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Project DEMOCRASI

Product adaption opportunity assessment report

Power Forward Challenge 2020

Milestone: 1

Document: 1.1

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Date: 13 July 2020

Document validation criteria: An outline of how the technology collaboration between Kiwi and Opus One can be applied to the Canadian market specifically Ontario and Alberta in relation to demand response or other markets participation using aggregated distributed energy resources.

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Document conventions

Throughout this document you will find coloured boxes that represent.

Orange boxes represent areas which update will be included in upcoming deliverables. They require the selection of an alternative secondary market for simulation as a result of ATCO, a former utility partner, pulling out of the project. Once a market has been selected, this must be agreed with Natural Resources Canada (NRCan). Exploration of suitable markets will form part of Milestone 3 (M3). For this reason, the content will be completed for M3.

Grey boxes represent commentary, observations and recommendations from the project participants. Where appropriate they make a comparison with the UK markets.

1 Introduction

This report is a vital first step for the project participants as we advance towards the goals set out for DEMOCRASI. To be able to prepare effectively for the interaction between distributed energy resources, distribution and transmission networks in Ontario and beyond, it is important for us to understand how those three key parts of Ontario's electricity system are regulated and viewed politically, as well as the competitive markets currently in operation across these areas in Ontario and other markets.

The report highlights energy policy and regulatory issues at a Federal level in Canada, although there is very limited national political impact on energy matters with nearly all decision-making resting with each Province. The report also covers equivalent arrangements in Alberta, which along with Ontario is a focus of the DEMOCRASI project.

We then delve more deeply, examining the existing Ontario and Alberta markets and exploring future market developments. This will serve as a common knowledge base for project partners to ensure that we all have a strong understanding of the market(s) which will be the focus for project delivery, and the economic, regulatory and policy rationale which underpins market participation.

To enable us to decide which markets to participate in during the project period we take a look at the technology solutions and systems offered by the project participants and the flexible resources that are available for participation. We use this document to record and communicate our market selection and discuss the impacts this decision will have on the project.

Throughout the report we bear in mind that our understanding and our solution must be applicable for deployment beyond Ontario and Alberta. Where applicable, we make comparisons with markets outside of Canada, in particular with the UK.

This report prepares the foundation for future scenario studies, scalability strategies and the final project report.

2 Policy & Regulation

2.1 Federal energy policy in Canada

At a Federal level in Canada there are relatively few areas where policy and regulation in the energy sector takes place. This is because under the Canadian constitutional arrangements each province sets energy policy and regulation as appropriate for their respective geography. The national Government is able get involved in energy policy and regulation in a few distinct areas, being anti-trust issues within the sector, any relevant cross-border energy issues between provinces, and on carbon pricing.

Recently, the Canadian Government's attempts to introduce carbon pricing into the energy markets across Canada has been the highest profile and most controversial example of a policy intervention at the Federal level. However, as carbon pricing is a Federal rather than Provincial initiative, there are no guarantees that it will be implemented or followed by the provinces, which is likely to result in a legal process to determine whether the Federal or Provincial approach takes precedence in this area.

The direction of policy and regulation in any jurisdiction is likely to be affected by a range of factors, many of which are common. For example, the political persuasion of the Government of the day is clearly a strong factor which will influence the manner in which policy and legislation will develop in a jurisdiction. In turn, this may be affected by previous successes or failures as, for example, a previous failure of energy policy or regulation is likely to result in a cautious approach in future. Similarly, the abundance of natural resources in a jurisdiction may also guide the Government's actions due to the necessity for employment in the resources sector, or the cost-effectiveness of harnessing those resources for use in electricity production.

2.2 Energy policy in Ontario

The provincial Government in Ontario has responsibility for the overwhelming majority of energy policy and regulatory decision making in Ontario. The current Ontario Government is composed of members of the Progressive Conservative Party of Ontario, whose term is due to run until June 2022.

The Ontario PC Party's platform ahead of the election contained key commitments relating to the energy sector. They campaigned on the basis that the costs of electricity were too high and spiralling out of control due to historic contracts entered into by Hydro One. Following the 2018 election, several new initiatives have been enacted to try to reduce electricity costs in Ontario.

2.3 Ontario provincial energy regulation

Energy regulation in Ontario dates back to 1998 with the passage of key legislative Acts which set the tone for much of energy regulation in the province historically and to this day. The Ontario Energy Board Act (OEBA) 1998 created the licencing regime operated by the Ontario Energy Board (OEB). Market participants which are required to obtain a licence from the OEB are generators, transmitters, distributors, and retailers.

The license requirements involve the registered party complying with a range of regulatory codes set out and maintained by the OEB (e.g. distribution system code, transmission system code, retail settlement code, affiliate relationships code). These contain very detailed forms of regulation beyond the level of specificity possible via legislation

Regulation also takes place via environmental means, e.g. via the Ministry of Environment and Climate Change (MOECC) for things like generation emissions intensity etc.

2.3.1 Grid connections

The second key piece of 1998 legislation, the Ontario Electricity Act (OEA) 1998, obligates transmission and distribution owners to connect new generators. As part of the connections process, the Independent Electricity System Operator (IESO) has a role in overseeing the connections process for sites >10 MW, by conducting a system impact assessment (SIA) to assess various aspects around the suitability and expected impact that the new connection will have on the system. Most connection agreements will take a standard form. Currently, Ontario regulations state that for a generator to connect to the system, they are liable for the full set of costs associated with the connection, whereas load customers cover marginal additional costs over a specified time period agreed as part of the connection offer.

2.3.2 Alternative energy sources (renewables)

The Green Energy Act (GEA) 2009 introduced the Feed in Tariff scheme, which enabled renewable generators to earn a 20-year guaranteed price contract with Ontario Power Authority via RFP procurement process. According to the current Ontario Government, this scheme is largely responsible for the escalating and high electricity costs faced by bill payers in Ontario. In addition to the renewable capacity connected resulting from the GEA, Ontario has shuttered all of its coal plants, as part of a process starting in 2003. There is no current appetite for new coal plants to be constructed in the province.

2.3.3 Climate change policy

There is of course a large co-dependency between energy and climate change policy in Ontario, as in all other jurisdictions. In Ontario, the Climate Change Act 2016 created a localised cap and trade type system for carbon credits. The Ontario Government also published a 5 year climate change action plan in 2016, which is due to be evaluated over the coming months.

2.3.4 Transmission regulation

Under Ontario's regulatory regime, the boundary between the transmission and distribution networks is set at +/- 50kV. Voltage levels above 50kV are therefore classified as transmission, with those below 50kV categorised as distribution. OEB is responsible for issuing the relevant licence for transmission networks, most of which are issued to Hydro One who own over 90% of all the Ontario transmission system. Environmental impact assessments are required to be produced when new transmission lines are proposed, but the stringency of the impact assessment depends on the planned length of the line and the kV rating of the cable. However, there remains an element of political control over the transmission system, as the Ontario Cabinet has the power to declare that a new or upgraded transmission line is a 'priority' project to be completed, e.g. to serve a poorly connected community. These projects do still require OEB approval to take place. There has also been some limited efforts to open up transmission line construction to competitive processes, but the most notable example of an OEB-run tender was the 2011 construction of a 400km transmission line, with limited evidence that further competitive tenders are due to take place imminently. This may need to be revisited in light of non-network solutions becoming viable at the transmission level.

Grid Reliability in Ontario is measured by the performance against NERC (North American Electric Reliability Corporation) standards, and is done by the OEB. Criteria from the NPCC (Northeast Power Coordinating Council) are also used in assessing grid reliability.

As referenced above, distribution lines are classified as being <50kV. The process for constructing distribution lines is less onerous from a regulatory perspective, with limited environmental assessments required and no requirement for OEB approval. The added layer of regulation at distribution level concerns connections and network access. Section 26 of the Electricity Act ensures non-discriminatory access for connecting parties. The connections regime operates on the basis that existing connected parties should not have to bear the cost of new connections, given distribution line expansion is done on the basis of economic rationale alone without the possibility for political intervention.

The charges for distribution network operation are regulated by the OEB, under its duties to do so contained in the OEB Act 1998. The process followed to determine the appropriate level at which it is economically appropriate to set the distribution network charges involves each Local Distribution Company (LDC) filing their methodology with OEB, and subsequently gaining approval to enact their proposed charges for their customers.

The last area of the Ontario energy market concerns power sales. Again, this area is regulated by the OEB, which issues licences to enable businesses to participate in the market. The requirements that OEB will place in a power sales licence will vary depending on whether the customers being served are larger or smaller volume customers, as they have different needs, and more stringent requirements are in place for smaller customers as a default position. It is worth noting that a distribution licence permits the LDC licensees to sell to retail customers by default, although an electric retailer licence is also available which enables the licence holder to sell energy to both large and small volume customers. Due to the default ability of LDCs to also act as a retailer, they dominate the retail market (in their local areas) in Ontario, and relatively few customers are served by an independent retailer.

2.3.5 March 2019 Government Reform Package

In March 2019 the current Ontario provincial Government embarked upon their reform package for the electricity sector following their 2018 election victory. The package reformed several administrative areas of OEB in terms of how it operates and performs its functions. A second key area of reform is in how conservation and demand management (CDM) programmes are operated. Historically, LDCs undertook a range of activities which were not planned in a coordinated manner, which the Ontario Government viewed as being inefficient and costing Ontario residents more than it should to undertake such activities. The reform package estimated this cost at $442m, and obligated the IESO to set out a plan to enact its new CDM responsibilities in 2019 and 2020.

2.3.6 Long Term Energy Plan and Market Renewal 2017

Long Term Energy plans were periodically published by the Government of Ontario to set out its planning for the future of the energy sector. The most recent Plan was published under the previous Ontario Government in 2017.

The 2017 Long Term Energy Plan contained the following key aims:

1. Ensuring Affordable and Accessible Energy
2. Ensuring a Flexible Energy System
3. Innovating to Meet the Future
4. Improving Value and Performance for Consumers
5. Strengthening our Commitment to Energy Conservation and Efficiency
6. Responding to the Challenge of Climate Change
7. Supporting First Nation and Métis Capacity and Leadership
8. Supporting Regional Solutions and Infrastructure

Market Renewal is a key means to deliver the ambition set out under point 2, 'Ensuring a Flexible Energy System'

The Independent Electricity System Operator (IESO) began a Market Renewal initiative in 2017 to redesign the province's electricity markets. This programme is expected to save up to $5.2 billion between 2021 and 2030 and forms a key component of the Ontario Government's plan to bring down the cost of electricity.

The general features of Market Renewal fall into three workstreams:

1. Energy: Move to a single-schedule market, including locational marginal pricing for suppliers, improved generation commitment and dispatch in real time, and a financially binding day-ahead market.
2. Operability: Increase system flexibility and improve utilization of interconnection with neighbouring systems to reduce costs, variable renewable generation uncertainty, and the need to curtail resources.
3. Capacity: Improve procurement of resources to meet the province's resource adequacy needs through an incremental capacity auction that stimulates competition from all qualified supply resources in a technology-neutral manner. These reforms

would increase the extent to which Ontario relies on transparent, market-based mechanisms to reliably supply electricity to customers.

One of the key aims of Market Renewal is to ensure that a wide range of resources will be able to provide flexibility, reliability and ancillary services. This will help provide revenue streams for services required by IESO with the aim of ensuring that all resources can compete on a level playing field.

Market Renewal is expected to result in a more competitive marketplace that more flexibly and efficiently meets system needs and provincial policy and regulatory goals. The Market Renewal programme is aligned with the objectives of Ontario's Climate Change Action Plan, and will be designed to meet system needs, reduce overall costs and reduce carbon emissions.

Market Renewal is aiming to assist Ontario in its preparation for the future by creating a competitive framework that cost-effectively incorporates clean energy resources and new and emerging clean technologies. The IESO, together with its sector partners, has identified the need to ensure that this new framework can properly value environmental attributes and the benefits they provide to the system. At the same time, existing resources will be able to continue to meet system needs in the redesigned electricity markets.

A reformed electricity market should not only help reduce costs, but also has the potential to increase electricity trade with interconnected adjacent markets. This could allow more imports of lower-cost generation, and provide greater revenue and access to export markets for Ontario generators.

2.3.7 Ontario at a Glance

Installed capacity	37,555 MW
Record Summer Peak	27,005 MW (01 Aug 2006)
Record Winter Peak	24,979 MW (20 Dec 2004)
Customers	5 million
Ontario Import Capacity	5,200 MW
Transmission Lines	30,000 km (18,600 miles)
Interconnections	New York, Quebec, Manitoba, Michigan, Minnesota

Transaction Value/yr	$18B
Energy Efficiency Savings	0.93 TWh

2.3.8 Distributed Generation

There is currently more than 3.4 GW of generation capacity within Ontario's local distribution systems. The largest percentage of distributed generation, also known as embedded generation, is from solar facilities.

Now that Ontario is experiencing a strong supply situation, the IESO is working with industry stakeholders to introduce changes to Ontario's energy markets that will allow for market-based opportunities for investment and participation through capacity auctions. Capacity auctions offer greater flexibility to address changing system needs in shorter time frames – three and five year periods – and at the lowest cost to consumers.

2.4 Energy policy in Alberta

The province of Alberta contains a large reserve of natural resources, and historically it has been a centre in Canada for oil and gas production. Accordingly, the production of electricity in Alberta has been dominated by traditional centralised fossil fuel plants, a situation which persists to date, given the low cost of input fuels and their local abundance.

In 2016, the Provincial Government of Alberta announced its endorsement for a recommendation made by the Alberta Electric System Operator (AESO) to move Alberta from operating an energy-only market, to operating markets for both energy and capacity. This was proposed to take place in 2021. Following the most recent set of Provincial elections, this move was reviewed by the new Government. After a period of consultation about the proposed market move, the Government decided to cancel the planned transition and revert to an energy-only market for Alberta. The legislation to approve this reversion received Royal Assent in October 2019.

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

2.5 Energy regulation in Alberta

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

2.6 Project participant commentary

Canadian policy and regulation comparison with the EU and UK

In Canada, energy policy and the regulation of the electricity system is principally carried out at the Provincial level, with only a limited number of activities being undertaken at the Federal level. Federal policy related to energy/electricity is predominantly in the area of climate change and emissions mitigation, as they are responsible for Canada's overall climate change strategy and commitments. Clearly, policy relating to climate change may affect or curb certain aspects of the electricity sector, most likely generation, thereby impacting on the ability of a Provincial Government to enact its desired plans.

In the European Union (EU), the situation is different. The European Commission has quite a wide-ranging role in relation to energy, electricity and climate change, and has enacted several legislative packages in recent years which profoundly affect the operation of the electricity system in each Member State, including in the UK. For example, EU legislation mandates that electricity systems should be 'unbundled', meaning that generation, transmission, distribution and retail may not be carried out by the same entity. This is to promote competition in each of these areas of the value chain. Conversely, no such diktat is in place in Canada, with utilities typically operating across several of these areas. Further, the EU has mandated a range of standards that transmission networks operators must adhere to in terms of when and how they procure ancillary services, and the EU's competition agency must approve a Capacity Market in any Member State prior to its inception, due to EU guidelines on State Aid. Once the UK leaves the UK, the terms of the future relationship with the EU on energy and electricity are still unknown. However, whilst the terms of the EU's planned energy and climate change legislation, things are unlikely to diverge in the short-medium term as the policy priorities of the current Government are aligned with those of the EU Commission.

In Ontario, the market reform programme is making changes to the electricity system in a more European style, through opening up more markets and enabling greater competition to provide services to IESO. This will remove barriers to entry and increase distributed energy resource (DER) participation in the electricity system, providing longer term certainty for investment in DER assets.

3 Market Frameworks and Participation

In this section we dive a bit more deeply into the competitive markets currently in operation in Ontario and Alberta. We focus only on the markets that might be accessible to distributed energy resources and the DEMOCRASI project specifically. We look at the history of those markets, how companies and facilities participate, the eligibility criteria, and where numbers are accessible, we measure the opportunity for each market. Given one of our primary project objectives is to prove our solution is also suitable for other electricity markets we also compare the Canadian markets to their closest UK equivalent.

A fundamental decision for the project consortium is the markets we choose to participate in during the project period. Whilst not the sole factor, this analysis will be of considerable influence to that decision, which we cover in our forward plan (Section 5).

We then explore some of the market reforms being considered, consulted on, and introduced as part of the Market Renewal Program (MRP). These reforms are intended to meet Ontario's future needs at the lowest cost by improving the supply, scheduling and pricing of electricity. Some of these reforms are being introduced in 2020 and may further influence our market selection decision, whilst others are being developed over a longer timeframe, and in some cases have yet to be decided on. We consider these as we look beyond the project and our path to commercialisation.

3.1 Market frameworks in Ontario

3.1.1 Current Ontario markets

The following markets and programmes in Ontario have been assessed to determine their suitability with distributed energy resources, and for project participation and beyond.

- Real-time Energy Market
- Demand Response Auction (DRA)
- Industrial Conservation Initiative (ICI)
- Real-Time Operating Reserve
- Ancillary Service Market

Real-time Energy Market

History

The IESO administers, governs and operates three types of wholesale electricity market:

- Real-time markets
- Financial markets
- Procurement markets

The real-time markets for energy and operating reserve form the core of the IESO administered markets and affect the actual delivery and use of electricity. The IESO real-time energy market, also known as a physical market, opened in May 2002 and serves as a platform for continually balancing electricity generation (supply) and load (consumption).

The IESO determines the amount of energy to be consumed or supplied by each company, and the market clearing price (MCP) for that energy based on bids and offers submitted by consumers and suppliers at five minute intervals. These bids and offers determine the dispatch instructions issued by the IESO to each dispatchable facility for each five minute interval of every day. The dispatch instructions specify the required amount of energy that is to be injected or withdrawn for each interval.

Most resources participating in the real-time energy market have obligations to submit bids and offers day-ahead. See Day-Ahead Commitment Process (DACP).

Forecasting the market opportunity is outside the scope of this document, but it will be a worthwhile exercise beyond the project. The IESO provides a number of valuable resources for analysing historical capacity needs, market prices and other factors. Found in their public reports database and data directory.

Participation

There are different ways to classify the roles that participate in the IESO administered markets. Those with physical assets typically fall into the following categories based on the asset type and whether they are able to respond to five-minute signals in the market:

> **Dispatchable generators** must be able to adjust the amount of electricity they generate in response to dispatch instructions issued as often as every five minutes by the IESO (24 hours a day, 365 days a year). Most of the energy supply in Ontario is provided by dispatchable generators.
>
> **Non-dispatchable generators** typically have little control over their fuel source such as a small hydro generator on a river. They submit forecasts of energy production and are paid the Hourly Ontario Energy Price (HOEP) which is calculated using the average of the 12 five-minute Market Clearing Price (MCP) during the hour.

Dispatchable loads must also be able to adjust their power consumption in response to dispatch instructions issued as often as every five minutes by the IESO (24 hours a day, 365 days a year). Dispatchable loads account for only a small portion of the energy consumed in Ontario.

Non-dispatchable loads or consumers draw electricity from the IESO-controlled grid to meet their needs. They agree to pay the HOEP (wholesale market price) for electricity at the time of consumption, which is set on an hourly basis. An LDC is another example of a non-dispatchable load.

For dispatchable loads, the IESO dispatch instructions are based primarily on:

- An offer to sell electricity at specific prices relative to the bids and offers from other facilities - generators
- A bid to purchase electricity at specific prices relative to the bids and offers from other facilities - loads

The other factors that influence dispatch instructions are:

- Respect for constraints and transmission limits to preserve grid integrity
- A facility's ability to adjust its generation or consumption levels

Eligibility

Any company with physical assets directly connected to Ontario's IESO-controlled grid to convey electricity into, through, or out of the grid must become a market participant. Embedded assets are connected to a distributor's lines, which are themselves connected to the IESO-controlled grid.

The eligibility criteria are not the same for all market participants, but any participant with physical connections to the grid must register their facilities with the IESO and obtain appropriate licenses from the Ontario Energy Board. They are required to have registered interval meters to measure energy flows and must meet credit requirements to protect other participants in the event of default.

At 17 Mar 2020, there were 392 registered market participants either active, or pending activation, in energy and transmission rights markets. There are a further 188 participants operating in other roles such as programme participants.

Note: Transmitters, boundary entities and participants without physical assets such as wholesalers and retailers are outside the scope of this document.

UK Equivalent

Like Ontario, the balance of electricity supply and demand in the UK is primarily achieved by suppliers, traders, and generators trading in the competitive wholesale electricity market. Contracts for electricity can be struck over timescales ranging from several years ahead to on-the-day trading markets. Unlike Ontario, where the wholesale market is administered by the IESO, trading in the UK can take place bilaterally or on exchanges.

National Grid is the closest equivalent to the IESO in the UK. On 01 Apr 2019 National Grid to split into two legally separate companies.

> National Grid Electricity Transmission (**NGET**) - Is the owner of the high-voltage electricity transmission network in England and Wales. It is responsible for building and maintaining the network safely, reliably and efficiently. It connects sources of electricity generation to the network and transports it onwards to the distribution system[1].
>
> National Grid Electricity System Operator (**NGESO**)[2] - Has overall responsibility for balancing electricity supply and demand in Great Britain. It has a number of tools that it can use to do this, including the Balancing Mechanism (BM). It is also responsible for running electricity capacity auctions, coordinating and administering aspects of industry rules and codes and supporting efficient transmission network development.

The BM is Great Britain's core flexibility market. It is used to balance electricity supply and demand close to real-time. Where NGESO predicts that there will be a discrepancy between the amount of electricity produced and that which will be in demand during a certain time period, they may accept a 'bid' or 'offer' to either increase or decrease generation (or consumption). The balancing mechanism is used to balance supply and demand in each half-hour trading period of every day.

Great Britain is seeing a transformation in its energy mix as it moves towards a decarbonised energy system. Changes are being made to the BM to make it more accessible to non-traditional providers and aggregators. Widening access so that smaller distributed assets can more easily participate by reducing and streamlining the administrative overheads for owners and operators of smaller assets. The objective is to deliver more flexibility, lower carbon, increased competition and reduced transmission costs for consumers.

Demand Response Auction (DRA)

History

Demand response in Ontario is used to cost effectively manage energy demand and reduce peaks by asking participants to reduce their electricity consumption in response to market prices and system needs. The IESO started exploring the potential system benefits of demand response before launching the Demand Response Auction in 2015 for the purpose of procuring demand response capacity through a competitive process.

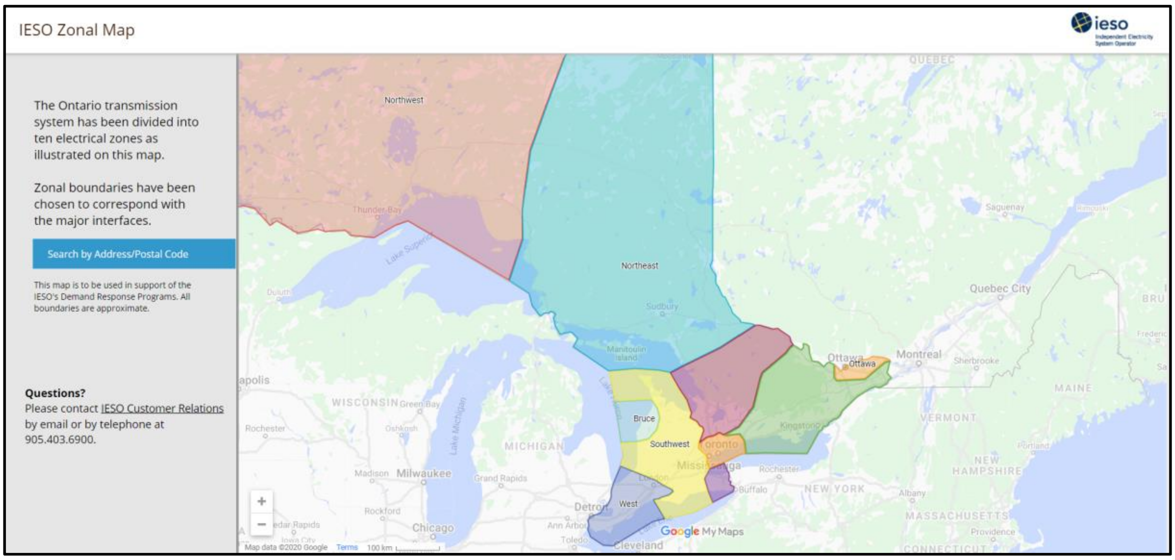
[1] Scottish Power Energy Networks and Scottish and Southern Electricity Networks are responsible for running the transmission network in Scotland. Whilst Northern Ireland Electricity Networks manage the network in Northern Ireland.
[2] Eirgrid is the Transmission System Operator (TSO) in Northern Ireland.

Around the same time the IESO inherited a demand response program when they merged with the Ontario Power Authority in 2015. To manage the transition from the program they inherited to the DRA they created the Capacity Based Demand Response (CBR) program. Whilst the rules for both programs were similar, the DRA's incentives and penalties better reflected customers' value to the system operator. The two programs operated in parallel until any remaining CBDR participants switched to the DRA when the last of the CBDR contracts expired in 2018.

Demand response auctions are held annually and companies submit auction capacity offers for one or two seasonal commitment periods:

- Summer - May to Oct
- Winter - Nov to Apr

Seasonal commitment periods are used to allow for resources that have different performance profiles over different seasons. Companies may choose to submit offers for one or more zones out of Ontario's ten electrical zones. Each zone has a set of demand response zonal constraints defined, including different clearing prices in different zones.



Source: IESO Zonal Map Tool

The last auction to obtain capacity in the DRA program was held in Dec 2019. This will be the final auction as the IESO is replacing the DRA in Jun 2020 with the Capacity Auction (CA) to enable competition between additional resource types.

The results for the auction held in Dec 2019 published by IESO in their post-auction report lists the scale of participation as follows:

- 52 companies were registered as participants
- 14 of these were new companies compared to the previous year
- 3 of these were local distribution companies[3]

[3] Determined from the IESO website, Registered Participants, Mar 2020

- 23 companies submitted capacity qualification
- 22 successfully cleared capacity in the auction
- 1 MW is the smallest capacity qualified and cleared

Summer Commitment Period (2020)

- 1,432 MW of capacity qualified and 858 MW of capacity cleared
- The average clearing price was 286.16 $/MW-day offering participants an aggregate revenue opportunity for availability of ~$27.7M

Winter Commitment Period (2020/2021)

- 1,490 MW of capacity qualified and 919 MW of capacity cleared
- The average clearing price was 210.31 $/MW-day offering participants an aggregate revenue opportunity for availability of ~$23.5M

Auction parameters for Summer and Winter Commitment Periods

- Target Capacity - 675 MW
- Auction Reference Price - 413 $/MW-day
- Minimum Clearing Price - $/MW-day
- Maximum Clearing Price - 516 $/MW-day[4]
- Minimum Capacity Limit - 0 MW
- Maximum Capacity Limit - 1215 MW
- Maximum Capacity at the Maximum Clearing Price - 540 MW

Participation

Companies that are successful in the demand response auction receive a demand response capacity obligation for the commitment period(s). A company is required to make their demand response capacity obligation available for dispatch throughout this period by submitting bids in every hour of the availability window(s).

- Summer (business days 12:00 to 21:00 EST)
- Winter (business days 16:00 to 21:00 EST)

In return for providing capacity, companies receive availability payments associated with their demand response capacity.

There are two resource types that can participate in the DRA:

1) Dispatchable Load (DL) - can respond to a 5 minute dispatch instruction. They must be revenue metered by the IESO. They are considered physical demand response resources.

2) Hourly Demand Response (HDR) - cannot respond to a 5 minute dispatch instruction. They are not typically revenue metered by the IESO, and metered by the LDC instead. They are considered virtual demand response resources. Where

[4] A multiple of 1.25 times the reference price

they are physical resources, revenue metered by the IESO, they are referred to as non-dispatchable loads.

Demand response market participants must submit a demand response energy bid on a daily basis to meet their demand response capacity obligation (see Day Ahead Commitment Process). When the IESO forecasts the need for a participant's capacity, a stand by notice is received the day before or prior to 08:00 on the same day. If capacity is required, an activation notice is received approximately two hours prior to the event start time. HDR facilities are typically dispatched for one up-to four consecutive hours.

Historically, economic and emergency dispatch events are rare. As a result, facilities are typically dispatched four times or less per year as part of program testing requirements. Two test activations may be scheduled during each commitment period for dispatchable loads and HDR resources. Participants will still need to respond to these tests and demonstrate their ability to reduce consumption. Failure to do so can result in non-performance charges or a compliance investigation.

Non-performance charges promote compliance with capacity obligations.Reasons for planned non-performance events must be given and outages requested. There are four types of charges that may apply:

- Availability
- Administration
- Dispatch
- Capacity

Demand response settlement lags behind the real-time energy market settlement by a month, and so the IESO supplements settlement data to ensure participants have all the information needed to reconcile their demand response activity.

Eligibility

The amount of demand response capacity a company can provide can be not less than **1 MW** per electrical zone. This capacity can be provided through load interruption or behind-the-meter generation. Common reduction examples include HVAC adjustment, dial back of pumps, and modification of manufacturing processes.

Commercial, industrial and institutional (C&I) resources can participate as:

- Dispatchable loads - IESO revenue metered (DL)
- Non-dispatchable loads - IESO revenue metered (HDR)
- Virtual loads - not IESO revenue metered (HDR)

Residential resources may also participate as:

- Virtual loads - smart-metered (HDR)

As long as the total capacity is above the 1 MW threshold there are no limits to the number of residential resources that can contribute to a demand response obligation. To meet the 1 MW threshold residential contributors can be mixed with C&I contributors.

To take advantage of the different baselining methodologies the obligation can be split between two virtual resources - one for C&I contributors and another for residential contributors. The residential methodology uses two groups of contributors:

- **Treatment group** - contributors are activated to provide demand response upon receipt of the demand response standby and activation notice; and
- **Control group** - randomised contributors serve as a proxy for baseline consumption; therefore, are not activated to provide demand response.

Companies must provide a load reduction plan to qualify capacity and maintain sufficient capacity to meet their demand response obligation. That capacity must be able to respond to dispatch instructions throughout the entire commitment period. Amongst other administrative activities, companies must:

- Declare the LDC has been notified of the contributors' participation in the demand response auction.
- Identify if resources participate in other demand response or conservation initiatives[5].
- Transfer an auction deposit and lodge prudential support (credit cover) to determine creditworthiness.
- For resources that are not IESO revenue-metered (Virtual):
    - Submit monthly five-minute interval measurement data to the IESO for C&I by the IESO for settlement purposes.
    - In certain conditions, also submit an additional two months of historical measurement data to the IESO.
    - Submit aggregated 60-minute interval measurement data to the IESO for residential resources for days they received demand response activations.
    - Specify if data is collected directly from the meter via remote interrogation, or provided to the participant by their LDC.
    - Upload a Record of Installation (ROI) for each LDC meter installation associated with a site.
    - Provide a Single line diagram (SLD) when more than one LDC metering installation is associated with a site, or when the demand response type is behind-the-meter generation.
    - Retain individual contributor meter data and supporting registration documentation for audit purposes by the IESO.

UK Equivalent

The Short Term Operating Reserve (STOR) program is the closest UK equivalent to the IESO Demand Response Auction. It is operated by NGESO to help manage actual demand on the system when there is unforeseen generation unavailability or if demand is

[5] Clean energy supply, standard offer programs, or peaksaverPlus for example.

greater than forecast.

The two programs share common characteristics in that dispatches are triggered by a central signal, there is an opportunity for demand reduction, and aggregators are typical program participants. Both programs also offer availability payments and utilisation fees. However, the procurement processes and technical requirements vary slightly. For example:

Requirements	STOR	DRA
Tenders per year	3	1
Seasons per year	6	2
Availability windows per day	2	1
Minimum response time (mins)	20 / 240	150
Minimum duration (hours)	2	1
Recovery period (hours)	20	None

STOR offers two routes to market.

- Committed Service - Like the DRA, a participant must make the service available throughout the availability window unless technical or safety reasons prevent them from doing so. National Grid commits to buying all services offered.
- Flexible Service - Availability declarations are made and accepted on a weekly basis. National Grid is not obliged to accept and buy any of the services offered.

The EU Medium Combustion Plant Directive (MCPD) stipulates generators that take on balancing services contracts have to meet strict emissions limits, which unabated diesel cannot do. It was expected to have a significant impact on the number of diesel generators providing STOR services. There appears to be no such restriction on diesel generator participation in the DRA.

Both programs are fairly well established but the DRA program is closing whilst STOR is currently suspended and its future is in doubt. Under the EU's Clean Energy Package contracts must be procured no more than a day ahead – and can be for no longer than a day, which STOR contravenes.

Industrial Conservation Initiative (ICI)

History

The Hourly Ontario Energy Price (HOEP) includes a global adjustment (GA) capacity charge component that covers the provincial cost of building new electricity infrastructure, maintaining existing resources, and providing conservation and demand management programs. The GA was introduced in 2006 and effectively covers the difference between electricity market rate and the higher rate paid to generators[6]. Since the Green Energy Act

[6] In 2005, Ontario began offering long term, fixed price contracts at above market rates to new generators to encourage investment in this sector.

was passed in 2009, GA charges have been on the rise.

In 2011, the Industrial Conservation Initiative (ICI) was introduced as a form of demand management that by reducing demand during peak periods helps:

i) defer the need for investments in new electricity infrastructure[7]

ii) helps participating customers to manage their GA costs

GA is added monthly to electricity bills of all electricity customers and varies monthly depending on the market prices (HOEP). Customers with an average peak demand of 50kW or higher pay for GA as either a Class A or Class B customer (typically C&I).

Class A customers	Class B customers
• Have an average 12 month peak demand above 500 kW • Have the opportunity to pay GA based on how much their peak demand contributed to provincial peak demand. • Can manage their GA through the Industrial Conservation Initiative.	• Have an average 12 month peak demand of 50 kW up to 500 kW. • Typically pay GA through their regular billing cycle with their local distribution company • Are not eligible to manage GA through the Industrial Conservation Initiative.

Class B buildings pay far more towards the GA than Class A. As shown for 2018 in the table below.

Total GA Fee (CAD)	Total Class A Payment	Total Class A Payment
$11,196.2M	$2,016.6M (19%)	$9,179.6M (81%)

Class A customers who participate in the ICI, typically pay GA based on their percentage contribution to the top five peak Ontario demand hours over a 12-month period. The savings for ICI participants can be significant especially as buildings get better at reducing their peaks.

When the ICI was introduced, the Class A eligibility requirement was an average peak demand of 5 MW or greater but the demand requirement has lowered over the years:

- 2015 - 3 MW
- 2017 - 1 MW
- 2017 - 500 kW

This has led to debate over the fairness of the ICI program. Whilst more and more buildings are eligible to participate in the program this has increasingly shifted the GA costs to the Class B rate payers. The result is that, percentage wise, Class A buildings pay much less towards the GA compared to the amount of electricity they consume. The Ontario government undertook electricity price consultations throughout 2019. The ICI was a main theme but there has been no change in program direction to date.

[7] In 2016, the ICI is estimated to have reduced peak demand by 1,300 MW, seeing highs of 17,800 MW and lows of 12,900 MW.

Participation
The ICI offers a great opportunity for customers to reduce the cost of their energy via demand management[8]. The better that a participant customer can forecast the top five hours of peak demand and shift their demand accordingly, the more they will be able to take advantage of the initiative. The top five hours of peak demand in a year are those occurring on different days in which the greatest number of MW of electricity was withdrawn from the IESO-controlled grid by all consumers of electricity in Ontario. Common ways to determine when these hours are more likely to occur are: ● Time of year ● Time of day and days of the week ● IESO Class A-specific tools ● IESO Adequacy Reports Customers connected to a distribution network are advised by the IESO to work with their local distribution company to better understand their demand profiles and learn what programs and strategies are available for helping to manage electricity costs.
Eligibility
To be eligible to participate in the ICI, customers must have an average monthly peak demand greater than 500 kW during an annual base period from May 1 to Ap 30. There are various thresholds above the 500 kW peak demand figure that determine opt-in and opt-out rules. Separate load facilities, even if they are under the same ownership, cannot be aggregated in order to qualify as Class A. In other words, a customer cannot add together a load facility with an average monthly peak demand of 350 kW and another load facility with an average monthly peak demand of 750 kW.
UK Equivalent
Given they are both forms of peak load avoidance, there is commonality between the Industrial Conservation Initiative and the UK Triads. National Grid ESO identifies three Triads each year in order to calculate the Transmission Network Use of System (TNUoS) charges a facility will incur. TNUoS charges are one of the charges built into business energy costs. TNUoS charges were introduced to help maintain supply and reduce peak energy demand during the winter months. Such transmission costs can be reduced if demand is decreased when a Triad is expected. A Triad represents one half-hour period of the highest demand for electricity. When power demand peaks, the transmission network is under maximum pressure to deliver power where it's needed and causes generators to bring online more expensive (and less efficient) production capacity. These half-hourly periods normally occur between 16:00 and 18:00 on weekdays between November and February. This is when industrial demand coincides with residential demand and they tend to occur during the three coldest periods of winter.

[8] Enel X estimates that 1 MW reduction during peak periods through ICI can save $500,000 on average in GA charges.

National Grid ESO will only confirm Triad times once they have reviewed the season's settlement data so a number of companies offer Triad alerts to help identify when a Triad period is likely to occur. TNUoS savings are dependent on the level of energy reduction but can be significant. Not to mention the impact the reduction in consumption has on the energy bill.

Real-Time Operating Reserve

History

Having enough energy to meet demand is an important part of reliability. Sufficient generation is always scheduled to meet demand, but there may be occasions when the balance between generation and load is affected by an unanticipated event such as:

- A sudden, unexpected increase in demand
- A generation loss, or several generators failing to follow dispatch instructions
- The loss of a transmission element, which removes generation or demand

Stand-by power or demand reduction that can be called upon on short notice is required to restore the balance in the case of such an event. This spare capacity is called operating reserve (OR). OR is also used for voltage reduction to solve local reliability problems and capacity or energy emergencies, as the amount of energy being consumed in Ontario is reduced.

Ontario's IESO administers three separate Real-time Operating Reserve Markets that are inextricably linked with the Real-Time Energy Market and share the same history. They provide a market-based way for the IESO to restore balance for a short period of time until normal operating conditions are re-established.

- 10S - 10 minute synchronized (spinning) reserve
- 10N - 10 minute non-synchronized (non-spinning) reserve
- 30R - 30 minute reserve (synchronized or non-synchronized)

They are determined by the time required to bring the energy into use and the physical behaviour of the facilities that provide it. There must be enough 10-minute reserve to cover the largest single contingency that can occur.

NERC and the NPCC set reliability standards that describe the performance obligation and amounts of operating reserve required. Namely, the largest single unexpected event (contingency) plus half of the second largest contingency that could occur. Typically, this means the loss of Ontario's one and a half largest generators.

The IESO is a voluntary member of a group of interconnected transmission system operators who participate in Shared Activation of Reserve (SAR). SAR allows participating areas to more quickly recover from a significant supply loss. Members of the NPCC and PJM may participate, and include:

- New York ISO (NYISO)
- ISO-New England (ISO-NE)
- Maritimes
- Pennsylvania-Jersey-Maryland (PJM)

- IESO

Forecasting the market opportunity is outside the scope of this document, but it will be a worthwhile exercise beyond the project. The IESO provides a number of valuable resources for analysing historical capacity needs, market prices and other factors. Found in their public reports database and data directory.

Participation

Market participants can offer operating reserve to the IESO-administered markets at the same time that they bid or offer energy.

Every five minutes a market clearing price and schedule is determined for each of the three OR markets. Schedules tell participants how much of each class of reserve they are obligated to provide if activated and are used for settlement. The IESO dispatch algorithm optimises schedules for both energy and operating reserve simultaneously using these rules:

```
Generator – Energy Schedule + OR Schedule ≤ Generator Energy Offer
Load – Load Energy Bid ≥ Energy Schedule ≥ OR Schedule
```

The algorithm considers the offers in order of increasing price, then selects the necessary resources to satisfy its requirements. It can use offers not required for one reserve class to satisfy the requirements for a 'lower' class (eg. 10S > 10N > 30R).

Scheduling dispatch instructions are received by loads and generators at the beginning of each 5 minute interval in the same way as the energy markets. New schedules are only sent when there is a change from an earlier instruction.

Typically, OR requirements are entirely met through the scheduling of resources based on participant offers. When the market cannot provide enough supply to meet forecast demand and reserve requirements, out-of-market control actions to manage the capacity shortfall are taken. Control action operating reserve (CAOR) activation can happen at any time and is based on the energy offer price associated with the resource, not the OR offer price.

Activated participants must meet their dispatch instructions or face losing their operating reserve payments, or a compliance investigation, or sanctions that can result in exclusion from further participation in the OR markets.

Operating reserve offers are essentially standby offers. All accepted offers are paid the market clearing price for that class of operating reserve, regardless of whether or not the reserve is actually used. As described above, for the operating reserve that is actually used, the suppliers are paid for the energy provided.

Eligibility

Only dispatchable generators and loads may participate in operating reserve markets. However, they can offer operating reserve in any of the three markets as long as they are

able to:[9] 1. Provide the reserve in the time frame specified by the market 2. Sustain supplying operating reserve energy for up to one hour A bid or offer in the real-time energy market for an amount greater than or equal to the quantity of the operating reserve offer is also required.
UK Equivalent
There is no direct equivalent to the IESO Real-Time Operating Reserve market in the UK. The BM and STOR programmes described above provide NGESO generation or demand reduction on short notice to restore balance. However, their programme characteristics, procurement cycles, response and duration requirements are different. Two other reserve services available to the NGESO worth mentioning here are: **Fast reserve** - Fast reserve provides rapid and reliable delivery of active power to control frequency changes through increasing output from generation or reducing consumption from demand sources. It can be provided by generators connected to the transmission and distribution networks, storage providers and aggregated demand-side response (although it has a high 25 MW floor). Providers can offer other balancing services outside of their tendered fast reserve windows. **Demand Turn Up** - Developed to allow demand-side providers to increase demand as an economic solution to managing excess renewable generation when demand is low. It encourages large energy users and generators to either increase demand or reduce generation at times of high renewable output and low national demand. It is open to any technologies that can offer the flexibility required. It is not possible to provide other services alongside demand turn up. In addition, a new **Replacement Reserve** product is currently being introduced as part of the Electricity Balancing Guidelines that aims to establish a pan-European market for balancing energy. The goal is a harmonised service across participating European Transmission System Operators (TSOs) for the provision of both an increase and decrease of active power. The project implementing this product is referred to as Trans European Replacement Reserves Exchange (TERRE) and is due to go live some time in 2020[10]. The following European TSOs are currently participating:

[9] Boundary entities (import/export) may also offer 10 minute non-synchronized reserve and 30 minute reserve but these are out of scope of this document.

[10] TERRE was due to go live in Jun 2020 but due to COVID-19 it has been delayed. At the time of writing no specific go live date has been published.

TERRE members (8 TSOs)	
Czech Republic	čeps a.s.
France	Rte
Great Britain	nationalgrid
Italy	Terna
Poland	PSE
Portugal	REN
Spain	RED ELÉCTRICA DE ESPAÑA
Switzerland	swissgrid

It is expected that in the future additional TSOs, using the RR product will join the project.

Ancillary Service Market

History

Ancillary services are required to maintain the reliability of the power system. The IESO monitors the security and adequacy of the power system 24 hours a day, 365 days a year.

The ancillary service market, also known as the procurement market, is considered another physical market and is used to contract four ancillary services:

- Regulation service
- Certified black start facilities
- Reactive support and voltage control service
- Reliability must-run

Regulation service is also referred to as frequency response and helps correct variations in power system frequency as a result of short-term changes in electricity use that might affect the stability of the power system. Its core objective is to maintain the consistent frequency of the power system. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises.

Like the UK, a number of factors are increasing instability:

- Intermittent generation and weather pattern uncertainty
- Autonomous embedded generation not managed by the IESO
- Non-linear demand patterns cause by electrification (eg. transport)

The service has historically been provided by generation facilities that vary their output in response to signals sent by the IESO (typically fulfilled by the Real-Time Operating Reserve Market). However, since 2012, the IESO has looked towards increasing the participation of alternative technologies such as aggregated loads, flywheels and battery storage.

Since 2017, the IESO has been increasing the amount of regulation services through target setting, competitive procurement (such as the 2017 Regulation Service RFP), and standardization and simplification of regulation agreements. It is also tracking emerging technologies.

Certified black start facilities help system reliability by being able to restart their generation facility with no outside source of power. In the event of a system-wide blackout, black start facilities would be called on during restoration efforts by helping to re-energize other portions of the power system.

Reactive support and voltage control service is contracted from generators and allows the IESO to maintain acceptable reactive power and voltage levels on the grid. All generating facilities that are injecting energy into the IESO-controlled grid are required to provide reactive support and voltage control service in accordance with the market rules.

Reliability must-run (RMR) contracts are used to ensure the reliability of the IESO-controlled grid. A RMR contract obligates a generator to offer the maximum amount of energy and operating reserve in a commercially reasonable manner and in accordance with stated performance standards. No generating stations have been contracted to provide RMR since Dec 2013.

Only the regulation service is of particular interest to this project and so only this service has been considered when researching participation, eligibility and the UK equivalents.

Participation - Regulation service

This regulation service is typically provided by contracted generation facilities with automatic generation control (AGC) capability, which permits them to vary their output in response to signals sent by the IESO. Terms and conditions of contract include:

- Minimum of ±100 MW of AGC must be scheduled at all times
- Minimum overall ramp rate requirement for Ontario is 50 MW/minute
- Payments comprise fixed and variable costs

The IESO regulation signal complies with NERC standards and is provided as a MW quantity at a frequency of up to once every two seconds. The IESO has published regulation signal sample data since Mar 2018.

In 2017, the IESO tendered for ~50 MW of scheduled regulation capacity over and above the 100 MW it typically schedules every hour. The RFP allowed for alternative technologies such as battery storage and was open to new build facilities as well as existing ones.

Eligibility - Regulation service

Eligibility criteria vary between procurement rounds and any overall capacity and cost caps as well as individual facility criteria are set out in the associated RFP.

For example the RFP in 2017 had a maximum overall capacity of 50 MW. It also had a minimum facility capacity of ±2MW, a minimum duration of 6 minutes, and a minimum ramp rate of 7 MW/minute.

UK Equivalent - Regulation service
Unlike in Ontario, and most of North America, where power systems operate above or below 60 Hz, National Grid ESO is obliged to control UK system frequency at 50 Hz (plus or minus 1%). They do this by ensuring there is sufficient generation and demand held in readiness to manage all credible circumstances that might result in frequency variations. Frequency response in Ontario cannot be considered a stand alone ancillary service product in the same way as it is in the UK as it is closely tied to the real time markets. Unlike Ontario where a central signal triggers a response to frequency changes, facilities in the UK monitor the frequency and respond when needed. National Grid ESO categorise frequency response as: **Dynamic frequency response** - a continuously provided service used to manage the normal second by second changes on the system **Non-dynamic frequency response** - usually a discrete service triggered at a defined frequency deviation. Also known as static frequency response They operate a number of different frequency response products to meet their ever changing requirements. Each type has different technical requirements, procurement and qualification processes. The two principal product types are: **Mandatory Frequency Response (MFR)** - This type is probably the most similar to the Ontario regulation service as it is provided by generation facilities. Some facilities are obliged to provide MFR. **Firm frequency response (FFR)** - Can provide both dynamic and non-dynamic response and is open to generators connected to the transmission and distribution networks, storage providers and aggregated demand side response. The three different response speeds are common across both products: ● Primary response - 10 second response, which can be sustained for a further 20 seconds ● Secondary response - 30 second response, which can be sustained for a further 30 minutes ● High frequency response - 10 second response, which can be sustained indefinitely. As instability increases, NGESO are in increasing need of faster-acting frequency response. Over the next few years frequency procurement in the UK is expected to rise substantially from 300 MW to 3 GW. NGESO will be introducing new frequency response products to meet this need. The first is Dynamic Containment that will be rolled out in 2020 and will require one second response times. Two more products will follow and together these three will eventually replace the products described above.

3.1.1.1 Day Ahead Commitment Process (DACP)

Whilst not a market as such, the Day Ahead Commitment Process (DACP) is fundamental to the operation, efficiency and reliability of the Ontario energy markets. The DACP provides the IESO with a dependable view of the next day's available supply and anticipated demand and allows them to commit certain dispatchable resources, in return for a financial guarantee. It provides energy-limited resources that are unable to run continuously an opportunity to meet reliability needs.

Facilities, loads or generators, submit bids or offers known as dispatch data to the DACP if they wish to participate in the next day's real-time and demand response markets (and capacity market in the near future). As the name suggests, they do this on a fixed timeline published by the IESO.

The DACP uses a day-ahead calculation engine (DACE) to optimise energy and operating reserve for the 24 hours of the next day. The DACE determines the least-cost security-constrained solution for a dispatch day based on the bids and offers submitted by all resources.

Market participants may continue to submit dispatch data and revisions after the DACP deadline has passed (10:00 EST the day ahead) until two hours prior to the dispatch hour, subject to restrictions.

3.1.2 Known Ontario market engagements

The Market Renewal Program is introducing fundamental reforms to the province's electricity markets and is giving rise to significant activity across the Ontario energy sector. Below we highlight just a handful of the initiatives being undertaken, which are of particular interest to this project and beyond.

Capacity Auction
Summary
The IESO's Capacity Auction will replace the existing Demand Response Auction (DRA) in Jun 2020. It is intended to enable competition between additional resource types. Some specific tasks have been introduced to participate in the auction process and dispatchable generation capacity may participate when it was unable to do so before. However, it is much the same as the DRA in terms of market rules and mechanics. At least for the time being.

The Capacity Auction is sometimes referred to as the Transitional Capacity Auction (TCA). It should not be confused with the Incremental Capacity Auction (ICA) which the IESO announced they would terminate on completion of engagement activity and market design.
Status
The first capacity auction is scheduled for 24 Jun 2020 for the obligation periods: Summer - May 2021 to Oct 2021 Winter - Nov 2021 to Apr 2022 A pre-auction report is expected in Apr 2020 and companies must apply to participate in the auction by 15 May 2020. Following the auction, successful participants must become authorized as Capacity Market Participants (CMPs). They may then register resources to deliver on their capacity obligations. The participants will receive availability payments for providing auction capacity, subject to non-performance charges.

Energy Payments for Economic Activation of Demand Response Resources
Summary
The potential benefit to demand response resources of this engagement is to rectify a disadvantage that provides no mechanism for them to recover their incremental costs of activation. At the same time the IESO seeks to determine whether there is a net benefit to electricity ratepayers if demand response resources are compensated with energy payments for economic activations. This is a complex issue and was an ongoing topic of discussion at the Demand Response Working Group (DRWG). The IESO then broadened the engagement and commissioned Brattle to support the research and analysis
Status
It is nearing the end of the research and analysis phase and the IESO decision and rationale will be published in May 2020 for stakeholder review before the final decision is made in Jun 2020.

Energy Storage Advisory Group
Summary
The Energy Storage Advisory Group (ESAG) advises the IESO in evolving policy, rules, processes and tools to better enable the integration of storage resources in IESO administered markets and encourage fair competition. They are tasked with identifying potential obstacles to participation, proposing mitigating strategies, and helping prioritise activities to address storage related issues and opportunities.

Status
The IESO released the Removing Obstacles for Storage Resources in Ontario report in Dec 2018. It recommends solutions to address the primary barriers preventing the fair competition of energy storage resources. The working group continues to meet and publish materials for feedback.

Improving Accessibility of Operating Reserve
Summary
The IESO has been experiencing issues with OR where the amount of scheduled OR is not fully accessible. This can create challenges for the IESO to recover the supply-demand balance after a system event, and result in unfair cost to the market. The purpose of this engagement is to better understand and develop potential solutions to this issue.
Status
This remains an active engagement. Solutions to the problem were proposed in Jul 2019 and the IESO is still working through the feedback and ironing out the details of the solution.

3.2 Market frameworks in Alberta

3.2.1 Current Alberta markets

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

3.2.1 Known Alberta market engagements

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

4 Technology Overview

Another factor that will determine our market selection decision is the suitability of the existing software and hardware solutions of our two technology project partners, Kiwi Power and Opus One. This aspect is less significant given the flexibility and scalability of both solutions, but it deserves some consideration due to the time limitations for design, development, deployment, operation, testing and reporting.

In this section we summarise the existing capabilities of the Kiwi Power and Opus One solutions independently. We also consider the systems of the local distribution company, Lakeland, that will need to be integrated. We conclude with a high level view of the interaction between the separate solutions and the interoperability necessary to produce a fully integrated solution that meets our project objectives and can be applied more widely across Canada, the UK and internationally.

4.1 Overview of Kiwi Power solution

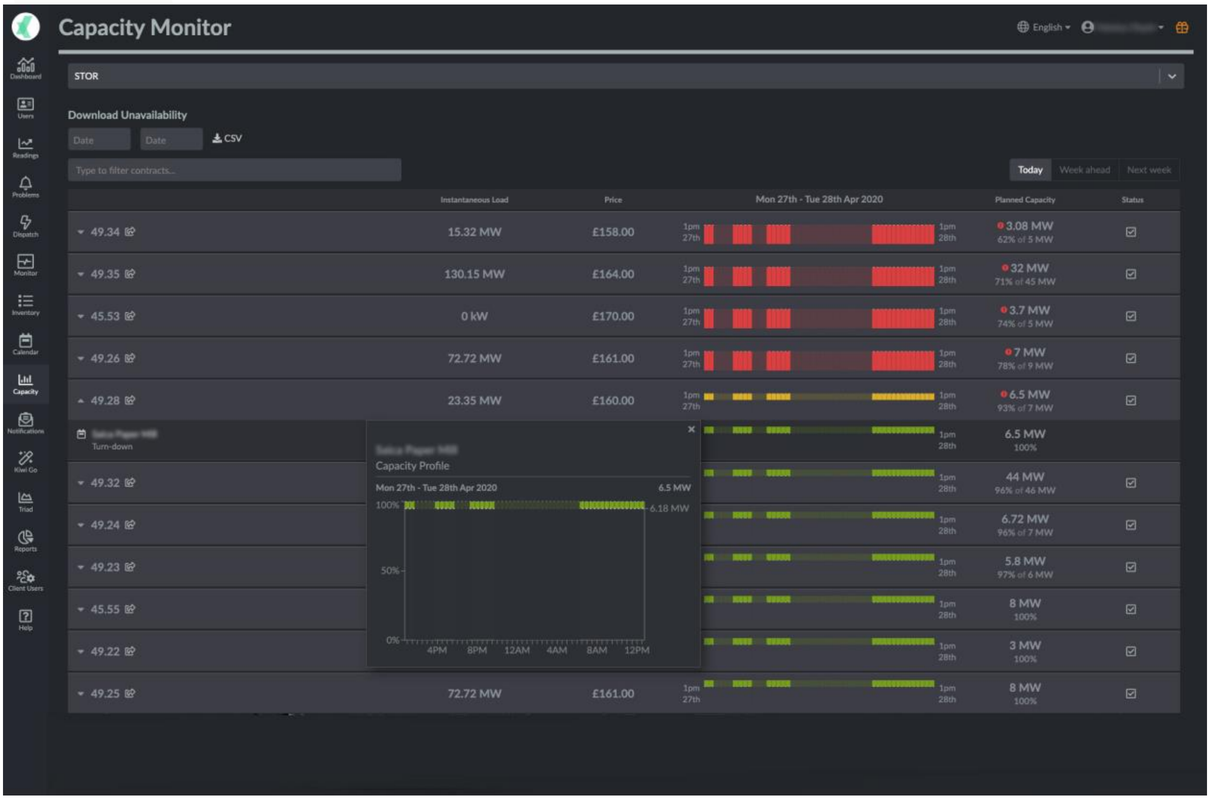
Kiwi Power combines expertise and technology to offer solutions in the Virtual Power Plant (VPP) and Distributed Energy Resources Management Systems (DERMS) sector allowing our clients to extract maximum value from their flexibility assets. Specifically, Kiwi Power solutions provide the ability to forecast, monitor, control, aggregate, optimise and monetise distributed energy resources across a variety of use cases. Our platforms are amongst the leading low-cost, easy-to-use, secure, reliable and scalable end-to-end solutions available for the management of DERs globally.

Kiwi Power offers two key products, Komp and Collar, built on the same underlying technology platform but meeting different use cases for unique target customers. The table below shows the target customers, key features and use cases for Kiwi Power platform. It is followed by screen captures from the user interface of each product.

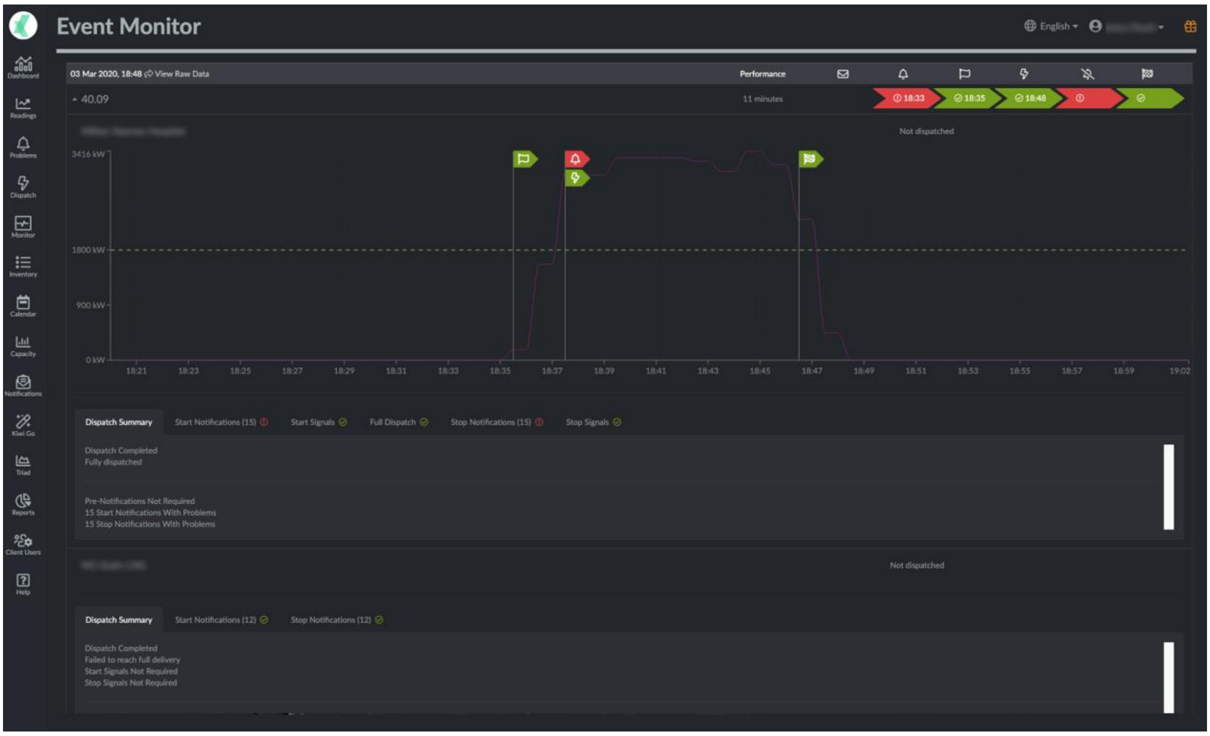
	Komp	Collar
Target Customers	• Utilities • Aggregators • Asset owners • Battery operators	• Distribution System Operators • Local Distribution Companies
Main Features	• Cloud-based Virtual Power Plant (VPP) and Energy Management System (EMS) platform	• Cloud-based grid management platform

	• Low-cost modular hardware solution (Fruit) for local connectivity, monitoring and metering • Aggregation of static and dynamic assets • Optimal portfolio based dispatching • Battery SOC management • Automatic/manual scheduling, dispatching & monitoring • Asset performance monitoring • User Interface includes live metering data, SoC, frequency, power, etc. • API for dispatching assets, triggering notifications and meter data provision • System operator / wholesale market connectivity	• Allocation of customers to network constrained zones • Network operator and asset owner interaction to determine availability, acceptance and dispatch • Automated and manual dispatch of assets to meet local flexibility needs • Monitoring and display of dispatch with rolling 2hr forecast of capacity • Asset performance, settlement and billing reports • API for dispatching assets and meter data collection
Use Cases	• Static, dynamic and economic demand response • BTM & FOM batteries • Primary, secondary, tertiary ancillary services • Capacity Market • Balancing mechanism UK • Wholesale trading • Peak shaving • Increase self – consumption • Price arbitrage • Asset pooling • Stacking batteries with DR assets	• Enable Distribution Network Operators (DNOs) to stabilise their grid whilst deferring reinforcement leveraging flexible assets on their network

Komp - Showing battery energy storage system operating in Fast Frequency Response (FFR) in the UK

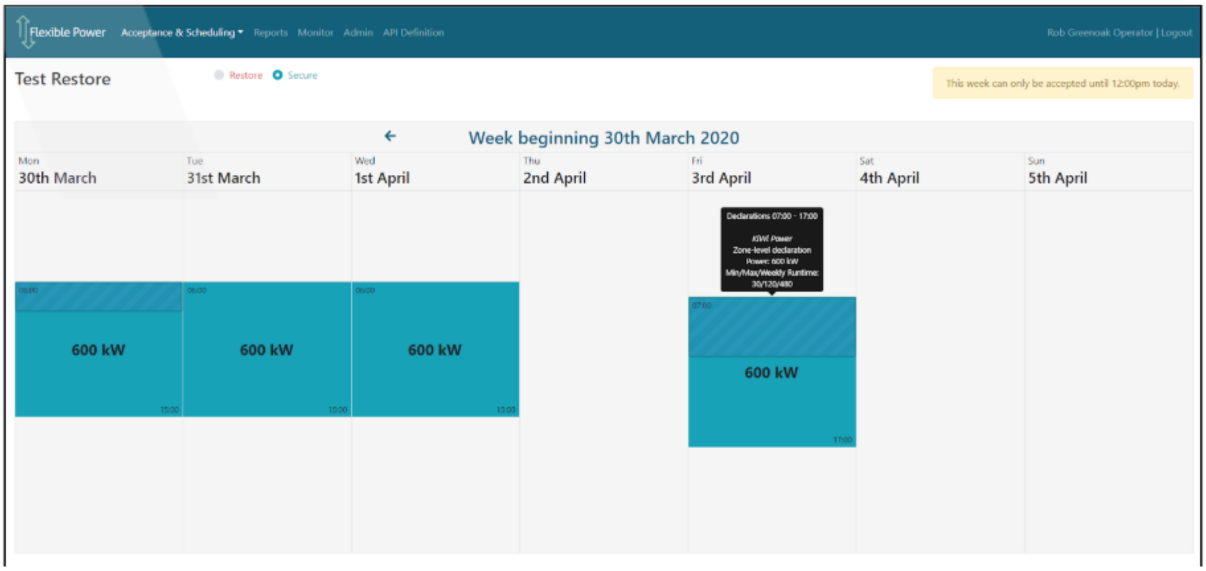


Komp - Showing capacity monitoring of active aggregated demand response contracts.



Komp - Showing dispatch monitoring of an active demand response contract.

Komp - Showing a summary of a dispatch of an active demand response contract.



Collar - Showing availability scheduling calendar functionality from the operator view.

4.1.1 Connectivity

Kiwi Power started as a UK demand response aggregator operating in frequency response and operating reserve markets. Subsequently, the company evolved to offer a technology platform able to connect a broad selection of DER assets with diverse revenue streams across multiple markets and jurisdictions. Kiwi Power's global footprint and market expertise allows us to:

- Develop strategies around operational parameters and revenue objectives for wide variety of assets

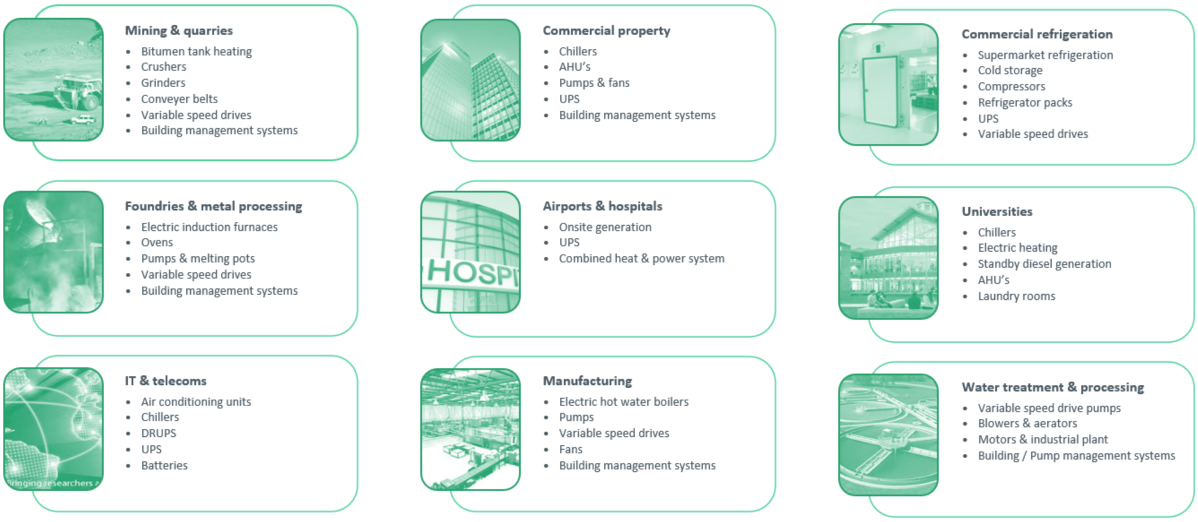
- Connect assets to markets, automate dispatch and provide real-time and decision making
- Optimise assets in all relevant markets and programmes, including stacking multiple revenue streams

4.1.1.1 Asset connectivity

Kiwi Power's platform is designed to be asset agnostic allowing a wide variety of assets to be connected and aggregated for market participation. Kiwi's expertise enables us to analyse and manage asset's characteristics which will determine what markets they are suitable to be enrolled in. For example:

- When those assets are available;
- How much control we have over them;
- How quickly they can respond to a signal;
- How long they can respond for; and
- For DNOs / LDCs specifically, their location

Kiwi Power has broad experience managing various asset types across different industries and sectors (a non-exhaustive list of examples are provided in the figure below). In addition, Kiwi manages more than 80 MW of battery energy storage systems in both Behind-the-Meter (BtM) and Front-of-Meter (FoM) configurations. For more details of how asset connectivity is facilitated using our unique Fruit devices, see the section below on integrated hardware.



Examples of asset types managed by Kiwi Power and the industries where they are typically situated.

4.1.1.2 Market connectivity

Kiwi Power connects to a wide variety of system operators and their markets. These include:

- Peak load
- Ancillary services (primary, secondary and tertiary reserves)
- Operating reserves
- Capacity markets
- Balancing mechanisms
- Imbalance
- Wholesale markets
- Constraint management

Our broad market exposure and participation ensures that our platform is market agnostic and highly configurable.

System Operator	SO Type	Connected Markets
National Grid (UK)	TSO	TRIAD Short Term Operating Reserve (STOR) Capacity Market (CM) Dynamic Fast Frequency Response (DFFR) Static Fast Frequency Response (SFFR) Enhanced Frequency Response (EFR) Balancing Mechanism (trading and FFR) Imbalance trading
RTE (France)	TSO	Frequency Restoration Reserve Manual (FRRm) Effacement Capacity Market
TenneT (Netherlands)	TSO	Manual Frequency Restoration Reserve (mFRR) Automatic Frequency Restoration Reserve (aFRR) Frequency Containment Reserve (FCR)
Elia (Belgium)	TSO	R3 Frequency Containment Reserve (FCR)
Swissgrid (Switzerland)	TSO	Tertiaerregelleistung
ERCOT (USA)	ISO	Coincident Peak Load Avoidance (4CP)
PJM (USA)	ISO	Coincident Peak Load Avoidance (5CP)
Western Power Distribution (UK)	DSO	Pre and post fault programmes: - Sustain - Secure - Dynamic - Restore

4.1.2 Solution architecture

All Kiwi Power's products are particular configurations/applications of the underlying Kiwi Power platform, meaning they all share the same underlying architecture and infrastructure. This enables deployment of common infrastructure at scale.

4.1.2.1 Software architecture

Kiwi Power deploys a robust software stack built by a strong in-house agile software delivery team with the following key highlights:

- Capturing all meter readings, permanently, in a high-throughput time-series database. This allows near-real-time recall of meter readings for real-time visualisations of asset performance or on-the-fly calculations and asset monitoring
- Storing all meter readings and system/operational data in a bi-temporal data warehouse. In practical terms, bi-temporality means end-users can ask questions such as: "What did we think the imbalance price for the next settlement period was at 4:17pm on Wednesday, given the information we had at that time?"
- Kiwi Power's veteran Scala development team use the Typelevel Scala stack which leads to principled functional programming in day-to-day work
- In contrast to microservices and monoliths, Kiwi Power's business-focused services drives business context thinking when delivering new features or evaluating the impact of proposed changes
- Kiwi Power's entire platform infrastructure, including compute nodes, databases, load balancers, gateways, networks and so forth are captured in code. This infrastructure-as-code approach allows Kiwi Power to spin up new environments or recover from problems rapidly
- Kiwi Power's extensive suite of REST APIs lets partners and clients access meter readings, coordinate dispatch of assets and integrate other platforms (such as energy trading systems) with ease

4.1.2.2 Integrated hardware

Kiwi Power's DERMS platform has a fully in-house designed, integrated hardware processing station (Fruit) specifically designed for DER management, battery management and other smart energy applications. Rather than deploying or modifying third-party hardware as is common among other DERMS platforms, the Fruit ensures that Kiwi's platform operates as a fully integrated end-to-end solution, allowing easy setup, monitoring and troubleshooting.

The Fruit is rigorously engineered to provide fast, reliable and effective operation either as a stand-alone Core or in conjunction with a range of modular expansion segments (eg. metering segment, analogue control segment). The Fruit is developed around the secure Electric Imp platform and is accredited to the highest cybersecurity certification currently available for IoT devices (UL 2900-2-2). A copy of the Fruit datasheet is available in Appendix A.

4.2 Overview of Opus One solution

The GridOS Optimization Engine (OE) performs three-phase unbalanced time-series optimization on distribution and sub-transmission networks. It is the analytics backbone of the following GridOS product lines:

- GridOS DERMS
- GridOS Transactive Energy
- GridOS Integrated Distribution Planning

4.2.1 Objective functions

The OE solves for various optimization objectives which are shown in the table below:

Optimization Objectives	Description
Peak Shaving	Minimize peak load at substation
Loss Minimization	Reduce system losses over time period
Cost Minimization	Minimize cost to operate the network
Conservation Voltage Reduction	Reduce system voltage to reduce energy consumption
Voltage Optimization	Flatten voltage band

To meet these objectives, the OE will dispatch available network assets.

4.2.2 Network assets

The OE models the following shunt-based assets:

1. Inverter-Based Energy Storage

2. Solar Photovoltaic (PV)
3. Electric Vehicle
4. Wind Turbine
5. Shunt Capacitor
6. ZIP loads and demand response
7. Synchronous Machines

It also models the following link-based devices:

1. Voltage Transformers
2. Voltage Regulators
3. Overhead lines
4. Underground lines
5. Switches, Breakers, Fuses

Network assets can be configured to either be in scheduled, local, or global mode. In scheduled mode, devices will follow either a power schedule, ON/OFF schedule (e.g. switches and capacitors), or tap schedule (e.g. voltage regulators). In local mode, devices will behave based on local intelligence (e.g. OE can model PVs running with droop control). Assets in global mode will be dispatched by the OE to achieve the objective function.

4.2.3 Network reliability

When running an optimization, the OE will ensure that the dispatch schedules of controllable devices do not compromise the reliability of the grid. More specifically, while performing an optimization, the OE will ensure that:

- All device ratings are respected (e.g. no over-current or over-power violations on lines and transformers)
- All voltages at every node and phase are within system limits

4.2.4 Time-series analysis

The OE can run time-series analysis at various intervals (e.g. 1 hour, 15 minutes, 5 minutes) and at irregular intervals.

4.2.5 Inputs/Outputs

In general, the inputs required by the OE are the network model, load and generation forecasts and schedules of assets in scheduled mode.

OE requires the network model to be in Common Information Model (CIM) format. CIM is an IEC standard (61968 and 61970) and is designed to be interchanged between many systems. CIM is used in GridOS OE because it is an industry standard and allows our product to better integrate with the existing ecosystem of power system tools. Currently the OE uses a combination of CIM16 and CIM17.

Outputs of the OE include complete network state at each timepoint (e.g. voltages at every node, current and power through every line and transformer), and optimal dispatch schedule of devices. Output of the OE also conforms to CIM standards.

4.2.6 Energy Markets and Distribution Locational Marginal Pricing

The optimization engine calculates distribution locational marginal prices (DLMP) for energy markets. This is used for day-ahead and same-day energy markets. The DLMP is broken down into energy, loss, and congestion components, and is computed at every distributed energy resource node in the network.

4.3 Overview of Lakeland Power systems

Any solution attempting to address local grid constraints through situational awareness whilst responding to bulk system requests will require information and data from the local distribution operator. In Ontario, Canada, this will typically be provided by the LDC[11]. At a high level, the information can be grouped into two categories:

Network information - As described in the Overview of Opus One solution section above, the network model is required for network optimisation purposes. It is used to forecast any network constraints that might be introduced as a result of certain actions and determine which assets and facilities are best placed to respond to a bulk system request.

Measurement data - Measurement, or metering data, is required for network optimisation and for provision to the system operator as evidence of asset

[11] In the UK this is the Distribution Network Operator (DNO)

performance. It is also often used for calculating how any revenue, savings or charges might be shared between participants. Each use case is likely to require measurement data at different intervals and frequencies. For example, network optimisation might need real time metering whilst system operator reporting might be monthly.

Lakeland Power uses a number of systems that capture and store the data described above. Their applicability to the project will be subject to the IESO market data requirements, the accessibility of the data and other considerations such as communication protocols and security.

The Lakeland Power systems and service providers that will be considered during the design of the solution:

Survalent - Lakeland Power employs their Advanced Distribution Management System (ADMS) as their fully integrated supervisory control and data acquisition (SCADA), outage management system (OMS), and distribution management system (DMS) solution that runs on a single, easy-to-use graphical interface. Built on a Windows-based platform that is scalable, secure, and open, it efficiently integrates, manages, and processes data from a broad array of sources. It offers a number of interfaces and protocols as standard.

Utilismart - One of two metering platforms employed by Lakeland Power. Utilismart provides the metering summary of commercial and industrial meters that are >50KW. Utilismart platform is a secure, cloud-based meter data management and services. Utilismart gathers data and sends it directly to Lakeland Power for billing. For >50kW customers the IESO only sees wholesale meters on the network, not each individual customer meter, and bills Lakeland Power off of the wholesale meter.

Olameter - The second metering platform employed by Lakeland Power. Olameter provides the metering summary of all residential and commercial meters that are <50KW. It gathers data from the meters on time-of-use pricing through its own software and sends this to the IESO meter data management system (MDMR). It also sends the same data to Savage Data Systems (see below). Olameter's vendor diagnostic advanced metering infrastructure (AMI) Data Platform is a secure web application that stores, analyzes, and reports on this information. It can import meter data in CMEP, XML, HHF, MV-RS, and basic CSV formats from multiple vendors at once. Whether they originate from the utilities' own systems or from systems hosted externally. Olameter supports all of these systems at a low cost on a Software-as-a-Service (SaaS) basis.

Savage Data Systems - Aggregate all meter data from Olameter and have a live link to Survalent for SCADA. Further to this, they also provide a backup source for IESO reporting. They are based locally in Ontario and their systems are very customisable. They may be the best option for integration, but they do not have access to Utilismart meter data.

4.4 Combined solution and interoperability

The combined solution and interoperability between the systems is not within the scope of this document. The market research and analysis required to produce this report has also informed the solution design which has been running in parallel. The outcomes from the solution design will inform the following project documents in turn:

- 1.2 Use Cases Definition Document
- 1.3 User Requirements Definition Document
- 1.4 Solution Architecture Diagram
- 1.5 Joint Product Specification Document

5 Forward Plan

Our forward plan focuses on the implementation of the project itself. It is informed by the policy, regulation, market and technology sections of this report. We set out the resources available to participate in the markets identified. We explain our reasoning for the market selected for participation and we set out the outcomes we both anticipate and desire from the project. It is based on the information known at the time writing and is subject to change as the project progresses.

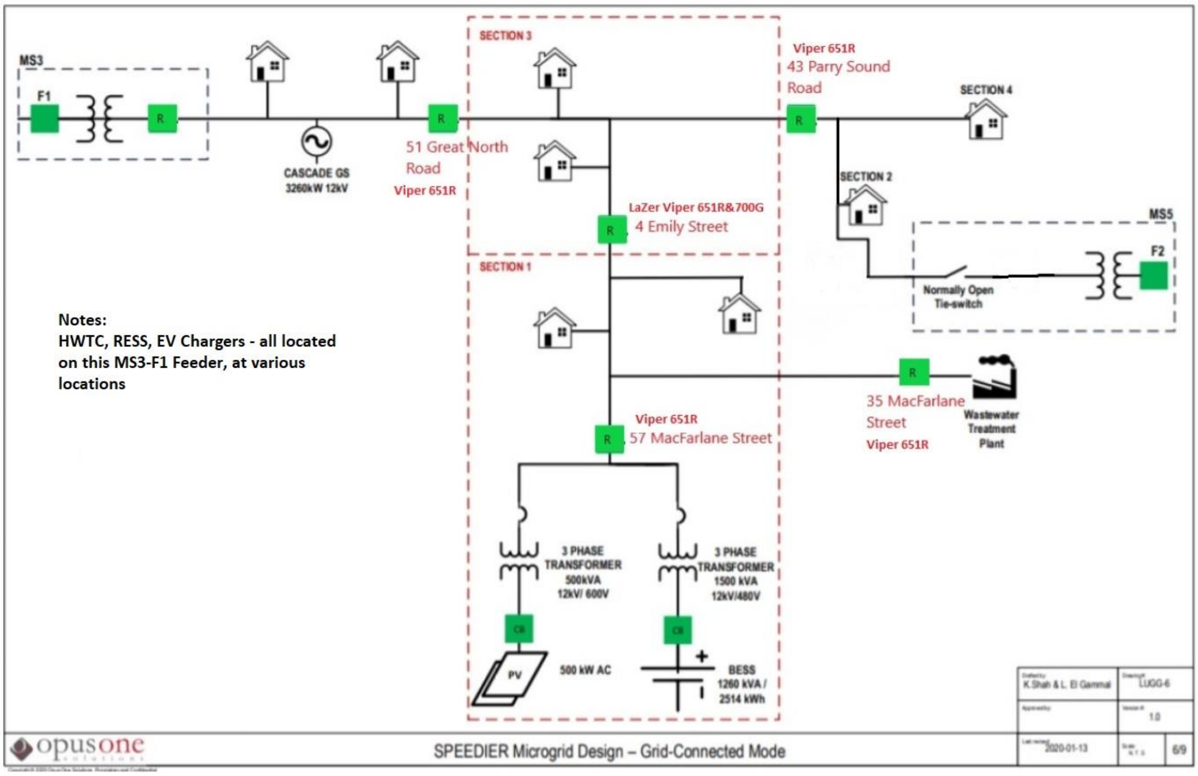
5.1 Participating resources

The biggest factor that influences our market selection decision is the suitability of Bracebridge Generation's suite of flexibility resources for each market. These assets are either owned by Bracebridge Generation or operate on the Lakeland Power network. There is little to no value in participating in a market where the entry criteria prevent their assets from participating.

Appendix B lists a variety of resources types earmarked for potential participation in the project. They are either existing resources or they will be commissioned during the project period. These include:

- Distribution network connected battery storage
- Distribution network connected renewable generation
- Commercial and industrial generation
- Commercial and industrial load
- Residential battery storage
- Residential load

All the resources are, or will be, connected to the Lakeland distribution network and are therefore embedded. They are connected to a single feeder (MS3) set out in the single line diagram below. It is also worth noting that a microgrid will also be established at the "LaZer Viper" reclosure located at 4 Emily Street.



A guiding project principle is to have as many of the resources listed participate in the markets selected as possible. All available resources are capable of reducing or shifting load in certain configurations. Given the capacity of the resources, how we choose to aggregate the resources will be an important decision in enabling participation to ensure we meet minimum capacity entry criteria.

5.2 Ontario market selection

Taking the policy, regulation, market entry criteria, and available resources into consideration, the project participants have concluded that we will simulate participation in the Ontario Capacity Auction during the project. The reasons for this decision are set out in the table below.

Existing markets

Existing Ontario Market	Conclusion	Participate
Real-time Energy Market	At this stage, it has been assumed that, with the exception of possibly the BESS, our available resources are not suitable for this market due to their limited capacity. Neither are residential resources able to participate.	No
Demand Response Auction (DRA)	Appears to allow the majority of our available resources to participate, but the last auction was in Dec 2019. It will be replaced by the Capacity Auction in Apr 2020. We would be	No

	unable to participate in the market during the project or beyond.	
Industrial Conservation Initiative (ICI)	The minimum 500 kW threshold is appealing, but this market is only open to C&I and not residential customers. The BESS and other assets would need to be linked to a Class A customer. Distributed asset aggregation and optimisation would prove difficult in this project scenario.	No
Real-Time Operating Reserve	The response times are achievable, but only dispatchable loads and generators may participate. With the exception of the BESS, none of our resources can be classed as dispatchable. Also, operating reserve can only be offered if participating in the real-time energy market.	No
Ancillary Service Market	Of the four ancillary services procured by the IESO, the regulation service is of most interest to project participants given the global growth in battery storage. Not suited for project participation given that only the BESS is likely to be able to do so. Neither is it known when the next tender will be held. The drivers behind the increased need for regulation service will be reviewed (see the IESO Operability Assessment Summary)	No

Market engagements

Future Ontario Market	Conclusion	Participate
Capacity Auction	Appears to allow the majority of our available resources to participate. Even more so than the DRA. The first auction is in Jun 2020 and we could consider bidding[12]. However, the commitment periods fall outside the project timeframe so we would need to simulate the market. It also provides a path to commercialisation beyond the project.	Yes
Economic Demand Response	This is not a market as such, but rather a change to the payment mechanisms for demand response. Given the final decision is not made until Jun 2020 this will not be considered as part of the solution design. However, it may influence the modelling of project and commercial benefits and it will be considered once the IESO decision has been made.	No
Energy Storage Advisory Group	Again, this is not a market, but a working group in this instance. Given the global growth in battery storage resources and their involvement in this project, the output from the working group will be monitored throughout in the event that it influences post project commercialisation decisions.	No
Improving Accessibility of Operating Reserve	The proposed solutions to the problem of inaccessible OR appear to be related to amendments to the market rules and the claw-back of OR payments. The amendments focus on incremental energy provided during activation and do not appear to have any material impact on this project or beyond.	No

[12] Due to COVID-19 this has been postponed to Q4 2020. At the time of writing no specific auction date has been published.

As expected, the resources available were the most significant factor in our market selection. Especially given our desire for as many of the available resources to participate as possible. Whilst the individual solutions had little influence at all, the time available to integrate our technology solutions was the second factor. Given time, our combined experience and technical capabilities allow us to participate in any of the markets considered in this document. For example, the Kiwi Power solution actively serves the global equivalents of all the UK and Ontario markets.

It is also worth noting that whilst we have ruled out participation in a number of markets for this project, they will all be considered for participation beyond the project.

5.3 Alberta market selection

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

5.4 Participation in the Ontario Capacity Auction

Due to the misalignment between the Capacity Auction and the project timelines we will be unable to fully participate in the Capacity Auction during the project. Instead the project will aim to replicate actual market behaviour as closely as possible through simulation. We also intend to test and validate various what-if scenarios. To achieve this, the market rules and obligations must be understood by the project team.

The IESO Capacity Auction training guide breaks participation in the Capacity Auction into four stages:

1. Pre-Auction Requirements
2. Auction Process
3. Forward Period Activities
4. Commitment Period Activities

It is only at the fourth stage of participation where the balancing of system and local needs is relevant. Therefore it is the fourth stage that is of particular interest to the project team as this is where the technology solution and innovation is focused. It will also be the main focus for the simulation since it is not possible to simulate the preceding stages without entering the market. This section describes the resource types that can participate in the market and provides a high level summary of stages one to three in preparation for future participation. More detail is provided for stage four, setting out the rules that must be considered from a technical perspective. Meanwhile, the IESO training guides and related documentation will continue to be the primary references for design purposes and the IESO will be called upon for guidance where necessary.

IMPORTANT: All times in this section are EST. IESO markets operate on Eastern Standard Time (EST) all year round and do not change for Daylight Savings Time.

5.4.1 Demand Response and Generation Resources

Demand response resources must be able to reduce their energy withdrawal from the grid. The Capacity Auction has two demand response resource types which are defined by the speed they are able to respond to an activation notice:

Demand response resource	Response time
Dispatchable Load	Can respond to a 5 minute dispatch instruction
Hourly Demand Response (HDR)	Cannot respond to a 5 minute dispatch instruction

Unlike the Demand Response Auction, generation resources can also participate in the Capacity Auction. Therefore, resources can be categorised into three different groups depending on whether they can reduce energy withdrawal or increase energy production:

Physical demand response resources - Are those that are revenue-metered by the IESO and fully participate in the energy market (e.g. a dispatchable load).

Capacity generation resources - Must be revenue-metered and participate in the energy market. Therefore, all generators are physical resources and must be dispatchable. They must also be non-committed (ie. not under contract with the IESO or OEFC).

Virtual demand response resources - Are not revenue-metered by the IESO. They are typically Hourly Demand Response (HDR) resources (e.g. an aggregator with residential customers as contributors) or non-dispatchable loads that act as a contributor to an HDR resource.

Multiple resources can be allocated to a capacity obligation, at which point they are considered contributors to the obligation. The project team will need to decide how and in what manner the available resources will participate.

At this stage in the project, the intention is to participate as virtual demand response resources. Whilst some project resources are able to respond to a 5-minute dispatch instruction, we have ruled out participating as a dispatchable load (DL) due to the following reasons:

a. Once it becomes dispatchable, bids must be submitted to buy energy – energy cannot simply be withdrawn from the grid as needed.
b. The load must be capable of receiving and responding to dispatch instructions from the IESO 24 hours a day, 365 days a year.
c. There are potential severe penalties for not following the dispatch instructions.
d. The dispatchable load must be revenue metered by the IESO which is costly and time consuming to install.
e. The project does not plan to offer operating reserve, which is one of two primary reasons to become dispatchable.
f. Market rules do not allow a load resource to participate as a Dispatchable Load (DL) and as a contributor to an HDR portfolio simultaneously.
g. Choosing to register as a dispatchable load requires additional upfront costs and ongoing effort. This includes:
    i. Arranging for required access to systems within the IESO Portal
    ii. Setting up a dispatch workstation to receive web-based dispatch instructions
    iii. Updating metering and telemetry, if required
    iv. Taking additional training

We have ruled out participating as capacity generation for similar reasons and also because of the limited number of potential resources that can offer generation. The information that follows in this section focuses on the rules relating to HDR. Information relating to dispatchable loads and capacity generation is included where it is considered important or relevant.

5.4.2 Pre-Auction Requirements

The IESO publishes a pre-auction report at least two months in advance of the auction. It provides the following information:

- Authorization requirements
- Demand curve elements such as:
  - Target capacity
  - Reference price
  - Maximum auction clearing price
- The auction deposit required
- Auction timelines and deadlines

At the time of writing, the first Capacity Auction has not yet occurred but the demand curve elements provided in the last pre-auction report for the Demand Response Auction in Dec 2019 can be found in Appendix C.

The following tasks must be performed before the auction begins:

- Register as an organisation with the IESO, if not already registered
- Authorise as a Capacity Auction Participant (CAP)
- Submit the Capacity Auction deposit
- Qualify capacity (the minimum requirement is 1 MW)

It is important to note that in addition to the 1 MW capacity minimum limit, the Capacity Auction is acquiring a four-hour product. Resources are expected to be available for four hour blocks of time, though a dispatch could be for 1, 2, 3, or 4 hours.

A key decision for future participation in the market will be which organisation, Lakeland Power Distribution or Bracebridge Generation, will become an authorised CAP. This will influence a number of activities, notably the contracting party for flexibility providers and resource owners. It will also influence benefit cost analysis (BCA) activities. The IESO has confirmed that a Local Distribution Company (LDC) may participate.

The following information must be submitted to the IESO for capacity qualification:

- The amount of capacity to be provided

- The obligation period for which offers will be submitted
- The resource type (generation resource or demand response resource)
- An attestation for any generation resources
- The zonal location of resources for which offers will be submitted
- Whether or not the resources are revenue metered by the IESO
- Confirmation of auction deposit submission

Obligation periods are seasonal:

- Summer - May to Oct
- Winter - Nov to Apr

The IESO Zonal Map is used in support of the IESO Demand Response Programs .A description of the IESO Zonal Map can be found under the Demand Response Auction (DRA) section of this document. Bracebridge and the Town of Parry Sound are in the ESSA zone. The current IESO description for this Zone is “The total resources are much less than the zone peak demand”.

5.4.3 Auction Process

The date and time of the capacity auction window is published in the pre-auction report. The auction lasts for approximately two days. During this window, CAPs submit offers limited to the type and amount of auction capacity that was qualified during the pre-auction period for each zone and obligation period.

The key auction characteristics that must be considered by the project are:

- Offers are submitted for each of the summer and winter obligation periods, and apply for the entire obligation period.
- We can participate in one or both obligation periods. Separate offers must be submitted for each obligation period.
- Submitted offers are for any quantity between 1 MW and the capacity qualified in the Pre-Auction Process (to one decimal place).
- If successful in the auction, a separate capacity obligation is received for each obligation period.
- IESO public reports provide a list of successful CAPs that received a capacity obligation, their respective capacity obligations and clearing price for each zone.

- IESO confidential reports are issued to individual CAPs and provide the capacity obligation and type for each zone.

If we do not clear the auction we remain registered as a CAP but our deposit will be returned on request. The results from the Demand Response Auction in Dec 2019 can be found in Appendix C[13].

5.4.3 Forward Period Activities

The forward period starts after the auction has ended up to the start of the first obligation period a participant must make their capacity available. All CAPs that are successful in the auction must carry out the following activities to satisfy their capacity obligations:

- Authorise as a Capacity Market Participant (CMP)
- Allocate physical resources to a capacity obligation
- Post prudential support (guarantee or irrevocable commercial letter of credit)
- Register/Update virtual resources
- Allocate virtual demand response resources to obligation

To benefit from the two separate baseline methodologies a CMP has the opportunity to split the capacity obligation in two, between a C&I and a residential resource, when allocating virtual demand responses resources.

Virtual demand responses allocation is performed using the Contributor Management tool and can continue to be done monthly during the obligation period. Whilst changing contributors can be done monthly there is typically a 3 month process to do so. If contributor information is not submitted before the start of the month by the required deadline participation in the energy market is not allowed.

5.4.4 Commitment Period Activities

The commitment period runs for a year and includes both summer and winter obligation periods. Participation in the energy market involves the following primary main activities.

- Submitting energy bids and other dispatch data
- Responding to dispatch instructions (including test activations)

[13] Whilst different to the Capacity Auction, the Demand Response Auction results from the last year give the best indication of the volumes and prices that might be achieved.

- Submitting outage requests if required
- Provision of measurement (meter) data

To optimise for local network demands and bulk system requests the project team will need to consider these activities and the related rules and procedures.

5.4.4.1 Submitting dispatch data

CMPs using Dispatchable Loads or HDRs must submit a daily energy bid in the day-ahead commitment process. Bids should reflect a CMP's capability. An energy bid is:

> the $100/MWh bid price threshold
< the $2,000/MWh Maximum Market Clearing Price (MMCP)

CMPs must also submit ramp up and ramp down values for each HDR resource that is equal to the capacity of the HDR resource.

CMPs are expected to submit dispatch data for all hours of the availability window for their capacity obligation. The availability windows are:

- Summer (May to Oct): Business Days, 12:00 to 21:00 EST
- Winter (Nov to Apr): Business Days, 16:00 to 21:00 EST

The deadline for submission of dispatch data in the DACP is 10:00 EST the day ahead. This allows time for the day-ahead commitment engine (DACE) to process all bids. The DACE co-optimises energy and operating reserves over the 24 hours of the next day to determine commitments and schedules to meet the next day's expected demand.

A standing bid may be submitted for a bid that is expected to be the same from day to day, or week to week. Allowing it to be submitted only once thus decreasing the time spent on submissions and ensuring that there is always a bid in the market. Standing bids are converted to daily bids once a day, at 06:00 on the pre-dispatch day. A standing bid only takes effect after it has been converted to a daily bid. A revised bid is then needed to change this. Bids can be revised or removed up until 09:00 on dispatch day.

The IESO provides an API for dispatch data provision. The details of which can be found on the IESO website - Market Participant Submissions (incl. MIM, EMI & API).

Capacity Generation Resources

Capacity generation resources are treated differently to dispatchable loads and HDR resources. Offers are submitted at least equal to the capacity obligation day ahead for every hour of the availability window. During pre-dispatch, the IESO checks that offers have been maintained subject to the most restrictive of the following parameters:

- Generator's Elapsed Time to Dispatch;
- Minimum Generation Block Down Time; and
- 2-hour Mandatory Window.

Like dispatchable loads, generation resources are committed, scheduled, and dispatched on a five-minute interval using the existing day-ahead and real-time scheduling process.

5.4.4.2 Responding to dispatch instructions

Pre-dispatch schedule

The DACP runs from 10:00-15:00 and the results are then passed to the pre-dispatch engine. The results from the first pre-dispatch run are published at 15:07 and show the capacity and hours that could be needed for the next day. Pre-dispatch continues to run hourly and results are published after each run in the form of a pre-dispatch schedule. Pre-dispatch runs between 15:07 and 23:07 publish data for the remaining hours of the current day and all hours of the next day. They continue into the next day until 09:07 before DACP runs again.

Pre-dispatch schedules are an indication of what might be scheduled in real-time and are non-binding. It is not until an activation report is issued at least 2 hours prior to dispatch that the actual capacity and hour required for HDR resources will be known.

A sample pre-dispatch schedule is shown below:

Type/Tag	C/U	Scheduled MW for Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Energy	C													-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0			
	U																								
Energy	C													-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4			
	U																								

Standby reports

The standby report notifies participants with HDR that they may receive an activation on the dispatch day. HDR participants should monitor for a standby notice from 15:00 day ahead until 07:00 on the dispatch day.

Standby notifications will be issued for a resource when one of the conditions are met:

- The pre-dispatch shadow price is equal to or greater than $100/MWh for at least 1 hour during the availability window prior to 07:00 of the dispatch day.
- When a participant has a pre-dispatch schedule less then the maximum bid quantity for any hour during the availability window.

If the standby notice is received by 07:00 on the dispatch day, the HDR resource is required to be available to reduce its energy withdrawal during the availability window the same day. Bids can be removed by 09:00 without penalty if a standby notice is not received on a given dispatch day. If bids are not removed there remains a chance of activation.

A sample standby report is shown below:

Demand Response Standby Report

For MP1
Created at Feb 10, 2016 06:45:00
For Dispatch Day Feb 10, 2016

Resource Name	Standby Notice Issued
RESOURCE_1	Yes
RESOURCE_2	Yes

Activation reports

Activation reports are issued:

- When the pre-dispatch schedule is less than the resource's total bid quantity for 1 up to 4 consecutive hours of the availability window on the dispatch day.
- At least 2 hours before the start of the first dispatch hour to which it relates.

Participants should start monitoring for activation notices from 09:00 and can stop monitoring at 15:00. There is no requirement to remove bids if an activation notice is not received.

Demand Response Activation Report

ieso
Connecting Today.
Powering Tomorrow.

For MP1
Created at Feb 10, 2016 12:30:00
For Feb 10, 2016

Resource Name		Scheduled MW for Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
RESOURCE_2	Energy Bid (MW)													15	15	15	15								
	Energy Schedule (MW)													10	9	8	7								
	DR Curtailment (MW)													5	6	7	8								
RESOURCE_1	Energy Bid (MW)															20	20	20	20						
	Energy Schedule (MW)															10	9	8	7						
	DR Curtailment (MW)															10	11	12	13						

Accessing reports

Pre-dispatch schedules, standby and activation reports can be accessed by going to the IESO Reports Page and logging in to the confidential participants report area. The IESO also provides an API for report access. The details of which can be found on the IESO website - Access Interfaces for Confidential Reports.

Test activations

Two test activations may be scheduled during each obligation period for all resources with a capacity obligation. The tests are scheduled during the applicable availability window. During the test, resources are expected to demonstrate a reduction in energy withdrawal or increase in energy production equal to the capacity bid or offered. Tests require four consecutive hours of response.

Failure to perform a successful test activation may result in one or more of the following:

- Non-performance charges;
- A subsequent test activation; and/or
- A compliance investigation.

Timeline summary

Appendix D provides a summary of the timeline described above. Optimisation for local network and bulk system balancing will need to account for this schedule. Other factors such as battery state of charge management will also need to be considered.

5.4.4.2 Submitting outage requests

CMPs with hourly demand response resources are required to inform the IESO of non-performance events as per market rules set out in the outage management process.

If HDR resources need to increase or decrease capacity at any time after the start of the mandatory window (2 hours prior until 10 minutes prior to the start of the dispatch hour) the following steps must be followed:

1. Contact the control room for IESO approval
2. One of the following reasons must be included:
    - Equipment malfunction;
    - Worker or public safety situation;
    - Legal requirement;
    - Property damage;
    - Environmental regulations; or
    - Change due to a non-performance event.
3. Once approved, bids must be updated

Dispatchable loads and capacity generation resources must submit outages as per market rules set out in the outage management process.

5.4.4.3 Provision of measurement data and baselining

Market participants are required to submit metering data, referred to as measurement data, for settlement purposes. It enables the IESO to generate resource specific baselines and to validate dispatch performance against that baseline.

The IESO requires that facilities are either IESO or LDC revenue metered, which must be Measurement Canada approved. Measurement data can be collected directly from the meter by the IESO or provided to the CMP by their LDC respectively. Resources that are LDC revenue metered can only participate as HDR resources. Resources that are revenue metered by the IESO but are contributing to an HDR obligation are known as non-dispatchable loads.

For HDR resources there are separate requirements depending on whether they are C&I or residential resources.

Commercial, Industrial and Institutional HDR

Participants were initially required to submit five-minute interval measurement data on a monthly basis (a single one month CSV data file per virtual meter point ID). However, following consultation with the DRWG, this was changed in Jun 2020. Participants now only submit measurement data for months where an activation has occurred.

In addition, they must also submit an additional two months of historical measurement data (a single three month data file per virtual meter point ID) for the following two conditions:

a. At the beginning of the first commitment period
b. Removal or additions of virtual contributor(s)

Residential HDR

Demand response market participants are required to submit aggregated hourly (60-minute interval) measurement data only for days in which they received demand response activations during the commitment month.

Measurement data (single data file per virtual meter point ID for all activation days) must be submitted for each of the two groups of contributors:

- Treatment group
- Control group

HDR Baselining

HDR baselines are required to determine settlements for each HDR resource and in the assessment of capacity charges and dispatch charges. A baseline is an approximation of a resource's consumption profile that is used to estimate what the resource would have been consuming had an activation not taken place. For C&I HDR resources, it is calculated by using the measurement data from a historical period that meet the criteria of suitable business days. For residential HDRs, baselines are determined using measurement data from a set of residential contributors pre-selected as part of the control group.

Error handling

The IESO will notify participants of any errors with the data and participants have two days from the date of the notification to correct and resubmit a revised measurement data file.

Audit requirements

Participants must retain individual contributor measurement data and supporting registration documentation, including agreements with their respective contributor(s), for audit purposes.

For physical demand response auction participants, dispatchable loads or capacity generation, there are no specific requirements because the IESO will gather the required data via their own revenue meter.

Measurement data submission

Measurement data can be submitted via Online IESO or an API. The API instructions can be found on the IESO website - Access Interfaces for Confidential Reports.

File format requirements for measurement data submissions can be found in Appendix E alongside the metering information that must be submitted as part of contributor management.

Project considerations

Metering data is not only required for IESO reporting purposes. In aggregated asset or portfolio type scenarios, it can also be used to distribute revenue, and sometimes penalties, between resource owners based on their contribution to an obligation. This is subject to the business model and contractual relationships with contributors, but it is an additional factor to consider when making decisions relating to the metering framework adopted by the project.

Key project decisions relating to metering will include:

1. What is the optimal location for the meter(s)?

Viable options	IESO considerations
Place a meter in front of all participating assets	Only a single resource needs to be registered with the IESO. Provides greater flexibility for behind the meter optimisation.
Each resource is individually metered	Each participating resource would need to be individually registered with the IESO. Offers little flexibility for local network optimisation.
A mixture of the above options	Could group resources based on location or by type. Provides greater flexibility for behind the meter optimisation.

2. How will the measurement data be sourced?
3. What type of meter(s) would we use for the project?

Inputs into these decisions might include:

- What are the current and planned metering installations for new and existing assets?
- What systems are currently being used to gather and collect LDC measurement data and do they offer an API?
- What agreements would need to be in place to gather and share measurement data with third parties such as Opus One, Kiwi and the IESO?
- Will we actually dispatch assets given we are simulating participation in the market?
- What are the IESO and LDC revenue metering costs and installation timelines?
- Is there an alternative metering solution that can be used for simulation purposes?

When registering a resource against an obligation the following metering information is also required for virtual demand response resources:

- Specify if data is collected directly from the meter via remote interrogation, or provided to the participant by their LDC.
- Upload a Record of Installation (ROI) for each LDC meter installation associated with a site.
- Provide a Single line diagram (SLD) when more than one LDC metering installation is associated with a site, or when the demand response type is behind-the-meter generation.

Individual contributor meter data and supporting registration documentation must also be retained for audit purposes by the IESO.

5.4.4.5 Availability Payments

HDR resources are paid an availability payment[14] for each hour they are available during the availability window. They do not receive an activation payment except in the following two instances:

Test Activations – Fixed payments of $250/MWh curtailed are applied
Emergency Operating State Control Action (EOSCA) Activations – Payments are based on a participant's (Bid-HOEP) x number of hours curtailed

[14] The payment calculation is included in the IESO Capacity Auction Training Guide

Dispatchable loads and capacity generation resources get paid for activation based on the energy delivered. Therefore, if they were to bid/offer more than their obligation and are subsequently activated for that amount they would be paid for all the energy delivered.

5.4.4.6 Payment and Non Performance Charges

Market participants are settled using the physical markets settlement process, for both payments and non-performance charges.

Non-performance charges result from a failure to satisfy capacity obligations. They are intended to incentivise compliance, ensure integrity of the electricity market and avoid the IESO paying for the capacity that has not been provided. Payment and charges are assessed and calculated for each resource registered by the market participant to fulfill the capacity obligation. There are four types of charges that may apply:

- Capacity charge - Failing to deliver capacity in the energy market
- Availability charge - Availability requirements are not met
- Administration charge - Measurement data not received by the IESO
- Dispatch charge - Dispatch instructions were not followed

In addition to the charges described, non-performance may be flagged for compliance assessment and may result in IESO sanctions.

Understanding of these non-performance charges and the associated risk will inform the joint product solution design as well as the operational processes. Simulating different scenarios and calculating the expected charges is a worthwhile exercise to determine business and economic risks.

Appendix F provides further description of non-performance charges as well as the equations used to calculate them.

5.4.4.7 Simulation

The project intent is to simulate the commitment period activities for the Capacity Auction as closely as possible. This will ensure we build and test a joint solution that is ready to enter the market with minimal additional effort and allow us a smooth transition to commercialisation. Understanding the market rules will also help develop operational processes and perform economic analysis that will inform how we enter into the market.

How the project simulates the market will have to be considered. Given the Capacity Auction is a new market, there is no historical data on which to base the simulation on. However, the data from the Demand Response Auction, that the Capacity Auction replaces, is publicly available on the IESO website.

We do know that there have not been any economic activations in the Demand Response Auction for a number of years so we will need to decide whether we limit activations to test activations only or model and test a variety of economic and emergency scenarios.

We will also need to decide which commitment period we model. Due to project timelines we will be unable to model an entire season since Summer runs from May to October and Winter from November to April.

5.5 Participation in an Alberta market

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

5.6 Expected outcomes

The primary purpose of this report is to inform the solution design for the Ontario Capacity Auction. It sets out the market rules that must be adhered to and the interfaces by which to interact with the market. It also describes the technology and the disparate systems that must come together to form the combined solution. Of course, the technical solution is not the sole consideration for participation in any market. Economic and operational factors also have a significant influence on decision making. This report is the first step towards informing those decisions and proving commercial viability of the solution.

The report should also serve as a reference for future reporting activity and beyond the project planning. Trade-offs will inevitably have to be made to fit with project timelines and there should be a clear path to active market participation and wider commercialisation of the combined solution. The Ontario Capacity Auction timeline does not allow active participation during the project period but any market simulation should replicate actual market behaviour as closely as possible. The opportunity to bid in the first auction sometime in 2020 must be risk assessed, an operational framework established, and the appropriate preparations made.

At the same time, future market participation should not be limited to the Ontario Capacity Auction. The project should demonstrate wider applicability and demand for the combined solution in other markets in Ontario and other jurisdictions. Only by understanding the wider policy and regulatory landscape as well as market developments and engagements can the market opportunities be fully assessed and the appropriate direction taken.

An update on this section including the choice of the alternative second market will be provided as part of the M3 deliverables.

Appendices

Appendix A - Fruit datasheet summary

The Fruit is an innovative and low-cost Processing Station designed for Demand Response and Battery Management, with numerous additional uses within the Smart Energy space. The Fruit provides a wide range of metering and control functions, and is integrated with the Kiwi Operations Management Platform to allow easy set-up and monitoring whatever your application.

Built on Kiwi's long experience of Internet- of-Things solutions, the Fruit is rigorously engineered to provide fast, reliable and effective operation either as a stand-alone Core or in conjunction with a range of expansion Segments.

- Cost effective solution - designed to reduce total cost of ownership
- Flexible - deploy only the functionality needed
- Easy to install - pre-configured modules to minimise on-site works

Product Range	
Fruit Core	for cloud communications, local processing, Ethernet, legacy pulse meter and serial interfacing and dual-relay connection
3-Phase Metering Segment	for measurement of voltage, current (via CTs), line frequency, active and reactive power across up to three phases
Analogue Segment (coming soon)	for interfacing with 4-20mA, 0-20mA and 0-10V inputs and outputs
Accessories: Industrial 2G/3G/4G router, DIN-mounted PSU, cabling, connectors and IP-rated enclosure	

Typical Applications
Enabling centrally-dispatched Demand Response programmes such as STOR, Capacity Market and Effacement
Battery Energy Storage control (full EMS)
Enabling both static and dynamic Frequency Response programmes, such as FCR, FFR and EFR
Monitoring and control of generation assets
Integration with Building Management, SCADA and PLC systems
Environmental monitoring
Metering and submetering of electrical installations

DNO constraint management
Remote Telecoms Unit (RTU) for TSO integration

Features
Highly integrated Internet-of-Things node developed around the revolutionary Electric Imp platform
Dual-band WiFi
Cloud and local Ethernet ports
Secure, failsafe OTA application and OS updates
Flexible interfacing options including GPIO, RS232, RS485, Modbus/TCP and relay terminals
Clear front-panel status and diagnostic indicator
Easy to install DIN-rail compatible form factor
Pluggable terminal blocks for ease of wiring
Expansion Segments connect via convenient DIN-rail bus
Integrated with KiWi's cloud-based time-series datastore, for highly scalable real-time data capture
Managed, tamper-proof configuration
Combined digital status and pulse-counting inputs

Standards Compatibility
DIN-EN 60715 TH 35 mounting
CE approval
802.11 a/b/g/n WiFi
Modbus/TCP and Modbus/RTU support

Physical	
Parameter	Value
Flammability class according to UL 94	V0
Mounting	DIN-EN 60715 TH35
Operating temperature (recommended)	0-50°C

Computational	
Application processor	32-bit ARM Cortex R4 with secure boot
Cache	32kB instruction & data
Application RAM	Over 1.2MB

Flash memory	16MB

Communications	
Maximum Cloud data rate	10 readings/input/s
RS232/RS485 data rate	Up to 1Mbaud
WiFi standards	802.11 a/b/g/n, dual-band 2.4Ghz & 5GHz
RX sensitivity (typical)	-97dBm (@1Mbps)
Ethernet	10/100MHz
Status LEDs	RGB Status, Red/Green BlinkUp™

Security	
WiFi standards	WPA, WPA2, WPS
Cloud data link encryption	TLS1.2-RSA-ECDHE (forward secrecy) Elliptic curve challenge- response
Managed silicon-to-cloud security stack	impSecure™

Performance	
Local data storage capacity without cloud access	Up to 1 year (configuration-dependent, average)
Centralised dispatch latency	< 1,000ms (communications-dependent)
Local frequency dispatch latency	< 100ms

Electrical					
Symbol	Parameter	Min	Typical	Max	Unit
V_{IN}	Supply voltage	12	24	24	V (DC)
I_{12}	Current consumption (at 12V)	-	330	500	mA
I_{24}	Current consumption (at 24V)	-	160	400	mA
f_{pulse}	Pulse measurement frequency	-	50	200	Hz
S_{max}	Maximum number of Segments	-	-	8	-
V_{rel}	Relay terminal voltage	-	5 (DC)	30 (DC) or 250 (AC)	V
I_{rel}	Relay terminal current	-	-	8 (DC) or 10 (AC)	A
P_{rel}	Relay switching power	-	-	4,000	VA

Appendix E - IESO HDR measurement requirements

This appendix summarises the HDR measurement requirements for the IESO Capacity Auction:

1) Metering information that must be submitted when allocating an HDR resource to an obligation as part of contributor management.
2) The file format requirements for measurement data submissions during the commitment period.

The IESO Market Manual 12.0, Capacity Auctions, Issue 7.0 provides full details of the measurement requirements for the IESO capacity auction and should be referred to for the technical design.

Meter information requirements for contributor management

- Specify if data is collected directly from the meter via remote interrogation, or provided to the participant by their LDC.
- Upload a Record of Installation (ROI) for each LDC meter installation associated with a site.
- Provide a Single line diagram (SLD) when more than one LDC metering installation is associated with a site, or when the demand response type is behind-the-meter generation.
- Retain individual contributor meter data and supporting registration documentation for audit purposes by the IESO.

File Format Requirements for Virtual C&I HDR resource(s)

- Must not include any measurement error corrections;
- Must not include any loss adjustments;
- Must be provided in the following format:
    - A CSV (comma separated values) file format compatible with the IESO's Meter Data Acquisition System, containing two channels of 5 minute engineering unit values (without any gaps or overlaps).
    - The CSV data file shall adhere to the following format (separated by commas) corresponding to each column name, as illustrated in Figure 6-2 below;
        - Row 1 (Main header): "DATE,TIME,CH1,CH2"

- Row 2 (Data intervals): “YYYY/MM/DD, HH:MM, ###.###,###.###”, where:
  - Date: “YYYY/MM/DD”, as in year/month/day
  - Time: “HH:MM”, hour: minutes in Eastern Standard Time (EST);
  - Channel 1: Summation of all virtual contributors’ energy withdrawn from the grid, in Numeric “###.###,” in kWh up to three decimal places;
  - Channel 2: Summation of all virtual contributors’ energy injected into the grid, in Numeric “###.###,” in kWh up to three decimal places; and
- The CSV data file must contain 288 rows of data per day, having a beginning time of 00:05 and an end time of 24:00.

File Format Requirements for Virtual Residential HDR resource(s)

- Must not include any measurement error corrections;
- Must not include any loss adjustments;
- Must be provided in the following format:
  - A CSV (comma separated values) file format containing two channels of 60 minute engineering unit values (without any gaps or overlaps);
  - The CSV data file shall adhere to the following format (separated by commas) corresponding to each column name, as illustrated in Figure 6-3 below;
    - Row 1 (Main header): “DATE,TIME,CH1,CH2”
    - Row 2 (Data intervals): “YYYY/MM/DD, HH:MM, ###.###,###.###”, where:
      - Date: “YYYY/MM/DD”, as in year/month/day
      - Time: “HH:MM”, hour:minutes in Eastern Standard Time (EST);
      - Channel 1: Summation of all virtual contributors’ withdrawn energy in kWh up to three decimal places, in numeric value “###.###”;
      - Channel 2: Shall remain zero (with respect to the exclusion of ‘net-metered’ customers under residential HDR);
  - The CSV data file must contain 24 rows of data per day, having a beginning time of 01:00 and an end time of 24:00.

Appendix F - Non-Performance Charges

The following table contains descriptions of each variable used within HDR non-performance charge equations.

Variable	Data Description	Description
CCO_k	Capacity Obligation (MW)	The capacity obligation amount for the obligation period and zone for capacity market participant ‘k’. The initial capacity obligation is acquired through a capacity auction and subject to being reduced via the buy-out process.
$CACP_h$	Hourly Capacity Auction Clearing Price	The capacity auction clearing price for the obligation period and zone divided by the hours of availability for the day
CNPF	Capacity Auction Non-Performance Factor	The non-performance factor as listed in Section 7.1 of Market Manual 12 that corresponds and applies to the month being settled.
$DREBQ_k$	Demand Response Energy Bid Quantity	The demand response energy bid quantity calculated for demand response market participant ‘k’ as the sum of the quantity of demand response capacity provided by all participating demand response resources.
DRSQty	Demand Response Scheduled Quantity	Calculated as (Total Bid Qty – Schedule) where ‘Total Bid Qty’ is the maximum quantity of the demand response energy bid and where ‘Schedule’ is the real-time constrained schedule quantity.

Whilst the table below shows the Capacity Auction Non-Performance Factors.

Month	Factor
January	2.0
February	2.0
March	1.5
April	1.0
May	1.0
June	1.5
July	2.0
August	2.0
September	1.5
October	1.0
November	1.0

December	1.5

Availability charges - The availability charge for the obligation is calculated on an hourly basis. If through daily bids resources are declared unavailable for any hour of the availability window an availability charge is applied for that day.

1315	Demand Response Capacity Obligation – Availability Charge	N/A	N/A	$\sum_h^n$ (-1) x Max(0, CCO_k - $DREBQ_h$) x $CACP_h$ x $CNPF_h$ Where 'h' is an hour within the hours of availability for the day. Where 'n' is the number of hours of availability for the day.	Daily

Dispatch charges - Applies only to C&I HDR resources when consumption is not reduced below the expected level during each 5-minute interval of the activation window. Failing one five minute interval results in failing the entire hour. If activated, missing measurement data submission also results in dispatch charges. Dispatch charges are applied alongside capacity charges.

1317	Demand Response Capacity Obligation – Dispatch Charge	N/A	N/A	(-1) x $DRSQty_h$ x $CACP_h$ x $CNPF_h$ Where 'h' is an hour in which the *hourly demand response* resource failed to follow its *dispatch* instruction.	Hourly

Capacity charge - Non-performance will result in a capacity charge equal to one month's availability payment. If through the daily bids resources are declared available but then fail to dispatch if activated an administration charge equal to one month's availability payment is applied. If activated, missing measurement data or contributor information submissions will also result in a capacity charge. Capacity charges are applied alongside dispatch charges.

Given the severity of the charge, some leeway is provided to account for variations in load. Participants need only meet 85% of their requirement based on an average over any four hour activation period.

1318	Demand Response Capacity Obligation – Capacity Charge	N/A	N/A	(-1) x Availability Payment$_m$ Where 'm' is the month that is being settled. Where 'Availability Payment' is the *settlement amount* as calculated for CT1314.	Monthly

Administration charge - Applies only to HDR resources. Failure to submit measurement data by the applicable deadline will result in an administration charge equal to one month's availability payment.

1316	Demand Response Capacity Obligation – Administration Charge	N/A	N/A	(-1) x Availability Payment$_m$ Where 'm'is the month that is being settled. Where 'Availability Payment' is the *settlement amount* calculated for CT1314.	Monthly

Appendix G - Resources

The following resources were used when writing this document:

Real-time Energy Market

IESO, Mar 2020, Real-time Energy Market [website]

IESO, Jul 2017, Overview of the IESO Administered Markets [pdf]

IESO, Feb 2014, Introduction to Ontario's Physical Markets [pdf]

IESO, Mar 2020, Registered Participants [website]

Demand Response Auction

IESO, Mar 2017, Market Manual 12: Demand Response Auction 6.0 [pdf]

IESO, May 2017, Introduction to the Demand Response Auction [pdf]

IESO, Nov 2019, Demand Response Auction: Pre-Auction Report (xml)

IESO, May 2020, Demand Response Auction: Post-Auction Report (xml)

Industrial Conservation Initiative

IESO, Mar 2020, Price Overview [website]

IESO, Mar 2020, What is Global Adjustment? [website]

IESO, Aug 2019, Industrial Conservation Initiative Backgrounder [pdf]

IESO, Aug 2019, Industrial Conservation Initiative FAQs for LDCs [pdf]

Operating Reserve

IESO, Mar 2020, Operating Reserve Markets [website]

IESO, Oct 2011, Guide to Operating Reserve [pdf]

IESO Engagement

IESO, Mar 2020, Active Engagements [website]

Capacity Auction

IESO, Dec 2019, Introduction to the Capacity Auction [pdf]

IESO, Oct 2019, Market Manual 12: Capacity Auctions 7.0 [pdf]

IESO, Jul 2017, Submitting, Revising and Cancelling Energy Bids [pdf]

Day-Ahead Commitment Process

IESO, Mar 2020, Day-Ahead Commitment Process [website]

IESO, Jul 2017, Guide to the Day-Ahead Commitment Process (DACP) [pdf]

IESO, Oct 2019, Market Manual 4: Market Operations Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets (Issue 60.0) [pdf]

Non-Performance Charges and Baselining

IESO, Apr 2020, Charge Types and Equations (Issue 69.0) [pdf]

IESO, May 2020, Market Manual 5.5 Part 5.5: Physical Markets Settlement Statements (Issue 77.0) Section 1.6.26.3.1 [pdf]

Resources for further analysis

IESO, Mar 2020, Operability Assessment [website]

IESO, Jun 2019, Review of the IESO-Controlled Grid's Operability to 2025 [pdf]

IESO, Mar 2020, Reliability Outlook [website]

IESO, Dec 2018, Reliability Outlook - An adequacy assessment of Ontario's electricity system (Jan 2020 to Dec 2024) [pdf]

IESO, Mar 2020, Creating the Electricity Marketplace of tomorrow [website]

IESO, Oct 2011, Dispatchable Load Operating Guide [pdf]

Appendix F - Glossary

Acronyms used in this document:

Acronym	Expression
ADMS	Advanced Distribution Management System
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure
BCA	Benefit Cost Analysis
BM	Balancing Mechanism (UK)
BtM	Behind-the-Meter
C&I	Commercial and Industrial
CAOR	Control Action Operating Reserve
CAP	Capacity Auction Participant
CDM	Conservation and Demand Management
CIM	Common Information Model
CMP	Capacity Market Participant
DACE	Day-ahead Commitment Engine
DACP	Day-ahead Commitment Process
DER	Distributed Energy Resource
DL	Dispatchable Load
DLMP	Distribution Locational Marginal Prices
DR	Demand Response
DRA	Demand Response Auction (CA)
DRWG	Demand Response Working Group (CA)
DSR	Demand Side Response
DNO	Distribution Network Operator (UK)
DMS	Distribution Management System
DSO	Distribution System Operator (UK)
EOSCA	Emergency Operating State Control Action
ESAG	Energy Storage Advisory Group

FFR	Firm Frequency Response
FoM	Front-of-Meter
GA	Global Adjustment
HOEP	Hourly Ontario Electricity Price
ICA	Incremental Capacity Auction (CA)
ICI	Industrial Conservation Initiative (CA)
IESO	Independent Electricity System Operator
ISO-NE	ISO-New England
HDR	Hourly Demand Response
LDC	Local Distribution Company (CA)
MCP	Market Clearing Price
MDMR	Meter Data Management System
MFR	Mandatory Frequency Response (UK)
MMCP	Maximum Market Clearing Price
MOECC	Ministry of Environment and Climate Change
MRP	Market Renewal Program
MW	Megawatts
NDL	Non-dispatchable Load
NERC	North American Electric Reliability Corporation
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission
NGESO	National Grid Electricity System Operator
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO
OEB	Ontario Energy Board
OEFC	Ontario Financial Corporation
OR	Operating Reserve
OMS	Outage Management System
PJM	Pennsylvania-Jersey-Maryland
PV	Photovoltaic

RMR	Reliability must-run
SaaS	Software-as-a-Service
SAR	Shared Activation of Reserve
SCADA	Supervisory Control and Data Acquisition
SIA	System Impact Assessment
STOR	Short Term Operating Reserve (UK)
TERRE	Trans European Replacement Reserves Exchange
TRA	Transitional Capacity Auction (CA)

Energy legislation and regulation referenced in this document:

- Ontario Energy Board Act (OEBA) 1998
- Ontario Electricity Act (OEA) 1998
- Ontario Green Energy Act (GEA) 2009