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Demand Response in the Ontario Electricity Market

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Abstract

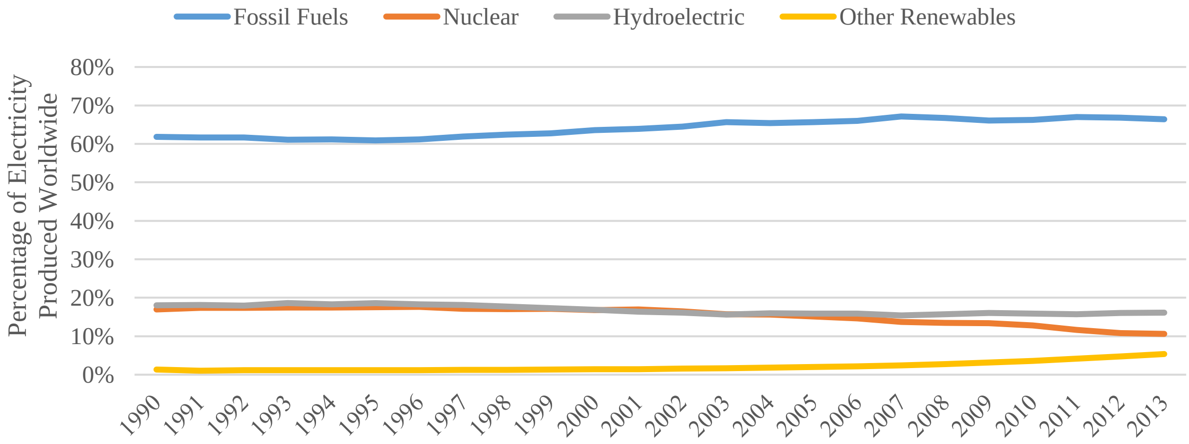
In order to address the issue of climate change, our energy systems need to incorporate higher percentages of renewable energy generation. There are, however, unique challenges associated with this task. Although the marginal cost of renewable energy sources is at or near zero, renewables introduce a level of variability into the supply of electricity that is forcing electricity system operators to become more sophisticated in how they operate the electricity system. By more actively managing the demand for electricity through what is called demand response, some of the increased variability in the electricity supply due to higher percentages of renewables might be effectively mitigated by decreasing the variability in the demand for electricity. While various forms of demand response have existed for decades, technological improvements are increasing the usefulness and amount of demand response available to grid operators. This paper models Ontario's electricity market for the year of 2014 and examines the effect of demand response at various levels of wind penetration in the electricity supply mix. The inclusion of demand response into the model introduces cost savings over the case with no demand response. Demand response decreases the need for conventional peaking sources and reduces the amount of excess electricity generation, making it easier for grid operators to incorporate a higher penetration of renewable energy sources.

1 Introduction

Finally, the debate surrounding climate change has shifted from whether or not it is occurring to when we will see the worst of its effects and, further, to what we can (and must) do to ensure that humans can continue to live on a hospitable planet. While carbon capture technology is promising (Viebahn et al., 2007), our ability to transition from a fossil fuel based economy to one of renewable energy sources is an essential part of the global greenhouse gas (GHG) reduction strategy (Hoffert et al., 2002). Human innovation and engineering prowess, in combination with currently available technology are facilitating this transition, however, there are significant challenges at every step.

As seen in Figure 1, the world's energy supply mix has not changed significantly. The amount of electricity generated by fossil fuels is higher than it was in 1990, both in absolute and relative terms. Countries like China and India have seen aggressive growth in their electricity generation capacities and significant amounts of renewable generation have been added as a result, however, the net effect on the supply mix has been somewhat inconsequential.

Figure 1: World electricity production by generation type[1]



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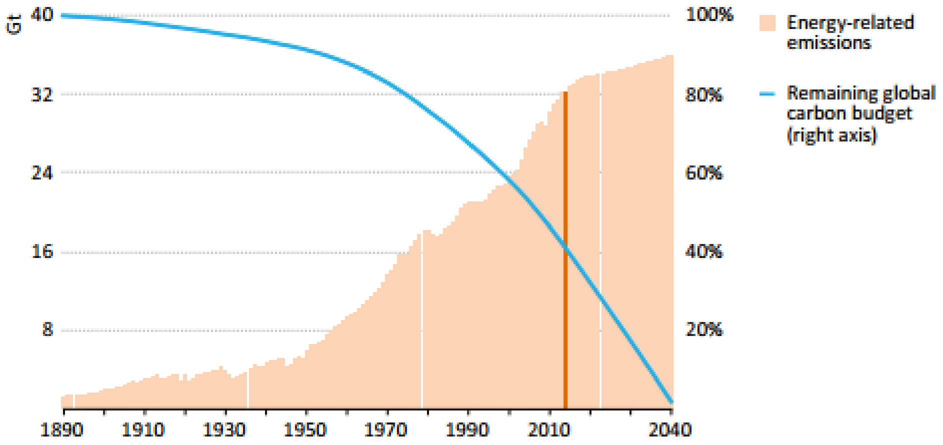
[1] Source: World Bank (2014)

The increase in the level of wind, solar, and other new renewable energy types has largely come at the expense of additional nuclear generation penetration. It is worth noting, however, that the previous few years have seen a stagnation of the growth of fossil fuel penetration.

Figure 2 shows projections of global energy-related CO_2 emissions and the world's remaining carbon budget. According to the International Energy Agency (2015), 2014 saw the fastest growth of renewables, accounting for 45% of the world's net addition to generation capacity, however, it is still not likely aggressive enough to mitigate the worst of climate change. Part of this slow integration is due to the fact that integrating large amounts of renewables into our energy system in a short period of time is a difficult task.

Figure 2: Global energy-related CO_2 emissions and remaining carbon budget for a >50% change of limiting the global temperature rise to 2°C[2]



There are characteristics distinct to renewable energy – explained later on – that are challenging our understanding of how to best operate the electricity grid. As a result, there is an abundance of literature attempting to answer the various technical and economic aspects of how

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[2] Source: IEA (2015)
Note: The left Y axis measures Gigatonnes of CO_2 and the right Y axis is the percentage of the remaining carbon budget.

we might best integrate increasing amounts of renewable electricity generation. Ranging from the optimal construction of a new, interstate electricity system in the United States (MacDonald et al., 2016) to small-scale microgrids (Mohamed Abd el Motaleb et al., 2016) to a significant decentralization of electricity production (Rifkin, 2011), efforts are well underway to determine how we might best integrate renewable energy sources like wind and solar, while maintaining the same level of quality within the electricity system that we enjoy today.

The current paper presents a mathematical model of Ontario's electricity market. Although simple in its construction, the model provides a basis for which a discussion of the effects of demand-side management of the electricity market on the integration of renewable energy sources can take place. The remainder of the paper is structured as follows. Section 1.1 gives a brief overview of Ontario's electricity market. Section 1.2 discusses in greater detail the challenges of renewables and some of the options available to mitigate these challenges. Section 1.3 defines and discusses demand-side management, otherwise known as demand response. Section 2 presents the data and methodology used for the construction of the model. Section 3 presents the results of the model alongside some potential implications for government policy. Section 4 offers a discussion of the results. Section 5 discusses the limitations of the model and future research opportunities. Section 6 draws some conclusions.

1.1 Ontario's Electricity Market

In order to fully understand the challenges posed by increasing levels of renewable penetration, we must first understand how the electricity market works.[3] The most basic idea is that power plants supply enough electricity to the system such that the demand for electricity is

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[3] The model presented in the paper is based on data from Ontario's electricity market, so the explanation of how the electricity market functions is specific to Ontario.

always met. In order to remain functional, the amount of electricity on the grid must be maintained within a certain range at all times. As far as most consumers in Ontario are concerned, this results in a constant supply of 120V at 60Hz at your typical household outlet.[4] Unlike most goods markets where products can be mass produced and stored in warehouses until needed, large amounts of electricity cannot be reliably stored for long periods of time. Consequently, the supply of and demand for electricity must be kept in constant equilibrium, otherwise the grid can suffer blackouts and potential damage to its components.

The responsibility of ensuring Ontario's electricity market functions correctly falls upon the crown corporation, the Independent Electricity System Operator (IESO). Its main roles include: balancing the supply of and demand for electricity and controlling its transmission throughout the province; medium- and long-term planning for the province's energy needs; overseeing the electricity wholesale market where the market price of electricity is set; and encouraging energy conservation through a variety of programs (IESO, 2016a). The first two roles are the most relevant with respect to the challenges of integrating large amounts of renewable energy into the electricity system. On an operational basis, the IESO forecasts an uncertain electricity demand throughout the province every five minutes and directs suppliers to provide the required amount of electricity to meet that demand. On a strategic basis, it must ensure that Ontario's generation mix is able to meet these requirements for years to come. High levels of renewable penetration significantly complicates these roles.

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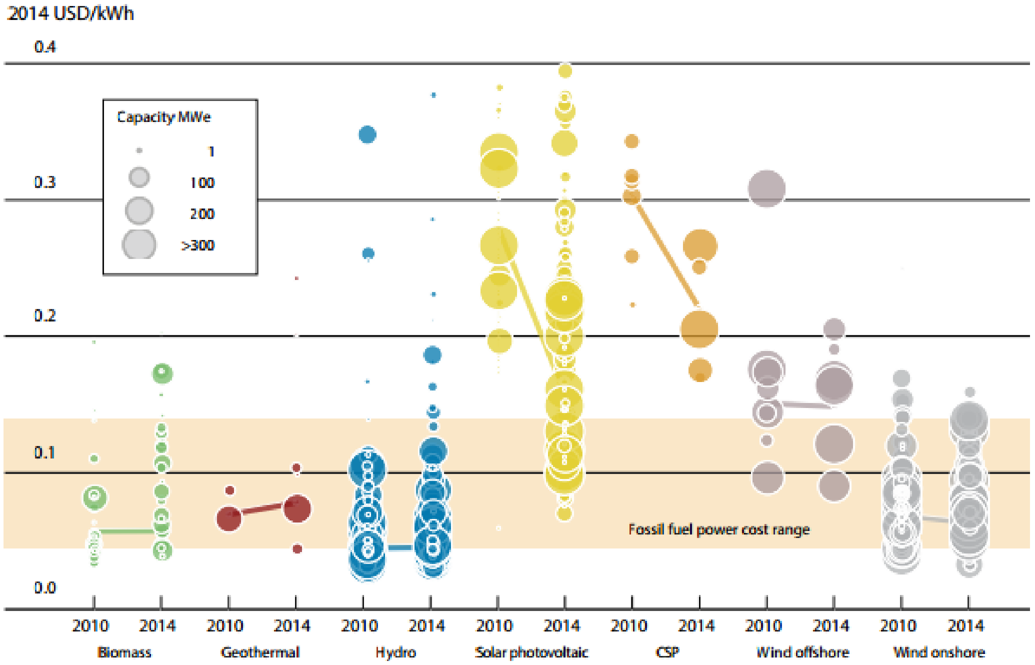
[4] Of course, different parts of the electricity transmission chain are rated for different amounts of electricity, but the details of such are not integral for a basic understanding of how the electricity market works in the context of renewable energy penetration.

1.2 Renewable Energy and its Challenges

The marginal costs of electricity generation from wind and solar plants have always been at or near zero, however, the capital costs of plant construction have been somewhat prohibitive. Steady improvements in renewable energy technologies, in combination with improved production techniques, have made the prospect of energy production via these means increasingly cost competitive. According to the International Renewable Energy Agency (2015), the total cost of renewable energy production in many parts of the world is now either below or at parity with the cost of conventional sources. Figure 3 illustrates the decline in the levelized cost of electricity (LCOE)[5] from 2010 to 2014 of various renewable technologies.

Figure 3: The levelized cost of electricity from utility-scale renewable technologies, 2010–2014[6]



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[5] The LCOE is the ratio of lifetime costs to lifetime electricity generation, discounted back to a common year using a rate that reflects the average cost of capital.

[6] Source: IRENA (2015)
Note: Size of the diameter of the circle represents the size of the project. The centre of each circle is the value for the cost of each project on the Y axis. Real weighted average cost of capital is 7.5% in OECD countries and China; 10% in the rest of the world.

While the capital costs have become more favourable in recent years, de Sisternes et al. (2016) point out that the marginal value of these variable renewable resources declines at higher penetrations due to four factors. First, as renewable penetration increases, the energy generated displaces energy from sources with progressively lower marginal costs, reducing the total value added to the system. Second, the variability of the wind and sun – and to a lesser extent, water levels for hydroelectric generation – mean that the potential for renewables to contribute to peak electricity demand is limited and their marginal contribution declines at higher penetrations. Third, renewable energy curtailment increases at higher penetrations, thereby reducing the effective capacity of these resources. The effect of curtailment is similar to that of gas flaring, in that operators purposely wastes resources to maintain the stability of the system. Lastly, higher penetrations of renewables increases the demand for flexible operating reserves that can respond to the increased variability and uncertainty of the system.

In order to better understand these challenges, let us compare and contrast typical sources of power generation. Historically, conventional power sources have allowed us to generate electricity as we need it. That is, they are dispatchable – they do not take long to start or stop generating power – and can be relied upon to generate specific amounts of electricity at specific time intervals. This is most true with respect to fossil fuel power plants, meaning they provide the most flexibility for electricity system operators to balance electricity supply and demand, but also nuclear and hydroelectric with some caveats. Power plant operators are able to reliably change the amount of electrical output from these sources and the fuel for combustion, nuclear and some hydroelectric power plants can be stored, thereby increasing the certainty of availability of the resources used to generate electricity by these means.

In Ontario, nuclear is typically used to provide baseload[7] power because it is a fairly long and complicated process to start and stop nuclear reactions in a controlled and safe manner, however, there are some manoeuvring capabilities available:

> The amount of reduction available for reactor power manoeuvres is dependent upon the reactivity of the unit at the time and can vary. Initial manoeuvres can be performed with approximately 30 minutes notice and can only be performed on one unit at time. Reductions on multiple units must take place sequentially, not simultaneously. If a further reduction must be achieved on a unit that has already been reduced, between 8 and 12 hours must elapse after the first manoeuvre has taken place before another can be initiated. (IESO, 2011)

The IESO can dispatch 2,400MW of the approximately 13,000MW of total nuclear generation capacity, 300MW at a time. A further reduction, such as a shutdown, requires nuclear reactors to remain offline for between 48 and 96 hours (Ibid.). Nuclear generation can then be described as an energy source which adds a significant amount of reliability into the supply of electricity, with medium- and long-term dispatch capabilities.[8]

Similar to nuclear, much of the hydroelectric generation provides baseload power in Ontario. In contrast to nuclear generation, hydroelectric facilities are able to rapidly change their electrical output to meet energy demand needs, but their ability to do so is limited by their energy storing capabilities. Hydroelectric plants with suitably large reservoirs can store large volumes of water as potential energy that can later be transformed into electrical energy, however, large

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[7] Baseload refers to the minimum electricity demand over a 24 hour period.

[8] Grid operators in France regularly vary reactor output by large amounts to follow quick changes in electricity consumption, however, the operation of France's energy system was designed with a high level of nuclear penetration in mind while Ontario's was not. (Lokhov, 2011).

reservoirs are environmentally destructive and options for suitable sites are generally limited (Chen, 2009). Consequently, most modern hydroelectric facilities are run-of-the-river design that can only generate as much electricity as the normal river flow will allow.

For the most part, river flows are fairly predictable and are not often subject to significantly large fluctuations with the exception of medium- and long-term trends in regional precipitation, meaning that the availability of the resource used for hydroelectric generation is predictable and reliable. While hydroelectric power production can be adversely affected by drought conditions, the nature of its production and its implications on the reliability of the electricity grid have never been too large of an operational challenge in terms of incorporating large amounts of it into the generation mix. There is enough flexibility from river flow regulations that hydroelectric facilities can use an operational window[9] to help meet IESO dispatch needs. Again, the ability to provide extra power is limited by storage capabilities, but operators can curtail production via a process referred to as "spilling water" to meet sudden drops in electricity demand. In 2015, Ontario Power Generation (OPG), a crown corporation which is responsible for producing roughly half of Ontario's electricity, curtailed 3.2 TWh of hydroelectric generation, accounting for roughly 9% of the province's annual hydroelectric generation (OPG, 2016).

According to the World Bank, 66% of the world's electricity production was still generated by the burning of fossil fuels in 2014. This number shrinks to 24% in Canada and, further, to 10% in Ontario (World Bank, 2014; IESO, 2014). While this generation mix is laudable in the context of mitigating climate change, Ontario's situation does not adequately convey the challenges that the majority of countries face with respect to incorporating large amounts of renewable energy

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[9] This operational window refers to maintaining a minimum and maximum river flow.

generation. In addition to a large nuclear generation fleet, Canada is well endowed with a large amount of accessible hydroelectric energy and, although these technologies come with their own set of difficulties, solar and wind are significantly more difficult to integrate large quantities of into the energy production mix.

In contrast to conventional sources, wind and solar power plants are non-dispatchable and intermittent, i.e. they only produce power when the wind blows or when the sun shines. The inertia of electrical output from conventional sources is very predictable and controllable, however, output from wind and solar can effectively drop to zero within seconds without much warning. And while they possess similar curtailment capabilities to hydroelectric, there is no capability to increase electricity production beyond what the weather at the time will allow for. Electricity from wind and solar plants then, begin to take on a level of exogeneity which can be especially challenging to grid operators when resource availability does not correlate with electricity demand.

Electricity demand tends to be the greatest between 11am and 5pm, and in the winter and summer when households are using heat and air conditioning. With the exception of cloud cover, solar radiation is fairly predictable and tends to correlate with daily demand patterns. It also correlates with seasonal demand patterns with the exception of winter when the Northern Hemisphere receives less solar radiation. The wind, however, tends to negatively correlate with seasonal and daily demand patterns as shown in Figures 4 and 5. The reduced capability to reliably produce electricity from wind or solar when it is needed poses a problem for our current patterns of electricity consumption because it makes it difficult for grid operators to equate electricity supply with demand in real time.

Figure 4: Seasonal correlation of electricity demand and wind output for Ontario (2014)

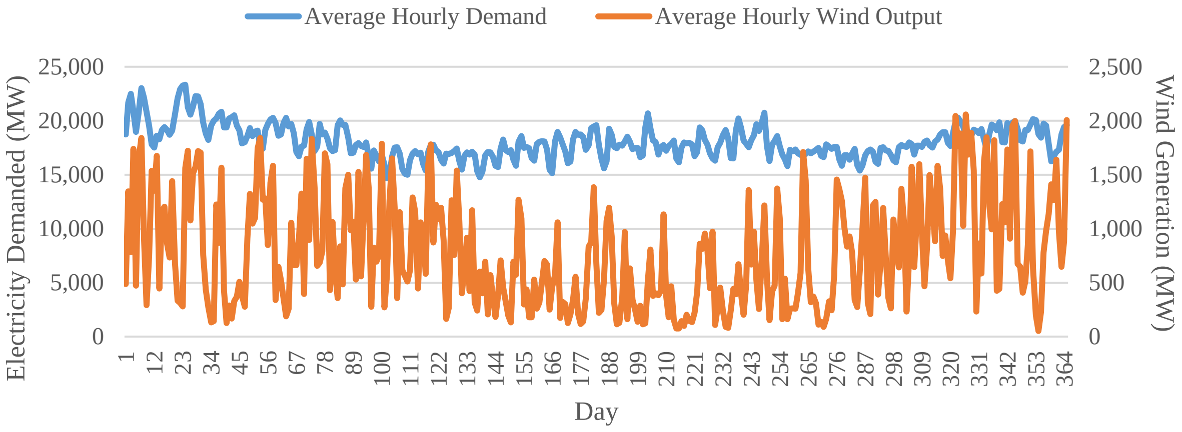
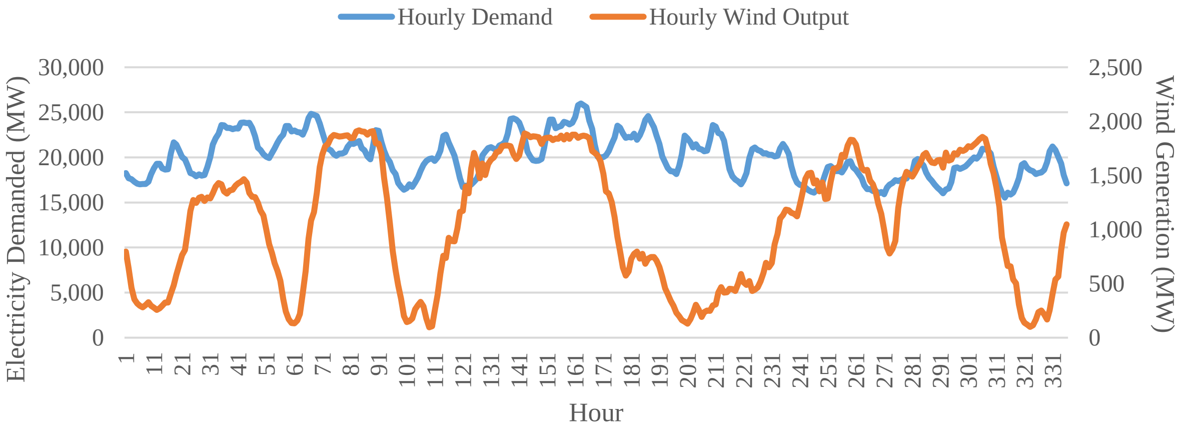


Figure 5: Daily correlation of electricity demand and wind output for Ontario (first two weeks of 2014)



There are a variety of potential options that system operators can use to manage the challenges of incorporating large levels of renewables: energy storage, geographic dispersal, and demand response are the most salient in the literature. Currently available short-term energy storage technologies such as flywheels and supercapacitors are able to smooth some of the short-term fluctuations in electrical output, however, intermittency is still a major issue when drops in electrical output are significantly large, unexpected, or last more than – depending on the technology – a few minutes or even a few seconds (Chen, 2009). The concept of energy storage is a popular one in the renewable energy literature. Evans et al. (2012) extensively reviewed 14 existing technology classifications in terms of their costs and benefits, based on 14 different parameters. Ferreira et al. (2013) conducted similar analysis and qualitatively identify the best possible applications of each existing and potential future storage technology. De Sisternes et al. (2016) assessed the value of energy storage in transitioning the electricity sector to renewables and reducing GHG emissions. The consensus, however, is that most long-term, large-scale energy storage options are simply not yet cost competitive or, in the case of pumped hydroelectric storage, there is a low availability for suitable locations.

Through careful geographic planning and optimal operation of the grid, the effects of intermittency could also be managed. MacDonald et al. (2016) found that, based on wind and solar data, the optimal dispersal and location of power plants with a suitably large (and unprecedented) transmission grid could effectively mitigate any intermittency issues suffered by the incorporation of large amounts of renewable energy sources in the United States. The chances of the wind not blowing or the sun not shining (due to cloud cover) decrease as the geographic size of the electricity grid increases. The study showed that penetration of wind and solar could reach as high as 38% and 17%, respectively, and CO2 emissions could be reduced by up to 80% relative to 1990 levels without an increase in the levelized cost of electricity. They note, however, that such a project would be at least as ambitious as the interstate highway system or transcontinental railroad. Because transitioning from fossil fuels to renewable energy is the challenge of our lifetime, it will likely require not only changes to how energy is supplied, but also to how it is consumed.

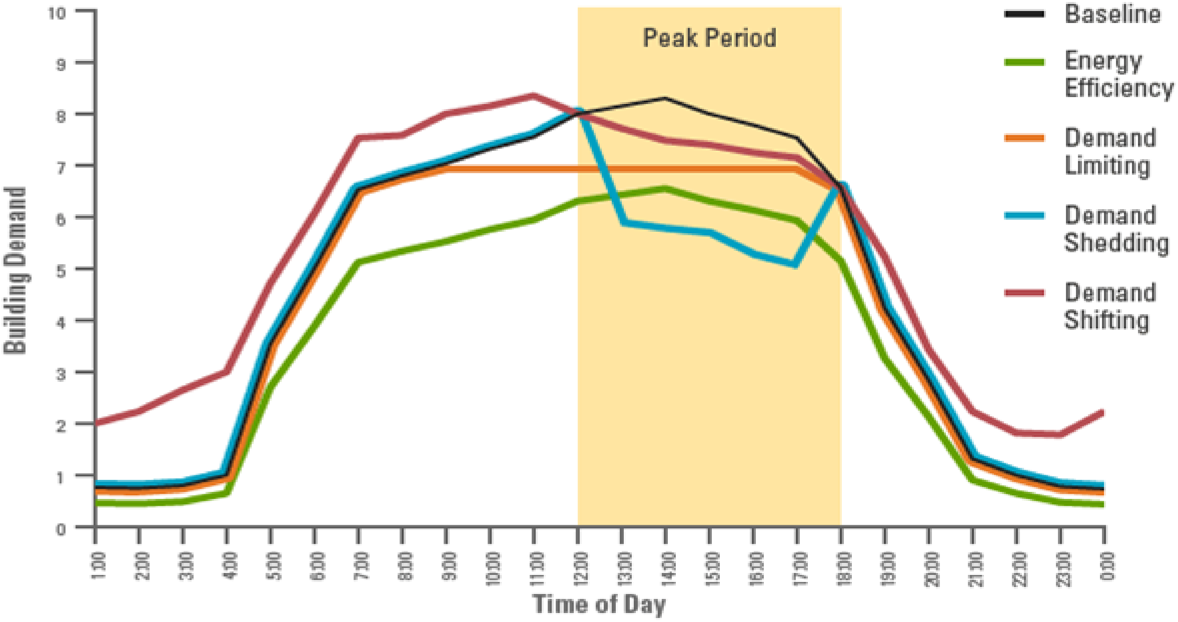
1.3 Demand Response

Historically, electricity grid operators have sought and continue to ensure that there is always electricity available to meet whatever demands might arise. As already stated, incorporating large amounts of renewable energy is in direct conflict with maintaining this reliability. While large-scale energy storage and efficient planning and operation at every juncture of the grid can theoretically achieve this, an increasingly low-hanging fruit is changing the very nature of how we consume energy. While not a new concept, the management of electricity demand has gained significant interest in recent years (Wang et al., 2015; Parvania et al., 2013; Albadi and El-Saadany, 2008). At its most basic level, demand response (DR) can be defined as "the changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time," (Albadi & El-Saadany, 2008). This also includes incentive payments designed to lower electricity usage in times of system instability and when wholesale prices are high (US Department of Energy, 2006).

There are three general classifications of response (Ibid.). First, consumers can reduce their electricity usage during peak periods of high prices without altering their consumption behaviour in other periods. This is generally referred to as curtailment or event-based response. Second, consumers can shift some of their usage from on-peak to off-peak periods. For a residential consumer, this might mean deferring the operation of the dishwasher or washing machine until later in the evening. For a commercial or industrial consumer, this could be represented by preheating or precooling a building, or rescheduling flexible business processes. Third, customers can respond by using onsite generation, such as home solar panels that are owned by the consumer (Valero et al., 2007). While this might not entail a change in consumption behaviour, from the perspective of the grid operator, demand will be decreased whenever onsite generation is used (Albadi and El-Saadany, 2008).

From the first classification, the curtailment response can be further broken down into energy efficiency, demand shedding and demand limiting. Energy efficiency refers to a permanent reduction in energy consumption, demand shedding to a temporary reduction, and demand limiting to a mandated consumption limit set out by a system operator. Figure 6 illustrates the general effects of these DR types on baseline demand over a 24-hour period.

Figure 6: Effects of various types of demand response on 24-hour electricity demand curve[10]



Depending on how each demand response is achieved by grid operators begs further clarification of the different responses, even though the same effect of reduced demand is generally achieved. There are a number of different program types in existence (US Department of Energy, 2006; Albadi and El-Saadany, 2008). Incentive-based programs include:

- *Direct Load Control programs*, where system operators have the ability to remotely shut down consumer operations on short notice. Ontario's *Peaksaver*PLUS program achieves this through a device installed near participants' central air conditioners, electric water heaters and/or pool pumps that enables the IESO to shut down the devices for four hours

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[10] Source: EnerKnol (2014)

at a time during the summer. While it may differ between electricity providers, participants generally receive a free programmable thermostat and energy tracker to help them manage electricity usage and control their bills. In 2014, the demand response was used twice, capable of delivering over 150 MW of load relief from its residential and commercial participants (IESO, 2015).

- *Curtail programs*, where consumers are given incentives or discounts to reduce their electricity usage to predefined values. In Ontario, a large variety of programs are available to help consumers become more energy efficient and reduce their total electricity consumption. Receiving rebates for energy efficient products and home retrofits falls under this category.
- *Demand Bidding*, where consumers can bid on load reductions in the wholesale electricity market. Ontario's annual Demand Response Auction is a new program that secured approximately 400 MW of DR capacity for 2016. This is for consumers of electricity, such as mills, factories and demand aggregators[11], who are capable of providing substantial reductions that can be easily managed by the IESO.
- *Capacity Market programs*, where consumers commit to providing usage reductions when called upon by system operators (usually a day in advance). Ontario's capacity-based DR program, DR-3, currently has 500 MW of capacity, however, it is a legacy program and its participants will eventually be absorbed into the previously mentioned DR Auction (IESO, 2016b).

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[11] Demand aggregators are able to bundle many small consumers together so that their response is large enough to be logistically useful to system operators. They are discussed in detail later.

- *Ancillary services market programs*, where large consumers of electricity bid on usage reductions in the spot market. When bids are accepted, participants are paid the wholesale hourly price for the entire commitment period, even if they are not required to reduce their load. The characteristic of putting consumers on stand-by makes it unique to the other programs.
- *Emergency DR*, where participants are given incentives for load reductions during emergency situations.

Many of the incentive programs penalize participants who are unable to comply with the rules of the program or meet reduction requirements, because the decision to use or save energy remains with the customer (with the exception of Direct Load Control programs).

In addition to the incentive-based programs, there are a number of price-based programs:

- *Time of Use (TOU)*, where general service customers use a three-tier pricing schedule for off-, mid-, and on-peak periods. In Ontario, there is also a monthly, usage-based legacy pricing structure that approximately one tenth of customers still use.
- *Real Time Pricing*, where consumers are charged the hourly, fluctuating price of electricity. In Ontario, this is reserved for customers using more than 250,000 kilowatt hours (kWh) of electricity per year.
- A variety of other prices that take into account critical peak periods, emergencies, and extreme periods of demand that have been forecasted in advance.

The goal of the priced-based programs is to flatten out demand by charging more expensive rates during peak periods and less expensive ones when the strain on the electricity grid is insignificant.

In addition to a variety of DR programs already in operation, the IESO is currently running a DR Pilot in an attempt to better understand the capabilities of Ontario’s DR with respect to various sources of DR and their usefulness in helping balance supply and demand. Through this pilot, the IESO has secured an additional 80 MW of DR across 20 projects from five companies (IESO, 2016c). The research on five-minute and hourly load following abilities is of particular interest to the question of how to incorporate larger amounts of renewables into the electricity production mix, because this type of DR has the ability to directly addresses the reliability gap left resulting from the intermittency of renewables.

Until somewhat recently, TOU pricing was the extent of the DR available from small-scale residential consumers. Thanks to improvements in communications technologies, i.e. the internet of things, the ability for devices to communicate simultaneously is allowing private companies, called DR aggregators, to coordinate the responses of small-scale consumers to a degree that is cost-competitive with conventional sources of generation. The introduction of these DR aggregators has allowed the capacity of DR to increase, and this capacity will continue to grow with further improvements in the relevant technologies and logistical processes. Of additional importance is the fact that aggregators effectively reduce the complexity of using DR to manage the balance of electricity demand and supply on the grid (Parvania et al., 2013).

Demand responses effectively lessen the burden on electricity providers and system operators by providing them with more control over both the amount of electricity demanded (and, thus, generation requirements) and the timing at which generation needs to occur. The ability to near-instantaneously reduce demand at a given time is at least equivalent to producing the electricity that would be needed to meet that demand otherwise. Incorporating a higher percentage of intermittent renewable energy sources into the grid means increasing the uncertainty of production. Without a complete restructuring of the electricity grid or feasible large-scale energy storage, this is not possible. However, if system operators gained more control of demand, this could help directly offset the lack of control caused by increased renewable penetration.

It should be noted, however, that there is certainly a limit to DR. There will always be a need for electricity and there are range of elasticities for various operations requiring electricity. That is, certain industrial and commercial processes need electricity at any given moment. Too much demand response would violate arguably the most fundamental characteristic of our electricity grid: that consumers can reliably access electricity when they need it.[12] If we are to introduce a certain amount of variability and uncertainty into the system via renewable energy, however, we must compensate with a decrease in the uncertainty of consumer demand patterns.

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[12] Whereas earlier, reliability was referred to the ability of system operators to meet electricity demand requirements with adequate generation, here it is meant in the context of accessibility for consumers.

2 A Linear Optimization Model of Ontario's Electricity Market

This section presents an electricity dispatch model for Ontario's electricity market. The model takes the electricity generation capacity as given, and therefore does not take into account capital costs as an investment model would. That is, the model determines how to best dispatch electricity to meet demand, and the only relevant costs are dependent on how much electricity is generated. While it is simplistic, the model is complex enough to examine the various behaviours of different generation sources and demand responses at differing levels of wind penetration. The General Algebraic Modeling System (GAMS) was used to compile and run the model, and the models of Benitez et al. (2008) and Scorah et al. (2012) were used as guidance in its creation. There are three versions of the model: one without DR (NODR), one with DR (DR1), and one with higher-capability DR (DR2).

2.1 Data

The model uses 2014 electricity generation data from wind and hydroelectric sources in Ontario. The temporal resolution for the wind data is hourly. Monthly data was used for hydroelectric generation and was subsequently transformed into hourly averages for each month to fit the model. In total, approximately 6.8TWh and 37.1TWh of electricity was produced from wind and hydroelectric sources, representing 4.3% and 23.4% of the 158.3TWh of electricity demanded, respectively. Solar generation only accounted for approximately one hundredth of 1% and was therefore excluded from the model; analyzing various levels of wind penetration is sufficient for a basic discussion on the challenges of integrating renewable energy. The data sources and parameter values used for the model are found in Table A1 of the Appendix.

2.1 Methodology

The linear mathematical programming model minimizes total variable costs subject to a number of operating constraints that are discussed shortly. The objective is to designate power generation across *N* generation types (consisting of nuclear, gas, hydroelectric and biomass), over *T* periods in order to minimize the cost of generation over the sum of every period. Hydroelectric is further broken down into generation from storage and curtailment from spillage. There are 8760 hours in a year, so *T*=8760. In each equation, exogenous parameters are denoted by lowercase letters and variables which are endogenously determined in the model are denoted by uppercase ones.

Without DR: (1)

$$Minimize\ TC_{Q_{t,i}} = \sum_{i=1}^{N}\left(\sum_{t=1}^{T}(v_i \times Q_{t,i})\right),$$

where *TC* is the total variable cost ($); v_i is the variable O&M and fuel cost for generation type *i* ($/MWh); and $Q_{t,i}$ is the electricity output (MW) delivered by generation type *i* at time *t*.

In addition to power generation, a second and third version of the model allows the electricity operator to use various forms of demand response. The third version's objective function is identical to the second's, however, the third version allows for a more powerful demand response which is explained later on. The model interprets demand response in the same fashion is does electricity output. That is, demand response can be used to meet demand, which effectively lessens the need for generation from other sources.

With DR: (2)

$$Minimize\ TC_{Q_{t,i},D_{t,j}} = \sum_{i=1}^{N}\left(\sum_{t=1}^{T}(v_i \times Q_{t,i})\right) + \sum_{j=1}^{M}\left(\sum_{t=1}^{T}(v_j \times R_{t,j})\right),$$

where v_j is the variable cost of demand response of type j; and $R_{t,j}$ is the amount of demand response used (MW) of type j at time t. In total, there are M types of demand response in the second and third versions of the model. There are three types of DR in the model (M=3).[13]

The cost function in each version of the model is minimized subject to a number of constraints that are derived from the need to satisfy energy demand in each period and various characteristics of the different types of power generation:

Market Clearance: The electricity generated must be equal to or greater than the electricity demanded in each period: (3)

$$\sum_{i=1}^{N} Q_{t,i} + w_t + h_t \geq e_t - R_{t,j}, \qquad \forall\, t\,,$$

where w_t is hourly wind power generation data (MW); h_t is hourly hydro power generation data (MW);[14] e_t is the amount of electricity demanded in each hour of 2014 (MW); and R_t is the amount of demand response used (MW).[15]

Capacity: The electricity produced by each generation type in each period should not exceed their respective generating capacities: (4)

$$Q_{t,i} \leq c_i, \qquad \forall\, t, i\,,$$

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[13] While different types of DR can be differentiated by how system operators achieve reductions in output from consumers, as it was earlier, it should be noted that the model does not do this. Consequently, generalized responses are included in the model and are only differentiated by the different capabilities assigned to them in the constraints section below.

[14] In addition to the exogenous hydro power generation data, $Q_{t,i}$ contains a small capacity for dispatchable hydro power, intended to account for hydroelectric stations with a reservoir.

[15] Note: for the NODR model, $R_{t,j}$=0.

where c_i is the is the aggregated generation capacity (MW) of generation type i. The energy output from each source is positive with the exception of hydroelectric spillage, whose output must be greater than or equal to its capacity, meaning it can only spill so much at a time.

Hydro Spillage Limit: According to OPG, 3.2TWh worth of electricity was spilled in both 2014 and 2015. While theoretically more could be spilt, this value was used to keep the model in line with previous years: (5)

$$\sum_{t=1}^{T} Q_{t,spillage} \geq -3.2TWh$$

Ramping: As discussed earlier, different types of generation can dispatch power better than others. The amount of electricity output cannot be changed instantaneously, so the following constraints are used:

Ramping up: $Q_{t,i} - Q_{t-1,i} \leq \Delta_i, \quad \forall\, i$ and (6)

Ramping down: $Q_{t,i} - Q_{t-1,i} \geq \Delta_i, \quad \forall\, i\,,$ (7)

where Δ_i is the maximum amount that output can be increased or decreased between each period for generation type *i*. These capabilities also vary between power plants of the same type and whether or not a plant is ramping up or down, however, for simplicity, they are assumed to be the same for each direction and within each generation type.

Minimum Generation: Some generation sources cannot be completely shut down, such as cogeneration gas plants that provide heat and electricity to hospitals: (8)

$$Q_{t,i} \geq m_i, \qquad \forall\, i\,,$$

where m_i is the minimum value of electricity output for generation type *i*.

Storage Depletion: For the small amount of dispatchable hydroelectric power included in the model, the available capacity is also constrained by its use each day: (9)

$$Q_{t,storage} \leq 3 \times c_{storage} - \sum_{s=1}^{24} Q_{t-s,storage} , \qquad \forall\, t ,$$

This is consistent with the Ontario Power Authority definition of hydroelectric storage (peaking) plants which states that "[t]hey can only sustain continuous generation for a few hours a day before they start running out of water and need additional inflow from upstream reservoirs," (OPA 2014).

Capacity Factors: To capture the effect of planned downtime and maintenance for each generation type, a capacity factor was used: (10)

$$\sum_{t=1}^{T} Q_{t,i} \leq f_i \times T \times c_i ,$$

where f_i is the capacity factor of generation type *i*. This was only used for nuclear, gas, and biomass because the other generation sources were already predetermined (with the exception of a small amount of variable hydroelectric).

DR Capacity: The demand reduced by each demand response type in each period should not exceed the available capacity of each type: (11)

$$R_{t,i} \leq c_j , \qquad \forall\, t, j ,$$

where c_j is the capacity of demand response (MW) of type *j*.

Event-based DR: This is similar to the conservation-based *Peaksaver*PLUS program in Ontario:

$$\sum_{t=1}^{T} R_{t,eb} \leq f_{eb} \times T \times c_{eb} ,$$

where f_j is the capacity factor of the event-based response. In Ontario, the program is clear that it can only be used up to 40 hours in the year and only during the summer months, however, the model's application of this DR is significantly more liberal in terms of its operating constraints.[16]

Daily DR: One type of demand response can be used on a daily basis. This was modeled after the IESO's contractual event-based demand response program for commercial and industrial participants: (12)

$$\sum_{t \in d} R_{t,daily} \leq c_{daily}\,, \qquad \forall\, d\,,$$

where each day, *d*, is comprised of 24 hours and the demand response in each day is less than or equal to its daily capacity. This type of demand response is the least costly to achieve, as it represents the low-hanging fruit of demand response that can be called upon in limited amounts each day.

Shift DR: The third type of DR models the possibility of shifting output from one period to the next. This response is the most expensive to achieve because of the challenges associated with changing the logistics of a variety of different commercial and industrial operations. It is constrained in the following manner:

DR1: $R_{t,shiftup} + R_{t-1,shiftdown} = 0, \qquad \forall\, t$ and (13)

DR2: $R_{t,shiftup} + R_{t-1,shiftup} + R_{t-2,shiftdown} + R_{t-3,shiftdown} = 0, \qquad \forall\, t\,,$ (14)

$R_{t,shiftup} + R_{t-1,shiftup} \leq c_{shift}\,, \qquad \forall\, t\,,$ (15)

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[16] The primary reason for this is because more complex constraints would require a different mathematical solver and more time to learn how to implement it. It was deemed sufficient that a basic response that could be used in each hour would provide suitably rich data to discuss.

where the demand response used in period *t* must be equal to the negative of the demand response used in period *t-1*. This is where the difference between DR1 and DR2 become apparent. It is important to note that all three demand responses are included in both DR1 and DR2, however, DR2 allows for a longer time horizon in which the shifted demand must be balanced. For DR2, this balancing can be done over a span of two periods instead of one. Without (15), the model would double both the time horizon and the available demand response.

Shift Equilibrium: A simple equilibrium constraint to ensure that the shift demand response only represents a shift, rather than changing the total amount of output needed from generation sources to meet demand as the event-based and daily responses do: (16)

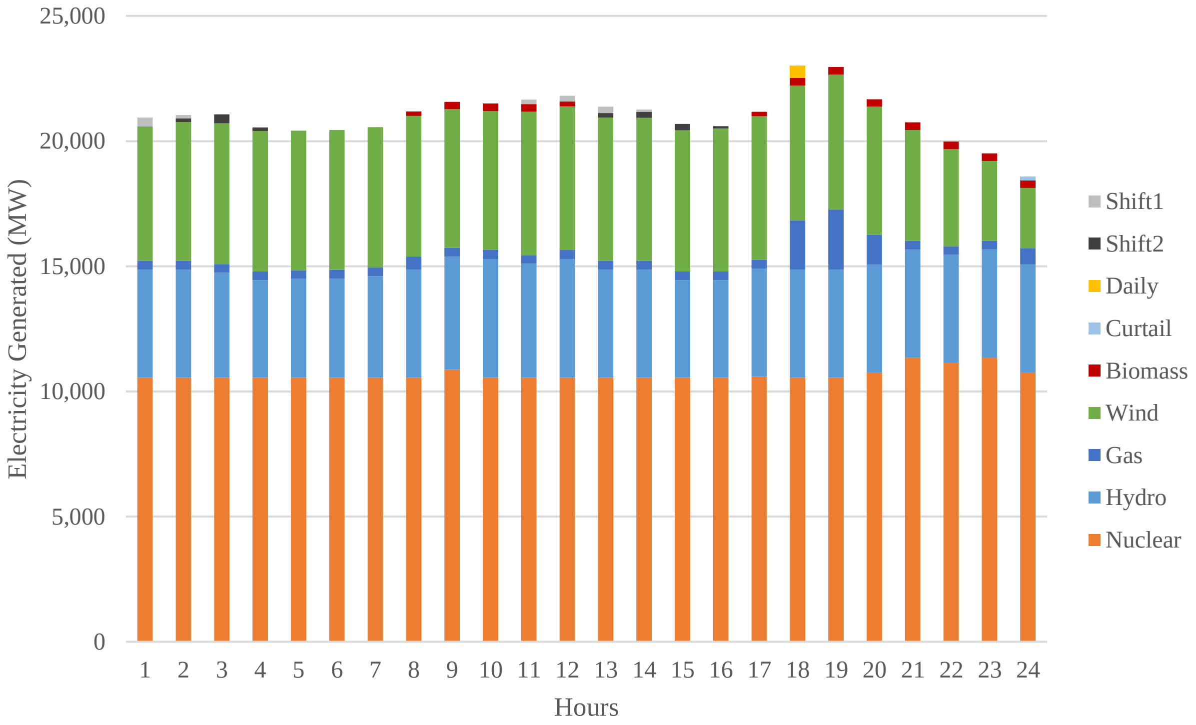
$$\sum_{t=1}^{T} R_{t,shift} = 0 \,,$$

where without this constraint, the model would take advantage of the beginning and ending periods that would otherwise allow the aggregate of all demand shifts used in the model to be non-zero.

3 Results

Each version of the model was run over five scenarios of varying wind penetration in the electricity supply mix.[17] Figure 7 presents a typical 24-hour day, highlighting the model's use of the various generation sources and demand responses. As expected, electricity from nuclear and hydroelectric generation is fairly constant. When demand is high and when there are sufficiently large hourly changes in demand that cannot otherwise be met by nuclear generation's limited ramping capabilities, the model uses progressively more expensive options which can adequately meet the generation requirements.

Figure 7: Behaviour of different generation sources and demand responses



Note: The model shifts demand from Shift1 to Shift2.
Shift1 = less demand / less generation required
Shift2 = more demand / more generation required

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[17] This was achieved by multiplying the exogenous wind data by a factor of 1–5, resulting in the percentage of electricity demand met by wind to equal 4.3%, 8.5%, 12.8%, 17.1% and 21.3%, respectively.

The model uses the different DR types to both directly replace more expensive resources as well as smooth demand fluctuations that would otherwise necessitate the use of more expensive generation sources. It also uses these demand responses to address increased electricity supply variability at higher levels of wind penetration.

Table 1: Variable cost of meeting electricity demand

Wind Penetration	Without DR	With DR	With longer DR shift horizon
	($ millions)		
4%	2510.0	2500.8	2499.4
9%	2218.1	2208.5	2206.7
13%	2020.1	2011.1	2009.4
17%	1895.1	1886.9	1885.4
21%	1807.3	1799.6	1798.1

Table 1 gives the variable cost of meeting electricity demand, including both electricity generation and DR costs. Because this model only accounts for variable costs, as wind penetration increases, the total cost imposed on the grid operator declines in all three cases. This is expected from renewable energy sources like wind and solar because of their near zero marginal costs.

The incorporation of DR into the model has a significant cost saving impact, as visualized in Figure 8. The cost of DR is less expensive than gas and biomass in the model, meaning that it will use the capacity available from these sources first. Given the constraints of DR in the model, operators are able to rapidly adjust the effective output of each demand response, making them effective at balancing the supply and demand of electricity.[18]

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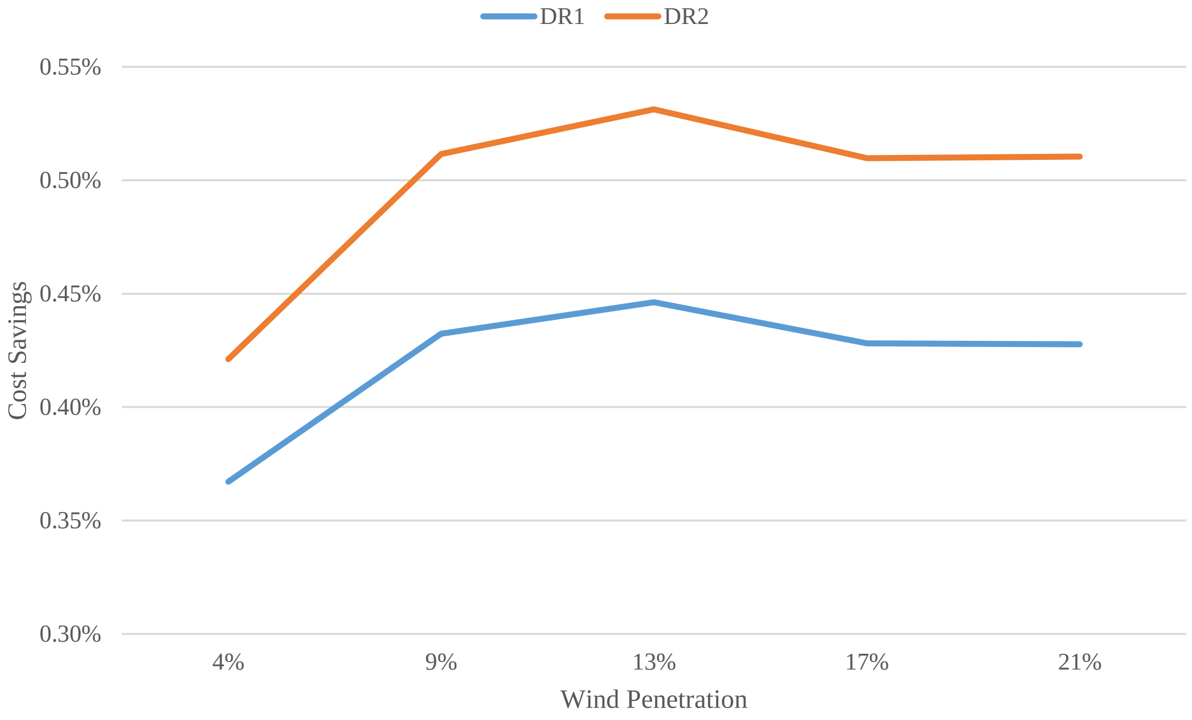
[18] That is not to say that all DR types are easier to implement than conventional peaking resources, given the technical and logistical challenges; however, these challenges are becoming less difficult with ongoing technological improvements.

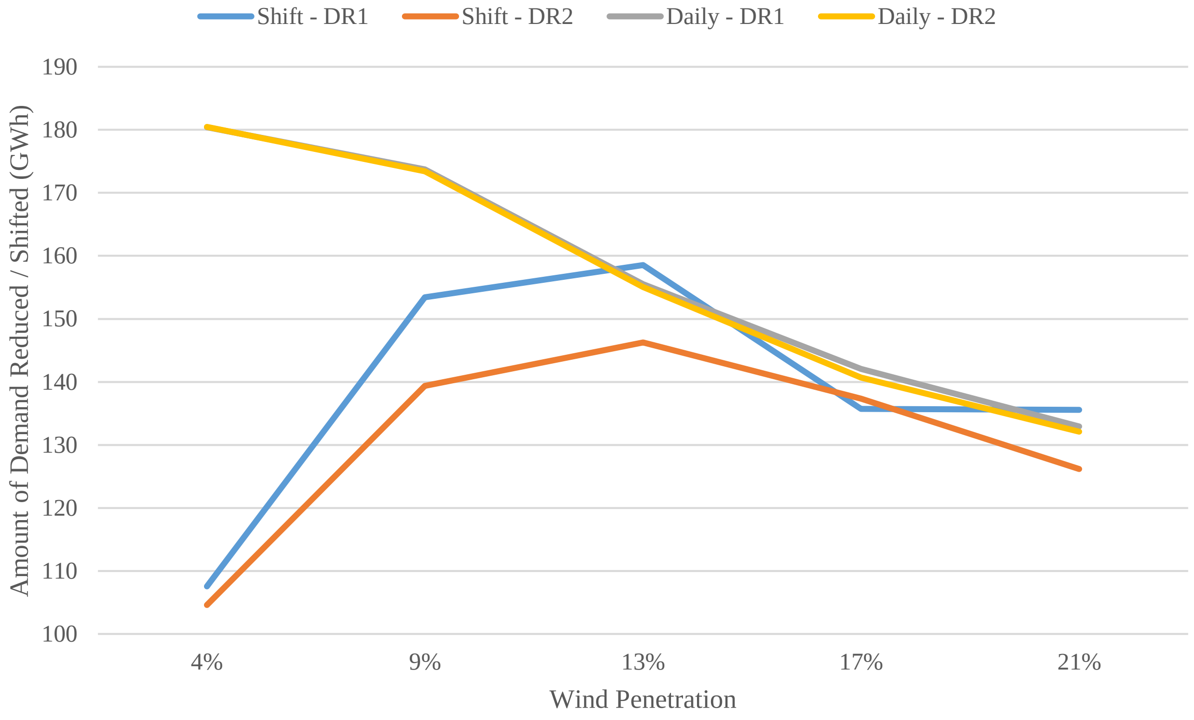
Figure 8: Cost savings as compared to the case without DR



Less of the more expensive generation sources are used in every version of the model as wind penetration increases because they are not needed, however, demand response further substitutes these expensive sources in version DR1 and DR2 of the model, leading to cost savings over the case with no DR. The cost savings increase as the level of wind penetration increases because the relative share of demand met by inexpensive DR sources increases. This only occurs until approximately 13% when the increased output from wind lessens the need for all generation sources, DR included. Another way of explaining this behaviour is as follows: As wind penetration decreases from 13%, the share of electricity demand met by DR decreases, resulting in a less significant cost savings. As wind penetration increases from 13%, less of the response is used because it is not needed to meet demand.

Figure 9 shows the model’s usage of different demand response types at varying degrees of wind penetration, confirming the relationships described above. The limited amount of event-

Figure 9: Behaviour of different demand response types



DR1 = version of model that allows some demand to be moved from one hour to another
DR2 = version of model that allows demand to be shifted and balanced over two hours

based capacity – modeled after Ontario's *peaksaver*PLUS program – is fully used in each model, so it has a negligible effect on the cost savings between different levels of wind penetration. However, the shift and daily DR types do affect the cost savings. The daily DR allows the model to reduce electricity demand by up to 500MW each day, similar to how a system operator can call upon program participants to reduce their electricity consumption at various times each day. As the level of wind penetration increases, less and less of the daily DR is needed. The shift response, however, works by lessening demand in some hours and increasing it in others. As the wind penetration increases, the shift response is used more frequently in order to help smooth the larger fluctuations in the electricity supply caused by increased wind output. That is, the increased variability of electricity supply as a result of increased wind penetration necessitates more frequent demand shifts to help balance electricity supply and demand.

Once wind penetration surpasses 13%, however, the fluctuations of electricity supply caused by hourly changes in wind output are significantly large that the amount of DR shift capacity cannot adequately account for them. Instead, the model uses more electricity from gas generation to meet these fluctuations. Increasing the shift DR window from one hour to two gives the model more flexibility, not only decreasing the amount of shift DR needed, but also output from gas generation. This leads DR2 to have larger cost savings than DR1.

This highlights the important distinction between the different types of demand response. While the event-based and daily responses effectively achieve the same effect of conventional generation,[19] the response of the demand shift is fundamentally different. For both DR cases, it is used when there are large differences in energy demand between hours, or when the exogeneity imposed by increased wind output leads to larger differences of electricity supply between hours. By shifting demand, the energy operator can adequately lessen these differences between hours to a point where a low-capacity ramping resource, such as hydroelectric generation, can meet these differences in demand where they could otherwise not be able to in the absence of the demand shift response.[20] The ability to shift demand over two periods instead of one adds significant value to this function.

Figure 10 looks at the standard deviation of hourly changes in output from gas generation divided by total output from gas generation across all periods. In effect, this metric measures the

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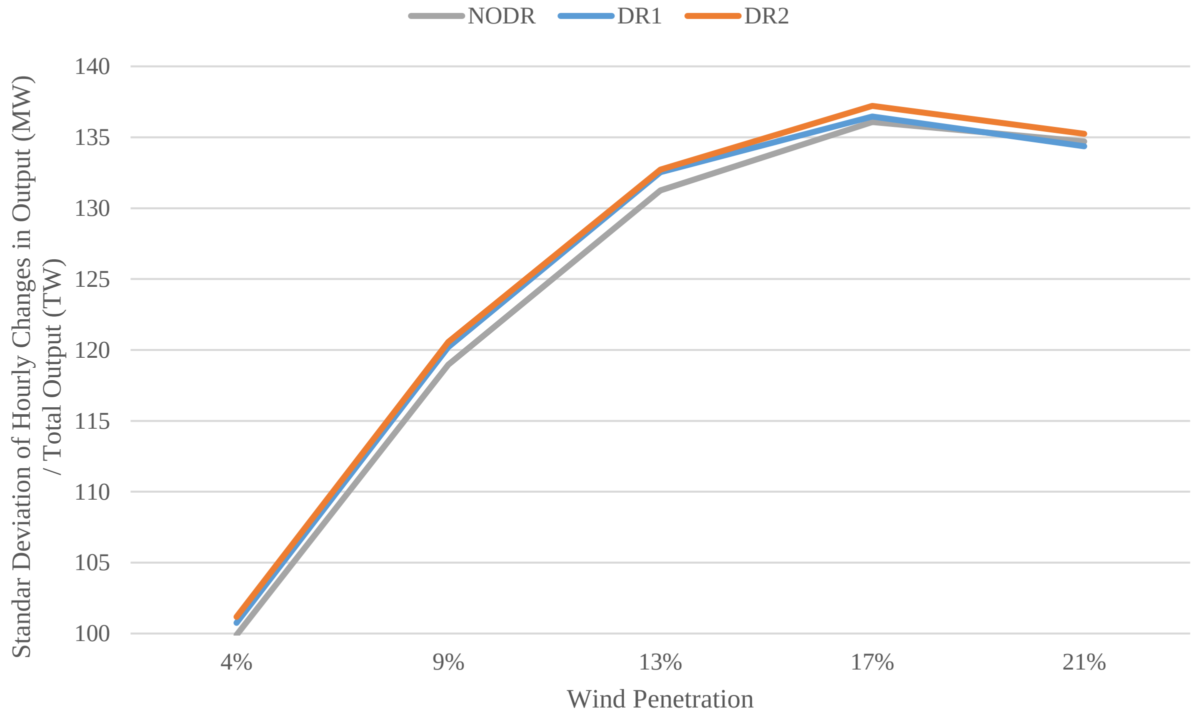
[19] The event-based response is the equivalent of a cheaper, more responsive peaking power plant with significantly less capacity and the daily response is similar to the depletable hydroelectric storage with a small capacity that can be drained over a period of time.

[20] The model seeks to minimize total costs, so if the demand shift response allows a lower cost generation source to be used, the model will prioritize it.

average size of changes in hourly gas output relative to its total output. This gives an idea of how much of the gas generation behaviour is devoted to ramping and following the hourly load changes. The relative size of hourly output changes increases for all versions of the model as wind penetration increases. As such, gas generation is kept at the minimum amount more often. This results in changes in hourly gas generation that are both larger and more heavily weighted at higher wind penetration levels.

Figure 10: Relative Size of Hourly Ramping by Gas Generation Sources

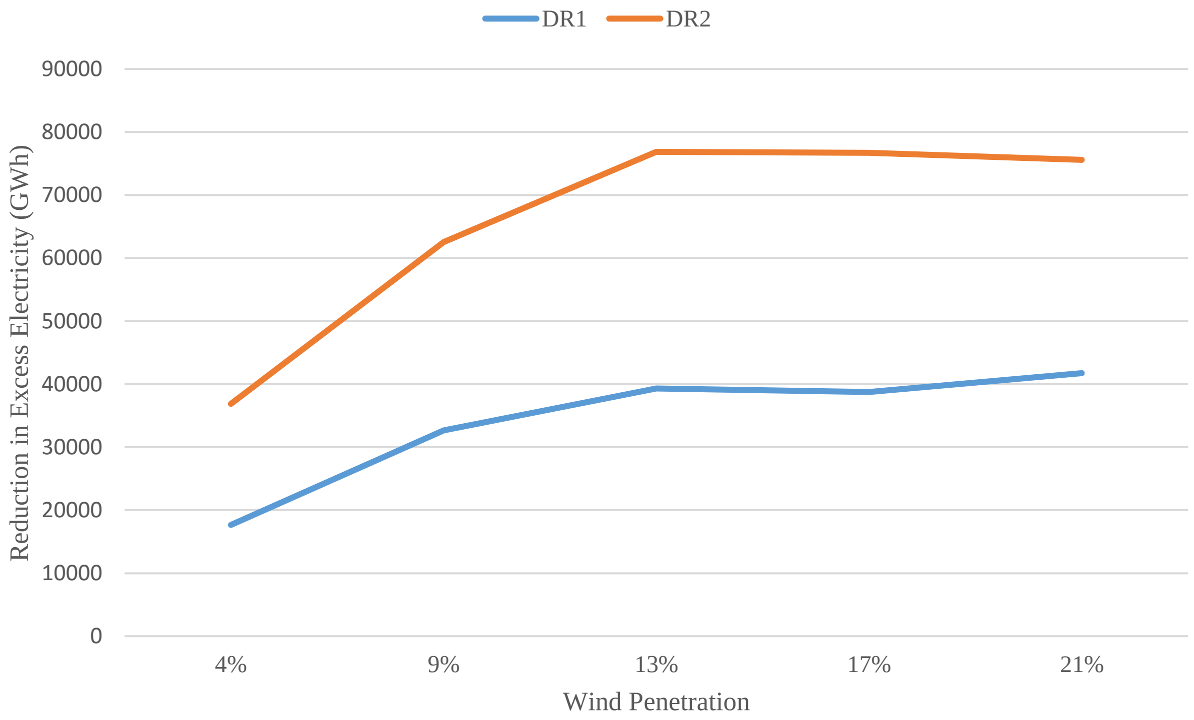


Compared to NODR, the versions of the model with DR both increase the average size of hourly changes in gas generation. This is because DR can be used to balance out the smaller differences between electricity supply and demand, leaving gas generation to manage only the larger differences. The slight difference between DR1 and DR2 achieves this to a greater effect: the ability to shift demand over a longer time horizon in DR2 further increases the average size of hourly changes in gas generation compared to DR1, especially at higher levels of wind penetration.

With increasing wind penetration, it is obvious that the decreased flexibility in the generation mix means that other generation sources need to be more flexible. Although its capacity is limited, demand response achieves this flexibility, and at a lower cost than gas generation.

Figure 11 shows the reduction in excess output as a result of introducing DR into the model, compared to the case without DR. Although no cost was assigned to excess electricity generation in the model, in reality, it can be quite expensive for grid operators to deal with. In June of 2015, for example, Ontario paid $221 million to produce and export 1.9TWh of surplus electricity (Blizzard, 2015). This works out to roughly $116/MWh – nearly twice as expensive as the cost assumed for gas generation in the model. It is a very real challenge ensuring that there is never more electricity on the grid than it can handle, both for technical and economic reasons.

Figure 11: Reduction in excess electricity as compared to the case without DR



At all levels of wind penetration, there is a reduction in excess output. The larger reduction in excess output from the longer shift horizon is substantial and if we factor in a price of excess electricity in to the results of the model comparable to the example above, the cost-savings from demand response is even more pronounced. At higher levels of wind penetration this reduction flattens out, largely due to the construction of the model. This will be discussed in more detail in the limitations section.

4 Discussion

While the results contained much of the discussion, this section serves to summarize them and discuss some of their implications for Ontario's electricity market.

First, as wind penetration levels go up, the efficacy of conventional operating procedures and resources decreases. That is, the increased variability of wind generation restricts the usefulness of other resources to respond to demand fluctuations – more time is spent smoothing out fluctuations in supply instead. Larger discrepancies between demand and supply mean that potentially cheaper low-ramping capability resources are not relied upon as much as they could be in an environment of lower wind penetration.

Additionally, the amount of excess electricity generation increases as the level of wind penetration increases. The cost savings from varying degrees of demand response are apparent in the model, and the reduction in excess output and electricity generation smoothing behaviour are a testament to its usefulness. The daily and event-based responses effectively both substitute out gas and biomass generation when the hourly changes are small enough for their capacities to cover the difference in supply and demand, and smooth demand fluctuations to make up for a more variable electricity supply.

Already in Ontario, there is much activity taking place surrounding the development and evolution of DR. Iterations of IESO programs, namely CBDR (Capacity Based Demand Response), have evolved and given way to more effective ones such as the annual DR auction. These programs are likely to continue growing with DR aggregators' ability to provide increasing amounts of DR capacity. The technological advancements in communications technology are helping aggregators open up previously inaccessible DR resources.

The IESO, along with electricity system operators around the world are exploring the ever-expanding toolkit of DR. However, if we intend to take action against climate change, stakeholders in the electricity market decision-making sphere must continue to involve regular consumers of electricity in the DR process as their ability to do so increases. At the time of writing this paper, Ontario's *Peaksaver*PLUS program is no longer accepting new participants. It is unclear from the latest impact evaluation of the program whether this is due to a shortfall of funding, capacity limitations, or whether it stems from a concern that if the program expands too quickly, it may be unviable in its current configuration at scale (IESO, 2015).

The results of the model are clear, however, that demand response provides an opportunity for grid operators to incorporate an increasing penetration of renewables by making it less expensive to operate the grid. By doing so, they can effectively mitigate the negative impact of introducing intermittent renewable resources into the supply mix through a higher degree of control over electricity demand. This is especially clear for a high-capability demand shift response.

5 Limitations and Future Research

While it is fairly easy to look at the results from the model and get a sense of how demand response affects the balancing of electricity supply and demand, it is important to note that there a number of limitations in the model. The choices made in the construction of the model, the lack of a spatial dimension for electricity transmission, exclusion of electricity imports and exports, and simplicity of electricity generation and demand response behaviour all make the results from this model largely qualitative.

Firstly, the model was constructed to be simple. In terms of balancing supply and demand, for example, the model only needs to ensure that the electricity supplied in each period is always greater than what is demanded. While the price of excess electricity could have been directly included in the model to penalize excess electricity production, it would not make sense to do so. Including it would arbitrarily increase the cost of the model as wind penetration increased. In reality, the electrical output from wind sources could then be curtailed to reduce this excess electricity, but if wind curtailment was included in the model, it would be difficult to achieve a high penetration of wind – the model would always curtail wind when it needed to. While this could potentially answer other questions regarding the maximum viable wind penetration level, it would not let us examine the problems of dealing with increased exogeneity in the electricity supply as the current model does. All this is to say that there were tradeoffs and associated costs when constructing the model.

The importance of the spatial component of electricity supply management cannot be understated. Electricity does not costlessly travel from the point of generation to the point of consumption. Not only is the amount of electricity traveling through any given transmission line limited, but it loses power as it travels greater distances. The model does not adjust the cost of electricity generation from more remote sources to reflect this reality. A model addressing this issue would effectively assign a rough geographic location for generation and consumption, and constrain the transmission of electricity based on the distance and rated capacity of the transmission lines between generation sources and points of consumption.

Including the imports and exports of electricity would also increase the accuracy of the model. The challenge with this would be finding the appropriate wholesale prices as well as the electricity supply and demand schedules of neighbouring grids. The efficient coordination of electricity imports and exports to nearby grids will play an increasingly important role in the incorporation of more intermittent renewables into the grid. As suggested by MacDonald et al. (2016), the greater the area in which renewable power sources are situated, the more efficiently grid operators can deal with the increased uncertainty of supply offered by an increased penetration of renewable power sources, so long as the electricity can be transmitted across larger distances. Of course, this is limited by the transmission infrastructure itself, but the more imports and exports of electricity travelling between two separately controlled grids, the more the two grids act as a combined, larger, and more efficient grid. Additionally, excess electricity generation can be mitigated somewhat through exports, even if the price at which it is exported is lower than the cost of producing it.

More sophisticated constraints for both electricity generation and demand response would yield more reliable results. In Ontario for example, although the Bruce Power nuclear units offer 300MW of ramping capability each,[21] in practice, nuclear energy output from hour to hour stays

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[21] The Bruce Power Generating Station houses eight generating units for a combined total of 2400MW of ramping capabilities.

relatively stable. And while the model contained basic assumptions about the ramping abilities of gas, biomass, hydro, and DR equally, in reality, the ramping rates of generation sources are dependent on their current output. Ramping up from a cold start objectively takes longer for fossil fuel plants than an adjustment when the plant is already running. It should be noted that this simplicity still allowed for a basic qualitative comparison between the ramping behaviours of different generation.

Lastly, the inclusion of a demand response that modeled consumer choices based on the price of electricity consumption would also further explain the aggregate effect on the electricity market, however, this was beyond the scope of the paper in terms of what could be achieved with the linear model used. Additionally, assigning different demand response capacities for different times of the day would better model the real world.

Future research could take these limitations into account and build a more sophisticated model that would achieve more objective results. Further, modelling an electricity market such as Alberta, where there is ample room for the displacement of coal power generation with renewable sources might be more relevant in the context of increasing renewable penetration. Additionally, a more in-depth look at the demand response capabilities of a given electricity market would be fruitful in conjunction with a similar mathematical model.

6 Conclusion

Climate change is the greatest challenge that humanity has ever faced. Never before has the habitability of our planet been in question to the extent it is today. There is a scientific consensus that the world needs to transition from fossil fuels to renewable energy. From generation to transmission to consumption, the energy system is arguably the most complex machine ever built by humans. Incorporating intermittent renewable energy sources drastically changes how important aspects of this machine operate and it will require that, in the absence of cost-effective long-term energy storage, we modify the way we use it. This paper linearly modeled Ontario's electricity market for 2014 to explore the behaviour of various demand responses in the electricity market as well as its relationships with various types of power generation. Though it is not sufficient, it is ultimately necessary that demand response play a vital role in facilitating the aforementioned transition.

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Appendix

Table A1: Data Summary

Parameter	**Value / Comments**
Demand data[a]	Ontario for year 2014
Wind data[a]	Ontario for year 2014
Hydro data[a]	Monthly output for year 2014 transformed into hourly output
O&M variable costs including fuel[b]	Nuclear: \$12.2/MWh Gas: \$59.1/MWh Variable Hydro: \$7/MWh Biomass: \$37.6/MWh Wind: \$0
Generation capacity[c]	Nuclear: 12,947 MW Gas: 9,920 MW Variable Hydro: 5% of 8,485 MW = 424.25 MW Biomass: 302 MW
Demand response costs[d]	Curtailment: \$20/MWh Daily: \$15/MWh Shifting: \$25/MWh The three DRs included in the model resemble the conservation (*peaksaver*PLUS), event-based (DR-3), and load shifting (DR-2) programs of the IESO, respectively, and are priced according to the reported costs of these programs in past years.
Demand response capacity[e]	Daily and Shifting: 500 MW Curtailment: 150MW The IESO programs used in Ontario are not dissimilar to this number.
Ramping constraints. Maximum change in output between any hour	Nuclear: 600MW (30 min for each manoeuver of max 300 MW) Hydro and Gas: 100% of capacity Biomass: 60% of capacity
Capacity factor	Nuclear: 82% Gas: 50% Biomass: 50% Curtailment DR: For nuclear, it is equal to the lifetime capacity factor of CANDU reactors.[f] Gas and biomass factors were derived by looking at previous years of performance.[c]

[a] From IESO website: http://www.ieso.ca/Pages/Power-Data/default.aspx#download

[b] U.S. Energy Information Administration. (June 2015). Levelized cost and Levelized avoided cost of new generation resources in the annual energy outlook 2015.

[c] From IESO website: http://www.ieso.ca/Pages/Power-Data/Supply.aspx

[d] From IESO website: http://www.powerauthority.on.ca/about-us/electricity-pricing-ontario/opa-generation-and-conservation-resource-costs/resources-peaking

[e] From IESO websites: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2016.xml , http://www.ieso.ca/Pages/Participate/Capacity-Based-Demand-Response.aspx , http://www.powerauthority.on.ca/sites/default/files/conservation/2014-Evaluation-peaksaverPLUS.pdf

[f] Canadian Nuclear Society. (2015). Nuclear Canada yearbook 2015: Annual industry review & buyers guide.