and receiving. Over time, many households would disconnect the controllers (either accidentally or on purpose). Communication glitches would also occur. Provided that it was impossible to verify the percentage of EWH that were actually being switched OFF, system operators and regulators would down rate the load curtailment obtained from DLC, sometimes in an overly-conservative manner.

In order to send a command from the system operator to the controllers, and retrieve data from the controllers, the signals need to cross two main lengths: firstly from the centralized console of the DR management system (or DRMS) to the household gateways, and secondly from the gateways to one or many controllers inside each households.

Communication technologies from the DRMS to the household gateways:

Table A-I: Communication Technologies

Communication Technologies	Description
From the DRMS to the household gateways	
Radio frequency (RF)	RF have been used since the 1970s, as mentioned in by Hastings (1980) to convoy commands over the air from the utility's own network of emitters to controllers' receiver. Nowadays, utilities would not set up their own network of antenna, but instead would use paging system through the existing cellular communication infrastructure, or else would use satellite communication for far-away remote areas – like communities located in Nunavik or on the Lower North Shore, in Northern Quebec, for example.
Power-line communication	Power line communication (also known as power-line carrier) uses the utility's own electrical wires to send and retrieve signals by emitting low voltage differential at frequency higher than that of the alternative current flowing through. The signals can be deciphered by receivers plugged on the power lines. It is still being used by certain utilities for DLC, such as the Delaware County Electric Cooperative in New York State (Cody, 2014).
Broadband connection	Coaxial cable (as in cable TV company connection), optical fiber, or twisted pair (as in digital subscriber line from a phone company connection) capable of wide bandwidth data transmission. Signals flow both ways through Transmission Control Protocol/Internet Protocol (TCP/IP).
Household gateways through a LAN and in the controller(s)	
Wired connection	A LAN can be established using Category-5 cables (also known as Ethernet cables) thorough the household or any other form of low-voltage or control cables. Power-line communication solutions can also be used inside buildings.
Wireless connection	Three dominating trademarked technologies became commonplace in North-America for LAN communication through RF: Wi-Fi, Bluetooth, and ZigBee.

They all have their strengths and weaknesses, and none of them imposed itself as the one only solution for EWH controllers. Wi-Fi is designed for high-bandwidth communication with personal computers located relatively anywhere in a household and became almost as

ubiquitous as broadband internet is – hence many control devices discussed below are using it. Wi-Fi does, however, require more power than the two other solutions which makes it impossible to power with batteries, for instance. Bluetooth was designed to be a medium-bandwidth short-range (virtually just one room) low energy-consumption solution. ZigBee was designed to be a low-bandwidth low energy-consumption solution. Despite being low-bandwidth, ZigBee's communication capabilities suffice for most energy management applications, including interfacing with EWH controllers. ZigBee is an open standard rather than a proprietary technology, like WiFi and Bluetooth were, and was designed to be cheaper and simpler.

Table A-II: Families of Communication Infrastructures

Families of Communication Infrastructures	Description
Supervisory control and data acquisition (SCADA)	A SCADA is a family of control ware that uses coded signals over radio frequency and/or direct wiring to send control commands and retrieve information from a large territory, such as that covered by power transmission and distribution infrastructure. SCADA system has both distributed and centralized control capabilities. Most North American power utilities, including Hydro-Quebec, have traditionally used SCADA systems to monitor power outages, voltage, frequency and power flows in generating stations, power lines, transformer stations and feeders across their service territories. SCADA communication networks, however, typically do not extend to residential customers' meters. The main SCADA system vendors include Siemens, Honeywell, ABB, Schneider Electric, Rockwell Automation, and Emerson.
Advanced metering infrastructure (AMI)	AMI invokes the new generation of meters, the smart meters, that come with two-way communication capabilities and near real-time metering. Smart meters also have low-voltage control wiring port and radio frequency emitters and receivers. They can either connect to a wireless local area network (LAN) or serve as the gateway to a wireless LAN. The utilities typically communicate with all smart meters within a neighborhood through RF routers, and then use the telecommunication infrastructure of a large traditional telecom company to flow the data back and forth from a central location to the routers. Smart meters located in rural or remote area might be accessed through the cellular infrastructure or event through satellite communication. Smart meters and all the ware used to communicate with them are usually interfaced with the legacy SCADA system, providing the Utility with powerful tools to manage its assets and its business.

Families of Communication Infrastructures	Description
Internet or cloud computing	Increasingly, a number of vendors have created commercial internet-based platforms that interface with the customers' buildings through their broadband connection, using the building automation system for non-residential customers or using the model and router for residential customers as gateways. DR events could thereby be triggered simply through a broadband internet connection, without a utility or system operator developing its own communication solution.

Vendors of new-generation space heating/cooling thermostats, also known as programmable communicating thermostats, propose to the utilities to interface with their control platform. This particular approach to residential DR program is called "bring-your-own-thermostat". A number of high-profile vendors, such as Nest Laboratory, Honeywell (which makes the Lyric, among many others), Alarm.com, Radio Thermostat, and EnergyHub sell attractive advanced programmable communicating thermostats which give the ability for home occupants to interface with the thermostats through an internet platform. Each of these internet platforms typically enables a number of features such as remotely controlling the programmable communicating thermostat as well as the integration of in-home energy display, easy set point scheduling, and a wide selection of analytical tools. Upon enrolment by the home owners, the vendors can provide utilities with the ability to trigger DR events through an application programming interface (API) built in each of the proprietary internet platforms. Many vendors have agreed to build their API based on one single standard, the OpenADR standard (OpenADR for Open Automated Demand Response). In other words, utilities can thereby trigger DR events using programmable communicating thermostats made by multiple vendors from one centralized piece of software via the Internet.

This particular communication channel has primarily been used for programmable communicating thermostats ; but one could envision the internet to be a viable communication

route for EWH controllers in the near future just as it was for programmable communicating thermostats. The main drawback, however, is that it requires the households to have both broadband internet and a wireless router. Even if these became commonplace, nowadays, it does render some of the utilities' customers ineligible, in particular among low-income customers and customers located in rural or remote areas, which would make such an approach particularly challenging for a government-owned utility such as Hydro-Quebec.

Controllers

To date, the majority of commercial and pre-commercial devices fit to control EWH are control switches. The control solutions that were found during the research are listed below:

Table A-III: Commercialy-Available Control Devices for EWH

Controllers	Description
Cooper Power Systems' Advanced Intelligent Load Control Switch	Cooper Industries (owned by EATON) is a multinational electrical equipment manufacturer. Cooper's most advanced control switch is multiple-relay control switches with a ZigBee emitter/receiver (also fit for two other RF communication protocols and power line communication) that can be installed near the EWH or near the electrical panel box. It uses the utility smart meter as its gateway. It has 180-day worth of data logging capability for measurement and verification purposes. Its chipset carries a cycling and learning algorithm and a price-based control fit for air conditioning (though they were not designed for EWH). All of Cooper's control switches communicate with its proprietary DRMS, the Yukon system (Cooper Power Systems, 2013). Cooper is the dominating manufacturer of DR ware in Ontario, a neighboring province[21].
Energate' Wired Load Switch	Energate is a start-up company located in Ottawa, Ontario, specialising in residential DLC and home energy management. Energate's switch carries one relay and can communicate alternatively through a low-voltage control wire, and a ZigBee emitter/receiver. Energate has its own DRMS to control the switches. Energate's product can either use the utility smart meter as the gateway or Energate can also supply its own gateway. The benefit of adding an Energate gateway is to allow for broadband connection of the control switch. In addition to the control switch and to the gateway, Energate's kit can come with a programmable communicating thermostat, an in-home energy display, wall power outlet switches for other plug-in loads, and an internet-based customer energy management portal. It can thereby be expanded incrementally to add more home energy management features (Energate, 2015). It is the second most important vendor of DR ware in Ontario after Cooper[22].

[21] Personal communication with a sales representative from Cooper.
[22] Personal communication with a sales representative from Energate.

Controllers	Description
Emerson's Water Heater Switch	Emerson Electric Company is a multinational manufacturer and service providers. Emerson's switch was specially designed for EWH. Their switches can latch on directly on the junction box, and the casing can be screwed directly on the tank (although the junction box of American water heaters is located on top of the tank instead of near the upper door as in Quebec). The manufacturer promises faster and cheaper installation. In addition, Emerson's switch carries a temperature sensor that can be fitted on the hull of the tank and can help with DLC optimization. It also carries a current sensor that provides information on the load being shed for measurement and verification purpose. Its chipset carries a learning algorithm to optimize the load shifting. It carries a Universal Smart Network Access Port (USNAP) where the installer can connect any communication emitter/receiver needed (Emerson, 2015). The USNAP is a new ANSI standard, the CEA-2045 Standard, created to make energy management devices increasingly vendor-neutral and adaptable (USNAP Alliance, 2015).
Comverge's IntelliPEAK DirectLink	Comverge is a company specializing in delivering comprehensive turn-key DSM program including both energy efficiency and DR. Comverge's switch can communicate through Wi-Fi and cellular paging. It contains two programmable relays. In addition to execute remotely triggered command, it also allows the home owner to program shut down schedule based on time-of-use prices (Comverge, 2015).
Sunnovations' Aquanta	Aquanta is a new venture that promises to do to EWH what the Nest did to programmable thermostats. Sunnovations is a vendor of solar water heater monitoring and control systems. The manufacturer is advertising a load control switch that home owners can install themselves, which connects to broadband internet through the Wi-Fi network, that can be interfaced with through an internet platform, and then can optimize the operation of EWH through features and algorithms that both reduce the operation cost and avoid lacking hot water. Official release of the Aquanta solution is planned for January 2016. Few details have been made public so far (Sunnovations, 2015).
Steffes' Grid-Interactive Electric Thermal Storage	Steffes is a research and development company as well as equipment manufacturer that developed a long line of electrical thermal storage products for space heating and domestic water heating in all sectors (residential, commercial/institutional and industrial). Lately, they have been piloting a new trademarked solution, Grid-Interactive Electric Thermal Storage (GETS), in Hawaii. Hawaii has the highest rooftop solar PV penetration in the United States and, because it is an archipelago, it is facing a steep challenge to absorb all that intermittent electricity. GETS entails a DRMS, a specially-designed EWH, control devices and a centralized control optimization algorithm. Steffes' GETS solution can use a pool of EWH to deliver not only load shifting but also fast ramping and regulation services to utilities and system operators, just like utility-grade electric battery storage solutions can (Steffes Corporation, 2015).

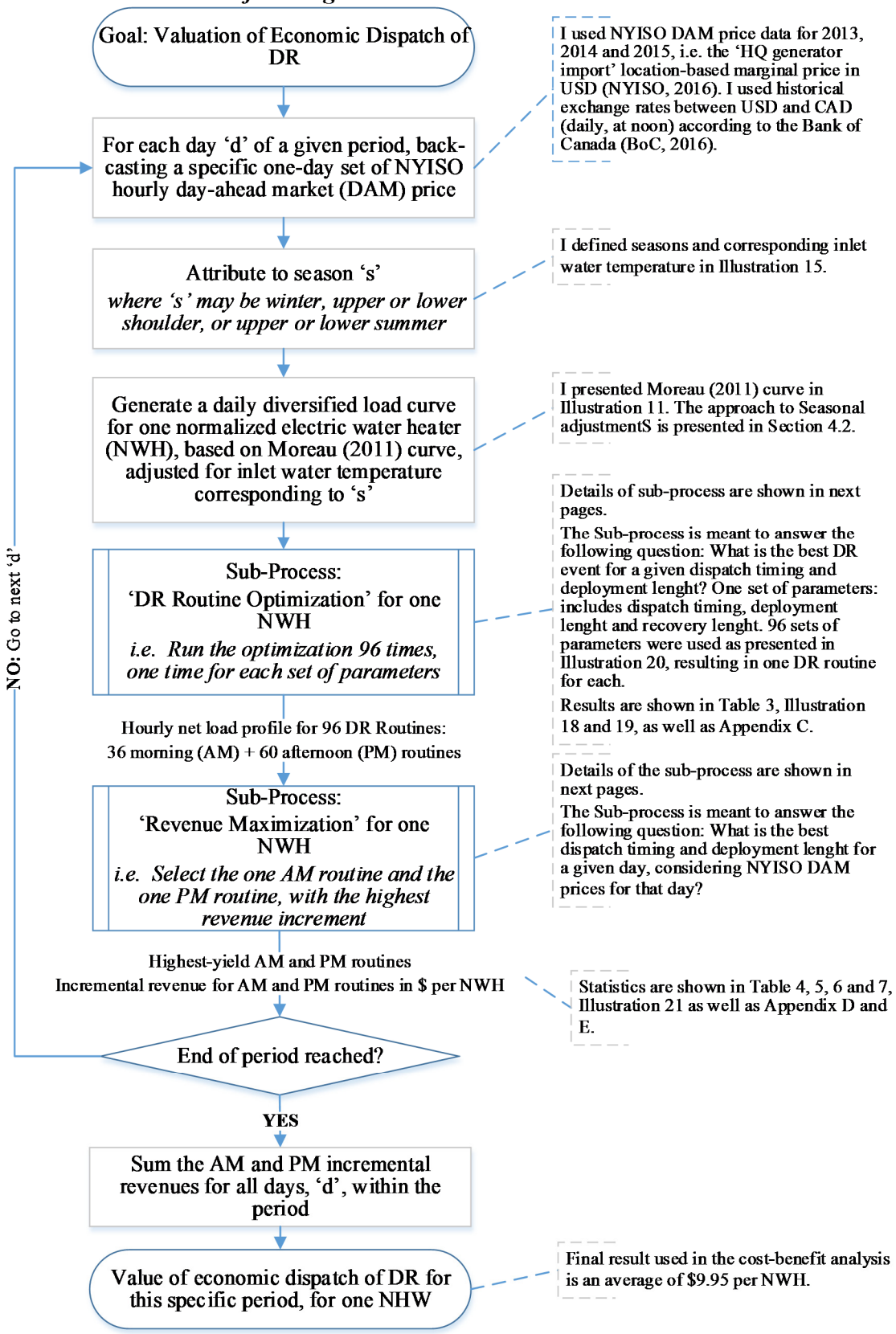
All of the solutions listed above shared the following two characteristics: they all have two-way communication capability and their firmware (i.e. the piece of software carried within the chipset) can be reprogrammed and updated remotely.

Appendix B. Economic Dispatch Valuation Algorithm

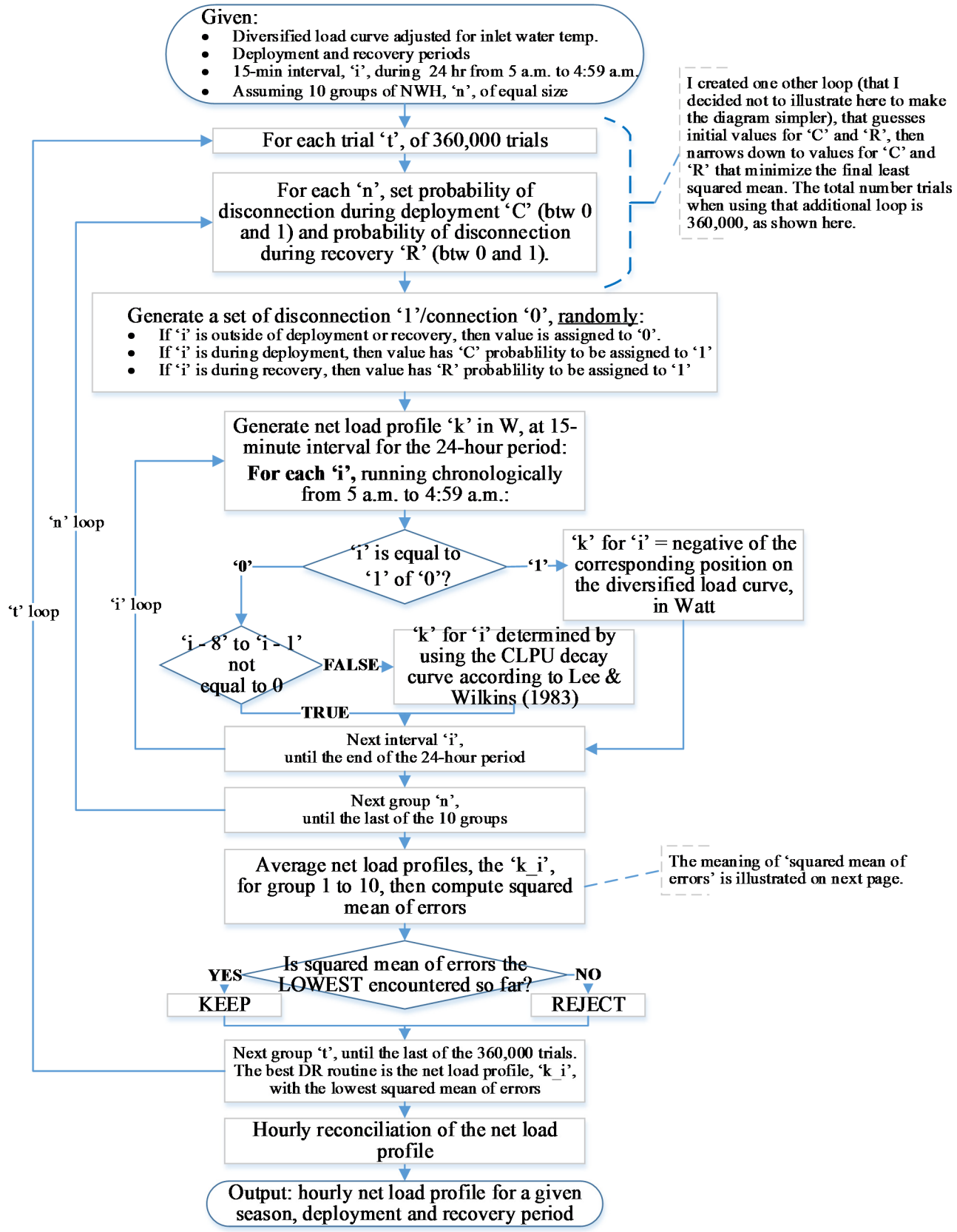
Content:

- Schedule 1: Overview of the Algorithm
- Schedule 2: DR Routine Optimization
- Schedule 3: Illustration of the Least Squared Mean Approach
- Schedule 4: Revenue Maximization

Schedule 1: Overview of the Algorithm



Schedule 2: DR Routine Optimization



Schedule 3: Illustration of the Least Squared Mean Approach

The retained routine was the one DR routine with the "highest" curtailment, then "lowest" and "most constant" recovery. Whether a routine is better than another was determined through least mean squared error method, illustrated below.

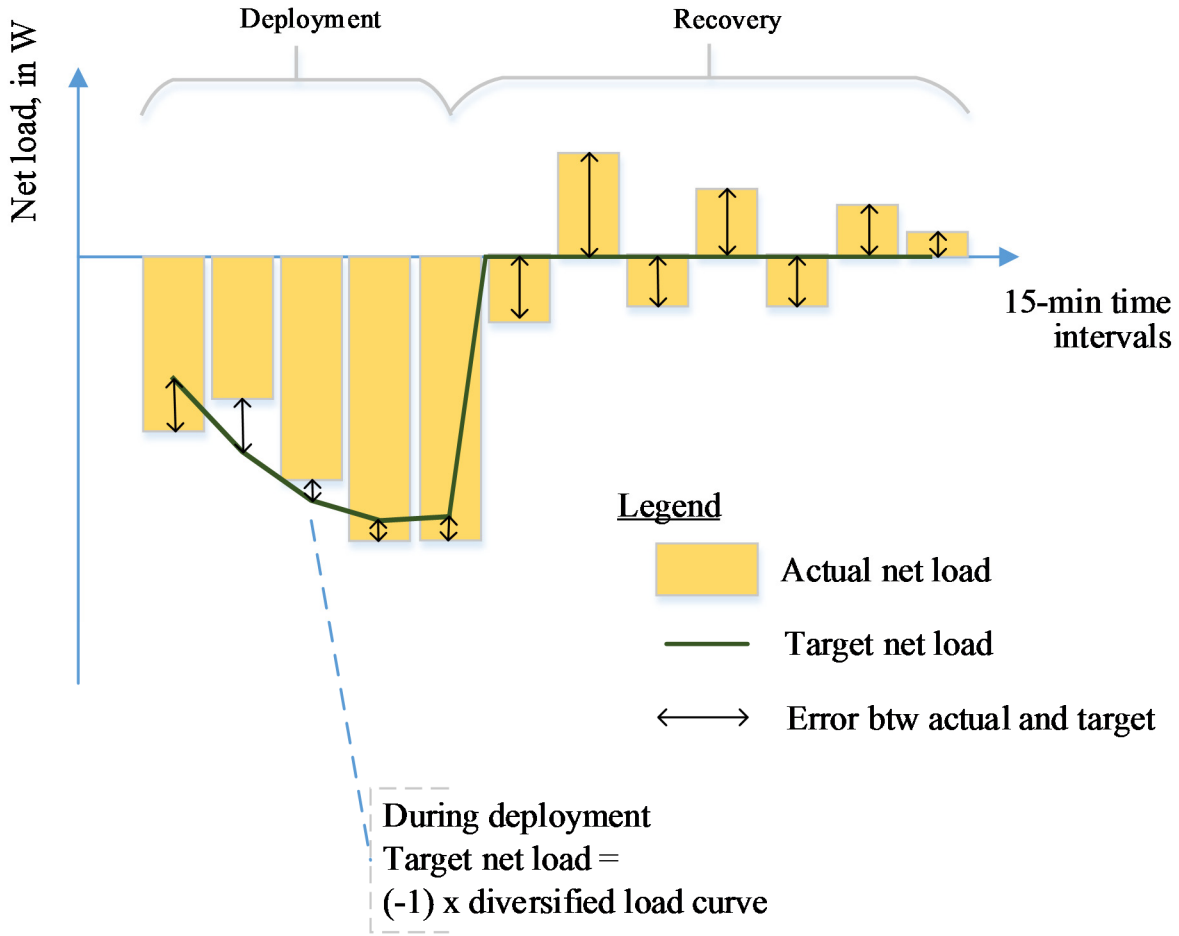
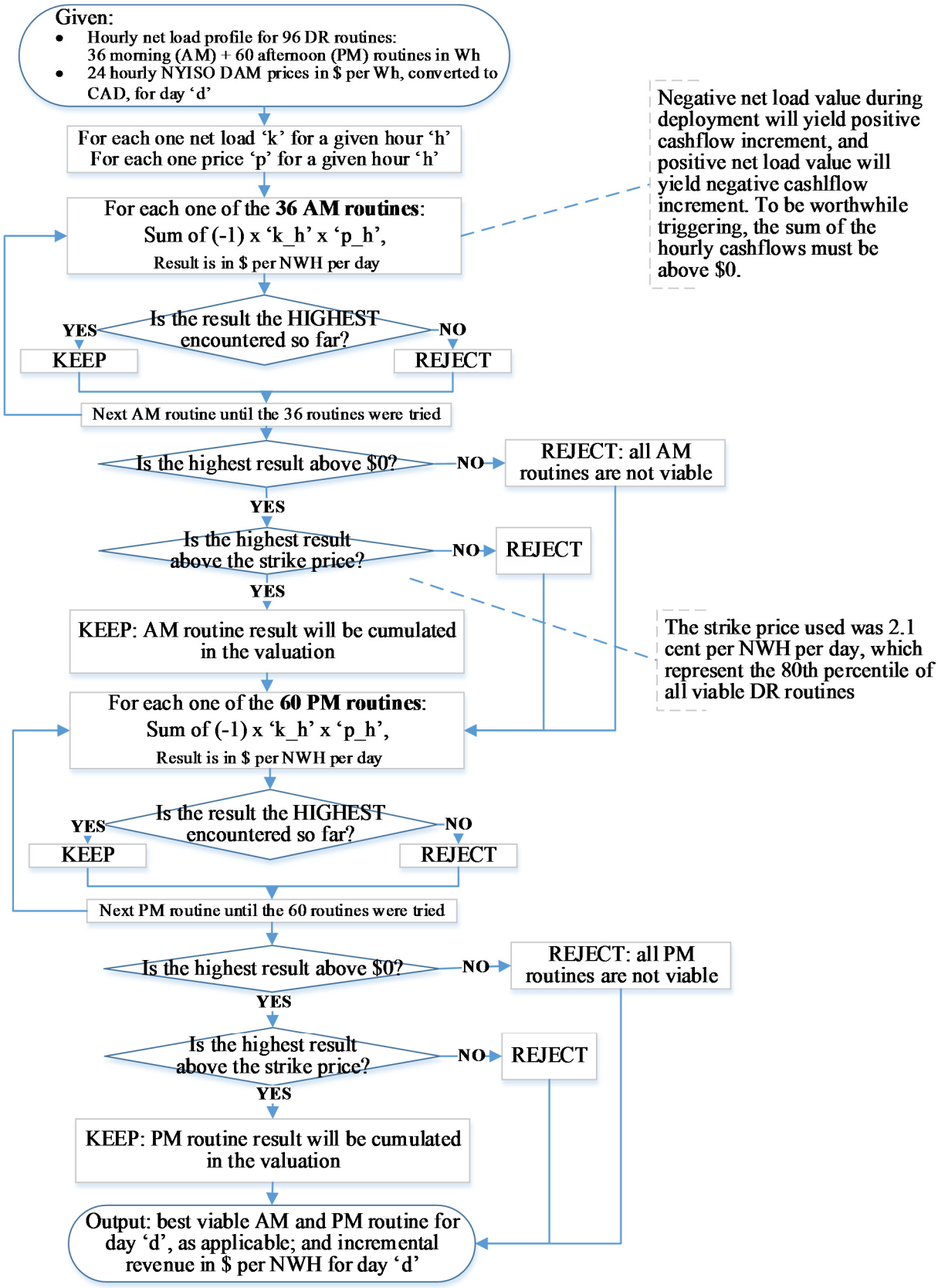


Illustration B-I Least Squared Mean Approach

The retained routine was the one DR routine with the "highest" curtailment, then "lowest" and "most constant" recovery. Whether a routine is better than another was determined through least mean squared error method. During deployment, the error is the difference between the normalized net load profile and natural diversified load for each interval, thus the method rewards high curtailment. During the recovery period, an error is the difference

between the normalized net load profile and zero, thereby the method rewards low recovery load. During both the deployment period and recovery period, the method naturally punishes outlying load thus favoring “constant” curves as a result.

Schedule 4: Revenue Maximization



Appendix C. DR Events with a 15-minute Resolution

Illustration B-I and Illustration B-II, below, show the same DR Events as Illustration 18 and Illustration 19, in Section 4.2, only that they show the curtailment using a 15-minute interval, which was the result of the optimization routine prior to being integrated in hourly data.

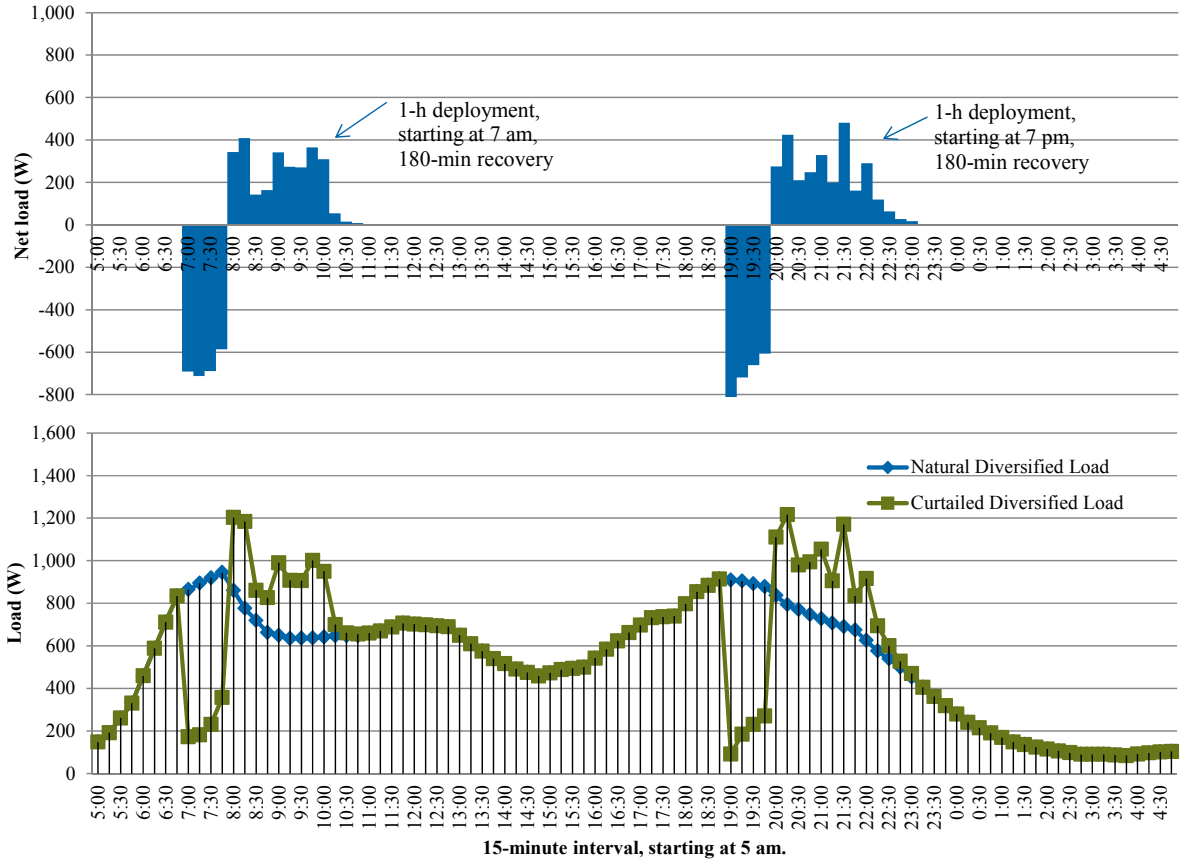


Illustration B-I: Highest Winter Morning and Afternoon Curtailment, Regardless of Timing or Duration, with a 15-Minute Interval

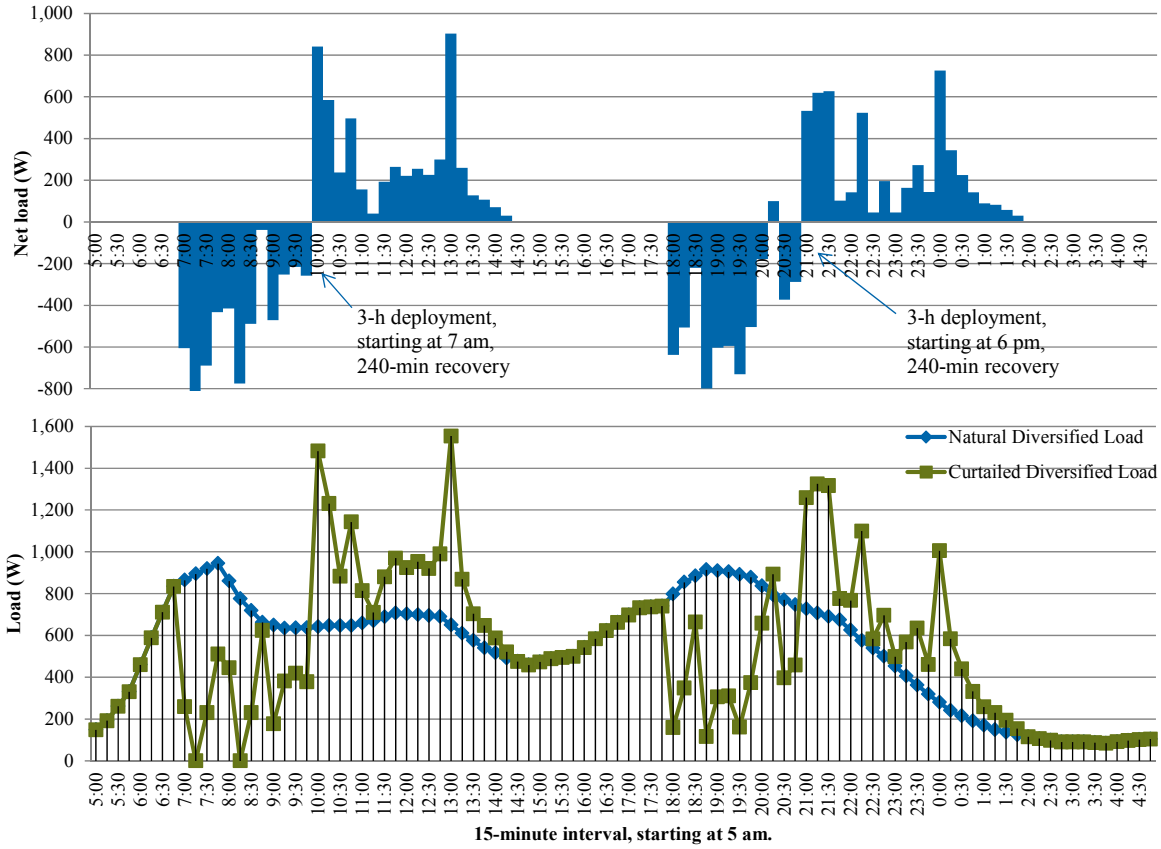


Illustration B-II: Highest Winter Morning and Afternoon Curtailment, with a 3-Hour Deployment, with a 15-Minute Interval

As expected, both Illustration B-I and Illustration B-II show that at higher degree of resolution the results of cycling optimization present a higher degree of variability than once it is integrated as hourly data. This is an issue that will have to be tackled through improving the cycling optimization method through the use of a superior numerical analysis method than the one used in the interest of this thesis. Nonetheless, the relatively unsophisticated approach that I developed showed that cycling is a viable approach to curtail the load of EWH while pacing the CLPU.

Appendix D. DR Event Opportunities Broken Down by DR Routine

Morning Peak Shifting		Count for 2013, 2014 & 2015	Winter	Lower Shoulder	Upper Shoulder	Lower Summer	Upper Summer
Stcl 01	60-min deploy't, starting at 6, 180-min recovery	2	2	0	0	0	0
Stcl 02	60-min deploy't, starting at 7, 180-min recovery	1	0	0	0	1	0
Stcl 03	60-min deploy't, starting at 8, 180-min recovery	0	0	0	0	0	0
Stcl 04	120-min deploy't, starting at 6, 240-min recovery	1	0	0	1	0	0
Stcl 05	120-min deploy't, starting at 7, 240-min recovery	0	0	0	0	0	0
Stcl 06	120-min deploy't, starting at 8, 240-min recovery	1	0	0	1	0	0
Stcl 07	180-min deploy't, starting at 6, 240-min recovery	56	38	2	13	0	3
Stcl 08	180-min deploy't, starting at 7, 240-min recovery	137	91	11	26	9	0
Stcl 09	180-min deploy't, starting at 8, 240-min recovery	379	147	133	69	25	5
Stcl 10	60-min deploy't, starting at 6, 120-min recovery	11	1	3	3	3	1
Stcl 11	60-min deploy't, starting at 7, 120-min recovery	5	1	2	1	1	0
Stcl 12	60-min deploy't, starting at 8, 120-min recovery	2	1	1	0	0	0
Stcl 13	120-min deploy't, starting at 6, 180-min recovery	13	6	0	6	0	1
Stcl 14	120-min deploy't, starting at 7, 180-min recovery	0	0	0	0	0	0
Stcl 15	120-min deploy't, starting at 8, 180-min recovery	0	0	0	0	0	0
Stcl 16	180-min deploy't, starting at 6, 180-min recovery	18	1	14	0	3	0
Stcl 17	180-min deploy't, starting at 7, 180-min recovery	62	4	56	1	0	1
Stcl 18	180-min deploy't, starting at 8, 180-min recovery	28	2	7	6	13	0
Stcl 19	60-min deploy't, starting at 6:30, 180-min recovery	0	0	0	0	0	0
Stcl 20	60-min deploy't, starting at 7:30, 180-min recovery	0	0	0	0	0	0
Stcl 21	60-min deploy't, starting at 8:30, 180-min recovery	0	0	0	0	0	0
Stcl 22	120-min deploy't, starting at 5:30, 240-min recovery	1	0	0	1	0	0
Stcl 23	120-min deploy't, starting at 6:30, 240-min recovery	0	0	0	0	0	0
Stcl 24	120-min deploy't, starting at 7:30, 240-min recovery	0	0	0	0	0	0
Stcl 25	180-min deploy't, starting at 5:30, 240-min recovery	1	0	1	0	0	0
Stcl 26	180-min deploy't, starting at 6:30, 240-min recovery	62	60	2	0	0	0
Stcl 27	180-min deploy't, starting at 7:30, 240-min recovery	0	0	0	0	0	0
Stcl 28	45-min deploy't, starting at 6, 165-min recovery	1	1	0	0	0	0
Stcl 29	45-min deploy't, starting at 7, 165-min recovery	1	0	0	1	0	0
Stcl 30	45-min deploy't, starting at 8, 165-min recovery	0	0	0	0	0	0
Stcl 31	90-min deploy't, starting at 6, 210-min recovery	2	0	1	0	1	0
Stcl 32	90-min deploy't, starting at 7, 210-min recovery	0	0	0	0	0	0
Stcl 33	90-min deploy't, starting at 8, 210-min recovery	0	0	0	0	0	0
Stcl 34	150-min deploy't, starting at 6, 210-min recovery	7	0	0	2	5	0
Stcl 35	150-min deploy't, starting at 7, 210-min recovery	1	0	1	0	0	0
Stcl 36	150-min deploy't, starting at 8, 210-min recovery	3	1	0	2	0	0
None AM		300	10	30	44	71	145
Total - Morning		1,095	366	264	177	132	156

Afternoon/Evening Peak Shifting							
Stcl 37	60-min deploy't, starting at 16, 180-min recovery	0	0	0	0	0	0
Stcl 38	60-min deploy't, starting at 17, 180-min recovery	1	0	1	0	0	0
Stcl 39	60-min deploy't, starting at 18, 180-min recovery	0	0	0	0	0	0
Stcl 40	60-min deploy't, starting at 19, 180-min recovery	0	0	0	0	0	0
Stcl 41	60-min deploy't, starting at 20, 180-min recovery	0	0	0	0	0	0
Stcl 42	120-min deploy't, starting at 16, 240-min recovery	1	0	0	0	1	0
Stcl 43	120-min deploy't, starting at 17, 240-min recovery	2	0	2	0	0	0
Stcl 44	120-min deploy't, starting at 18, 240-min recovery	4	0	0	4	0	0
Stcl 45	120-min deploy't, starting at 19, 240-min recovery	5	5	0	0	0	0
Stcl 46	120-min deploy't, starting at 20, 240-min recovery	0	0	0	0	0	0
Stcl 47	180-min deploy't, starting at 16, 240-min recovery	17	2	0	4	4	7
Stcl 48	180-min deploy't, starting at 17, 240-min recovery	118	0	80	17	4	17
Stcl 49	180-min deploy't, starting at 18, 240-min recovery	54	38	0	2	5	9
Stcl 50	180-min deploy't, starting at 19, 240-min recovery	12	1	0	10	0	1
Stcl 51	180-min deploy't, starting at 20, 240-min recovery	1	1	0	0	0	0
Stcl 52	60-min deploy't, starting at 16, 120-min recovery	1	0	0	0	1	0
Stcl 53	60-min deploy't, starting at 17, 120-min recovery	0	0	0	0	0	0
Stcl 54	60-min deploy't, starting at 18, 120-min recovery	0	0	0	0	0	0
Stcl 55	60-min deploy't, starting at 19, 120-min recovery	0	0	0	0	0	0
Stcl 56	60-min deploy't, starting at 20, 120-min recovery	0	0	0	0	0	0
Stcl 57	120-min deploy't, starting at 16, 180-min recovery	1	1	0	0	0	0
Stcl 58	120-min deploy't, starting at 17, 180-min recovery	0	0	0	0	0	0
Stcl 59	120-min deploy't, starting at 18, 180-min recovery	1	0	0	0	1	0
Stcl 60	120-min deploy't, starting at 19, 180-min recovery	0	0	0	0	0	0
Stcl 61	120-min deploy't, starting at 20, 180-min recovery	0	0	0	0	0	0
Stcl 62	180-min deploy't, starting at 16, 180-min recovery	3	0	1	0	2	0
Stcl 63	180-min deploy't, starting at 17, 180-min recovery	4	2	0	1	0	1
Stcl 64	180-min deploy't, starting at 18, 180-min recovery	13	10	0	3	0	0
Stcl 65	180-min deploy't, starting at 19, 180-min recovery	62	43	9	0	0	10
Stcl 66	180-min deploy't, starting at 20, 180-min recovery	92	0	0	31	7	54
Stcl 67	60-min deploy't, starting at 16:30, 180-min recovery	0	0	0	0	0	0
Stcl 68	60-min deploy't, starting at 17:30, 180-min recovery	0	0	0	0	0	0
Stcl 69	60-min deploy't, starting at 18:30, 180-min recovery	0	0	0	0	0	0
Stcl 70	60-min deploy't, starting at 19:30, 180-min recovery	0	0	0	0	0	0
Stcl 71	60-min deploy't, starting at 20:30, 180-min recovery	0	0	0	0	0	0
Stcl 72	120-min deploy't, starting at 15:30, 240-min recovery	1	0	0	0	1	0
Stcl 73	120-min deploy't, starting at 16:30, 240-min recovery	0	0	0	0	0	0
Stcl 74	120-min deploy't, starting at 17:30, 240-min recovery	0	0	0	0	0	0
Stcl 75	120-min deploy't, starting at 18:30, 240-min recovery	0	0	0	0	0	0
Stcl 76	120-min deploy't, starting at 19:30, 240-min recovery	0	0	0	0	0	0
Stcl 77	180-min deploy't, starting at 15:30, 240-min recovery	5	0	1	0	0	4
Stcl 78	180-min deploy't, starting at 16:30, 240-min recovery	86	35	0	1	0	50
Stcl 79	180-min deploy't, starting at 17:30, 240-min recovery	18	0	0	5	11	2
Stcl 80	180-min deploy't, starting at 18:30, 240-min recovery	158	5	18	99	35	1
Stcl 81	180-min deploy't, starting at 19:30, 240-min recovery	175	0	149	0	26	0
Stcl 82	45-min deploy't, starting at 16, 165-min recovery	0	0	0	0	0	0
Stcl 83	45-min deploy't, starting at 17, 165-min recovery	0	0	0	0	0	0
Stcl 84	45-min deploy't, starting at 18, 165-min recovery	0	0	0	0	0	0
Stcl 85	45-min deploy't, starting at 19, 165-min recovery	0	0	0	0	0	0
Stcl 86	45-min deploy't, starting at 20, 165-min recovery	0	0	0	0	0	0
Stcl 87	90-min deploy't, starting at 16, 225-min recovery	0	0	0	0	0	0
Stcl 88	90-min deploy't, starting at 17, 225-min recovery	0	0	0	0	0	0
Stcl 89	90-min deploy't, starting at 18, 225-min recovery	0	0	0	0	0	0
Stcl 90	90-min deploy't, starting at 19, 225-min recovery	0	0	0	0	0	0
Stcl 91	90-min deploy't, starting at 20, 225-min recovery	0	0	0	0	0	0
Stcl 92	150-min deploy't, starting at 16, 225-min recovery	6	1	3	0	2	0
Stcl 93	150-min deploy't, starting at 17, 225-min recovery	0	0	0	0	0	0
Stcl 94	150-min deploy't, starting at 18, 225-min recovery	187	187	0	0	0	0
Stcl 95	150-min deploy't, starting at 19, 225-min recovery	32	0	0	0	32	0
Stcl 96	150-min deploy't, starting at 20, 225-min recovery	35	35	0	0	0	0
None PM		0	0	0	0	0	0
Total -- Afternoon		1,095	366	264	177	132	156

Appendix E. DR Event Opportunities Broken Down by DR Routine, for Top-Quintile DR Events

Mo ng Peak Shifting		Count for 2013, 2014 & 20	Wint	Lower Should	Upper Should	Lower Summ	Upper Summ
Stcl 01	60-min deploy't, starting at 6, 180-min recovery	0	0	0	0	0	0
Stcl 02	60-min deploy't, starting at 7, 180-min recovery	0	0	0	0	0	0
Stcl 03	60-min deploy't, starting at 8, 180-min recovery	0	0	0	0	0	0
Stcl 04	120-min deploy't, starting at 6, 240-min recovery	0	0	0	0	0	0
Stcl 05	120-min deploy't, starting at 7, 240-min recovery	0	0	0	0	0	0
Stcl 06	120-min deploy't, starting at 8, 240-min recovery	0	0	0	0	0	0
Stcl 07	180-min deploy't, starting at 6, 240-min recovery	10	10	0	0	0	0
Stcl 08	180-min deploy't, starting at 7, 240-min recovery	34	34	0	0	0	0
Stcl 09	180-min deploy't, starting at 8, 240-min recovery	19	18	1	0	0	0
Stcl 10	60-min deploy't, starting at 6, 120-min recovery	0	0	0	0	0	0
Stcl 11	60-min deploy't, starting at 7, 120-min recovery	0	0	0	0	0	0
Stcl 12	60-min deploy't, starting at 8, 120-min recovery	0	0	0	0	0	0
Stcl 13	120-min deploy't, starting at 6, 180-min recovery	1	1	0	0	0	0
Stcl 14	120-min deploy't, starting at 7, 180-min recovery	0	0	0	0	0	0
Stcl 15	120-min deploy't, starting at 8, 180-min recovery	0	0	0	0	0	0
Stcl 16	180-min deploy't, starting at 6, 180-min recovery	0	0	0	0	0	0
Stcl 17	180-min deploy't, starting at 7, 180-min recovery	3	0	3	0	0	0
Stcl 18	180-min deploy't, starting at 8, 180-min recovery	0	0	0	0	0	0
Stcl 19	60-min deploy't, starting at 6:30, 180-min recovery	0	0	0	0	0	0
Stcl 20	60-min deploy't, starting at 7:30, 180-min recovery	0	0	0	0	0	0
Stcl 21	60-min deploy't, starting at 8:30, 180-min recovery	0	0	0	0	0	0
Stcl 22	120-min deploy't, starting at 5:30, 240-min recovery	0	0	0	0	0	0
Stcl 23	120-min deploy't, starting at 6:30, 240-min recovery	0	0	0	0	0	0
Stcl 24	120-min deploy't, starting at 7:30, 240-min recovery	0	0	0	0	0	0
Stcl 25	180-min deploy't, starting at 5:30, 240-min recovery	0	0	0	0	0	0
Stcl 26	180-min deploy't, starting at 6:30, 240-min recovery	48	48	0	0	0	0
Stcl 27	180-min deploy't, starting at 7:30, 240-min recovery	0	0	0	0	0	0
Stcl 28	45-min deploy't, starting at 6, 165-min recovery	0	0	0	0	0	0
Stcl 29	45-min deploy't, starting at 7, 165-min recovery	0	0	0	0	0	0
Stcl 30	45-min deploy't, starting at 8, 165-min recovery	0	0	0	0	0	0
Stcl 31	90-min deploy't, starting at 6, 210-min recovery	0	0	0	0	0	0
Stcl 32	90-min deploy't, starting at 7, 210-min recovery	0	0	0	0	0	0
Stcl 33	90-min deploy't, starting at 8, 210-min recovery	0	0	0	0	0	0
Stcl 34	150-min deploy't, starting at 6, 210-min recovery	0	0	0	0	0	0
Stcl 35	150-min deploy't, starting at 7, 210-min recovery	0	0	0	0	0	0
Stcl 36	150-min deploy't, starting at 8, 210-min recovery	0	0	0	0	0	0
Total - Morning		115	111	4	0	0	0

Afternoon/Evening Peak Shifting							
Stcl 37	60-min deploy't, starting at 16, 180-min recovery	0	0	0	0	0	0
Stcl 38	60-min deploy't, starting at 17, 180-min recovery	0	0	0	0	0	0
Stcl 39	60-min deploy't, starting at 18, 180-min recovery	0	0	0	0	0	0
Stcl 40	60-min deploy't, starting at 19, 180-min recovery	0	0	0	0	0	0
Stcl 41	60-min deploy't, starting at 20, 180-min recovery	0	0	0	0	0	0
Stcl 42	120-min deploy't, starting at 16, 240-min recovery	0	0	0	0	0	0
Stcl 43	120-min deploy't, starting at 17, 240-min recovery	1	0	1	0	0	0
Stcl 44	120-min deploy't, starting at 18, 240-min recovery	0	0	0	0	0	0
Stcl 45	120-min deploy't, starting at 19, 240-min recovery	3	3	0	0	0	0
Stcl 46	120-min deploy't, starting at 20, 240-min recovery	0	0	0	0	0	0
Stcl 47	180-min deploy't, starting at 16, 240-min recovery	1	1	0	0	0	0
Stcl 48	180-min deploy't, starting at 17, 240-min recovery	45	0	41	3	0	1
Stcl 49	180-min deploy't, starting at 18, 240-min recovery	19	19	0	0	0	0
Stcl 50	180-min deploy't, starting at 19, 240-min recovery	0	0	0	0	0	0
Stcl 51	180-min deploy't, starting at 20, 240-min recovery	0	0	0	0	0	0
Stcl 52	60-min deploy't, starting at 16, 120-min recovery	0	0	0	0	0	0
Stcl 53	60-min deploy't, starting at 17, 120-min recovery	0	0	0	0	0	0
Stcl 54	60-min deploy't, starting at 18, 120-min recovery	0	0	0	0	0	0
Stcl 55	60-min deploy't, starting at 19, 120-min recovery	0	0	0	0	0	0
Stcl 56	60-min deploy't, starting at 20, 120-min recovery	0	0	0	0	0	0
Stcl 57	120-min deploy't, starting at 16, 180-min recovery	0	0	0	0	0	0
Stcl 58	120-min deploy't, starting at 17, 180-min recovery	0	0	0	0	0	0
Stcl 59	120-min deploy't, starting at 18, 180-min recovery	0	0	0	0	0	0
Stcl 60	120-min deploy't, starting at 19, 180-min recovery	0	0	0	0	0	0
Stcl 61	120-min deploy't, starting at 20, 180-min recovery	0	0	0	0	0	0
Stcl 62	180-min deploy't, starting at 16, 180-min recovery	1	0	0	0	1	0
Stcl 63	180-min deploy't, starting at 17, 180-min recovery	1	1	0	0	0	0
Stcl 64	180-min deploy't, starting at 18, 180-min recovery	2	2	0	0	0	0
Stcl 65	180-min deploy't, starting at 19, 180-min recovery	15	15	0	0	0	0
Stcl 66	180-min deploy't, starting at 20, 180-min recovery	0	0	0	0	0	0
Stcl 67	60-min deploy't, starting at 16:30, 180-min recovery	0	0	0	0	0	0
Stcl 68	60-min deploy't, starting at 17:30, 180-min recovery	0	0	0	0	0	0
Stcl 69	60-min deploy't, starting at 18:30, 180-min recovery	0	0	0	0	0	0
Stcl 70	60-min deploy't, starting at 19:30, 180-min recovery	0	0	0	0	0	0
Stcl 71	60-min deploy't, starting at 20:30, 180-min recovery	0	0	0	0	0	0
Stcl 72	120-min deploy't, starting at 15:30, 240-min recovery	0	0	0	0	0	0
Stcl 73	120-min deploy't, starting at 16:30, 240-min recovery	0	0	0	0	0	0
Stcl 74	120-min deploy't, starting at 17:30, 240-min recovery	0	0	0	0	0	0
Stcl 75	120-min deploy't, starting at 18:30, 240-min recovery	0	0	0	0	0	0
Stcl 76	120-min deploy't, starting at 19:30, 240-min recovery	0	0	0	0	0	0
Stcl 77	180-min deploy't, starting at 15:30, 240-min recovery	1	0	0	0	0	1
Stcl 78	180-min deploy't, starting at 16:30, 240-min recovery	26	21	0	0	0	5
Stcl 79	180-min deploy't, starting at 17:30, 240-min recovery	1	0	0	0	1	0
Stcl 80	180-min deploy't, starting at 18:30, 240-min recovery	8	1	2	5	0	0
Stcl 81	180-min deploy't, starting at 19:30, 240-min recovery	5	0	5	0	0	0
Stcl 82	45-min deploy't, starting at 16, 165-min recovery	0	0	0	0	0	0
Stcl 83	45-min deploy't, starting at 17, 165-min recovery	0	0	0	0	0	0
Stcl 84	45-min deploy't, starting at 18, 165-min recovery	0	0	0	0	0	0
Stcl 85	45-min deploy't, starting at 19, 165-min recovery	0	0	0	0	0	0
Stcl 86	45-min deploy't, starting at 20, 165-min recovery	0	0	0	0	0	0
Stcl 87	90-min deploy't, starting at 16, 225-min recovery	0	0	0	0	0	0
Stcl 88	90-min deploy't, starting at 17, 225-min recovery	0	0	0	0	0	0
Stcl 89	90-min deploy't, starting at 18, 225-min recovery	0	0	0	0	0	0
Stcl 90	90-min deploy't, starting at 19, 225-min recovery	0	0	0	0	0	0
Stcl 91	90-min deploy't, starting at 20, 225-min recovery	0	0	0	0	0	0
Stcl 92	150-min deploy't, starting at 16, 225-min recovery	1	0	1	0	0	0
Stcl 93	150-min deploy't, starting at 17, 225-min recovery	0	0	0	0	0	0
Stcl 94	150-min deploy't, starting at 18, 225-min recovery	129	129	0	0	0	0
Stcl 95	150-min deploy't, starting at 19, 225-min recovery	0	0	0	0	0	0
Stcl 96	150-min deploy't, starting at 20, 225-min recovery	4	4	0	0	0	0
Total -- Afternoon		263	196	50	8	2	7

Appendix F. CBA Cashflow Table

All in real CAD $.

(A) Inputs

Primary, technical assumptions	
Number of participants	100,000
Persistence in the program (Year)	9 yr
Discount rate (Real)	3.579%
Inflation (FYI)	2.000%
Curtailment achieved per participant (kW)	0.7
Net-to-gross ratio (%)	100%
T&D losses	7.9%
Planning reserve margin	11.1%
Costs	
Program-admin expenses per participant-yr	$10.00
Program-admin capital cost ($,000, fixed)	$5,400
Financial incentive per participant-yr	$30.00
DR measure cost, PA contribution, per p. (variable)	$126.00
DR measure cost, participant contribution, per p.	$0.00
Participant transaction costs, per participant	$23.91
Participant value of lost service, per p.-yr	$22.50
Increased energy consumption per p.-yr	$0.00
Lost revenues to the utility per p.-yr	$0.00
Environmental compliance costs per p.-yr	$0.00
Environmental externalities per p.-yr	$0.00

Benefits	
Avoided capacity cost, Yr 3 and onward ($/kW-yr)	$106.00
Avoided capacity cost, Yr 1 & 2 ($/kW-yr)	$20.00
Avoided energy cost per participant per year	$0.00
Avoided transmission cost ($/kW-yr)	$23.60
Avoided distribution cost ($/kW-yr)	$8.55
Avoided ancillary service costs per p. per yr	$0.00
Revenues from wholesale DR programs per p.-yr	$9.95
Market price suppression effect per p.-yr	$0.00
Avoided environmental compliance costs	$0.00
Avoided environmental externalities	$0.00
Participant bill savings per p.-yr (loss revenues)	same
Financial incentive to participant per p.-yr	same
Tax credit	$0.00
Other benefits	$0.00

(C) Outputs ($'000,000 unless specified, in present value)

Participant Cost Test (PCT):						
Benefits (m$):	$23.6	B/C Ratio:	1.17			
Cost (m$):	$20.1	NPV (m$):	$3.5			
Program Administrator Cost Test (PAC):						
Benefits (m$):	$81.8	B/C Ratio:	1.66	Levelized Cost:	$82.79	($/kW-yr)
Cost (m$):	$49.4	NPV (m$):	$32.4	Net Lev. Cost	-$54.34	($/kW-yr)
Rate-Impact Measure Cost Test (RIM):						
Benefits (m$):	$81.8	B/C Ratio:	1.66			
Cost (m$):	$49.4	NPV (m$):	$32.4			
Total Resource Cost Test (TRC):						
Benefits (m$):	$81.8	B/C Ratio:	1.78	Levelized Cost:	$76.93	($/kW-yr)
Cost (m$):	$45.9	NPV (m$):	$35.9	Net Lev. Cost	-$60.20	($/kW-yr)
Societal Cost Test (SCT):						
Benefits (m$):	$73.7	B/C Ratio:	1.60			
Cost (m$):	$45.9	NPV (m$):	$27.8			

(B) Cashflows Table ($'000)

	PV	Present	Year 01	Year 02	Year 03	Year 04	Year 05	Year 06	Year 07	Year 08	Year 09	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Costs																						
Program administrator expenses	**$7,851**		$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program administrator capital cost	**$5,400**	$5,400																				
Financial incentive for participant	**$23,554**		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DR measure cost, prog. administator contrib'n	**$12,600**	$12,600																				
DR measure cost, participant contribution	**$0**	$0																				
Participant transaction cost	**$2,391**	$2,391																				
Participant value of lost of service	**$17,665**		$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increased energy consumption	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lost revenues to the Utility	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Environmental compliance costs	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Environmental externalities	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Benefits																						
Avoided capacity costs	**$56,001**		$1,689	$1,689	$8,951	$8,951	$8,951	$8,951	$8,951	$8,951	$8,951	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided energy costs	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided transmission costs	**$12,970**		$1,652	$1,652	$1,652	$1,652	$1,652	$1,652	$1,652	$1,652	$1,652	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided distribution costs	**$4,699**		$599	$599	$599	$599	$599	$599	$599	$599	$599	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided ancillary service cost	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Revenues from wholesale DR programs	**$8,160**		$1,003	$1,010	$1,007	$1,014	$1,025	$1,047	$1,067	$1,094	$1,117	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market-price suppression effect	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided environmental compliance costs	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided environmental externalities	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Participant bill savings	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Financial incentive to participant	**$23,554**		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tax credits	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other benefits	**$0**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Curtailment w/ T&D (MW)	**597**		76	76	76	76	76	76	76	76	76	0	0	0	0	0	0	0	0	0	0	0