

EVOLVING BUSINESS MODELS

For Renewable Energy Co-operatives

A photograph of a diverse group of eight people of various ages and ethnicities standing in a grassy field, smiling and looking towards each other. They are dressed in casual attire. A red banner is overlaid at the bottom of the image.

Spotlight on Solar and Storage

May 2019

About TREC

TREC Renewable Energy Co-operative is a non-profit organization that advocates for and supports the transition to 100% renewable energy. Founded in 1998, TREC built the first co-operatively owned wind turbine and founded one of the largest solar co-operatives in North America. TREC believes our energy future must involve Community Ownership by the local residents to build community resiliency and enable sustainable economic practices.

TREC works closely with others in the co-operative and environmental sectors as well as with Indigenous community groups to support their renewable energy projects. In partnership with our charitable sister organization Relay Education, we promote and support knowledge sharing, skills development and training for youth and leaders.

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Disclaimer

The information in this report is intended to help co-operatives and potential partners in the understanding of the potential benefits and challenges in renewable energy project development. It should only be used as a supplementary guide when considering whether to devote time and resources toward developing a project. It is not a legal interpretation of any policies, programs or regulations, nor does it intend to provide detailed program and eligibility criteria. Links to government legislation, policies and programs have been provided, however the authors are not responsible for outdated information or changes that have occurred since the writing of this report.

List of Acronyms

AC	Alternating Current
BES	Battery Energy Storage
BIA	Business Improvement Area
BOMA	Building Owners and Managers Association
BTM	Behind-the-meter
CDM	Conservation and Demand-Management
CMHC	Canada Mortgage and Housing Association
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
EDA	Electricity Distributors Association
EE	Energy Efficiency
ESI	Efficiency-related split incentives
ESPC	Energy Service Performance Contract
EV	Electric Vehicle
FIT	Feed-in Tariff
FTM	Front-of-the-meter
GA	Global Adjustment
GHG	Greenhouse Gas
HOEP	Hourly Ontario Electricity Price
HONI	Hydro One Network Inc
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
kVa	Apparent Power
kW	Kilowatt
kWh	kilowatt hour
LDC	Local distribution company
LSM	Local Service Manager
MSI	Multi-tenant, multi-owner split incentives
MURB	Multi-Unit Residential Buildings
MUSH	Municipalities Universities, Schools, and Hospitals
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability
NM	Net-Metering
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OREC	Ottawa Renewable Energy Co-operative
PM	Property Manager
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Co-operative
RFP	Requests for Proposals
RGI	Rent geared to Income

ROI	Return on Investment
RPP	Regulated Price Plan
SHP	Social Housing Provider
SNAP	Sustainable Neighbourhood Action Plan
TOU	Time-of-Use
TPO	Third Party Ownership
TRCA	Toronto Region Conservation Authority
TSI	Temporal Split Incentive
USI	Usage-related split incentives
VNM	Virtual Net-Metering
VPP	Virtual Power Plants

Executive Summary

As in many jurisdictions, the Energy Sector in Ontario is going through major upheavals which are likely to last through the next decade. The public utility model that has been the engine of growth for western economies for over a century is clearly in crisis. In almost every G20 nation, their local utilities, system operators, generators, regulators and government ministries are struggling to grapple with spiralling costs, uncertain demand, ratepayer anger and the fear of grid defection.

Ontarians have enjoyed the benefits of an electricity grid that is mostly clean, mostly reliable, widely accessible and relatively affordable. But the future energy consumption needs and ratepayer expectations are changing dramatically and at a frenetic pace. The clearest challenge to the current centralized-control model comes from the worldwide consumer adoption of the highly disruptive, fully-distributed ‘do it yourself’ electricity generation from solar panels. 80% cost reduction in 5 years gets people’s attention.

As with any large, complex system, there is an inherent inertia that does not adapt easily to change – especially disruptive change. The Ontario electricity system operator (IESO) along with the Ontario Ministry of Energy have engaged in years of consultations in public and private forums. The key policy options for the mid-term (5-7 years) are well documented but there is no clear roadmap nor timetable for introducing the required new policies and regulations. The inevitable changes will come; that much is certain.

Since 2009, Renewable Energy Co-operatives (RECs) in Ontario have demonstrated the ability to mobilize community support and to raise community capital to finance their community-scale projects. With the ending of the FIT program in December 2017, these volunteer-led organizations are pro-actively seeking new opportunities to advance the adoption of renewables into their communities. This report lays out a set of potential roadmaps for RECs to build out a vibrant, viable business model that can adapt as the policy landscape evolves – and can perhaps help to expedite that evolution.

The two drivers of the business models, as contemplated, are economics and regulatory environment. The public utility model divides the stakeholders at the meter, as defined by the regulator. All ratepayers operate behind the meter (BTM) in an unregulated environment; the IESO system operator, local utilities, bulk power suppliers and HONI transmitters operate in front of the meter under OEB regulatory oversight.

The FIT program specifically opened the door to empower community co-operatives to become suppliers to the IESO system. RECs learned, invested and developed projects

across the province and are now operating them under 20-year supply contracts. The favorable economics and stable long-term contracts built a thriving business model. This central procurement model for renewables is unlikely to be repeated in the future.

In 2019, the only opportunity for RECs is to be a supplier to the ratepayer, operating behind the meter. The rules that govern this situation fall under Net-metering (NM), discussed more fully in chapter 1. The current solar economics do make this model viable, for projects of a certain scale, if the ratepayer is a long-term stable entity. This represents an exciting opportunity for RECs, by working with local Municipalities and local LDC utilities, to build on their past successes to accelerate their community's adoption of solar. Local examples of success are contagious, when promoted properly.

The amended Net-metering rules introduced in 2018 permit the inclusion of energy storage in projects. However, at present there is no viable business case for storage under current Ontario rates, except for very large Class A customers. Rapidly dropping storage costs (76% since 2012¹) will eventually change that picture but likely outside of the 5-7 year window. We include several interesting storage examples from other jurisdictions which are examined in Chapter 3.

The REC community has long advocated for Ontario to adopt the Virtual Net-metering (VNM) rules that have created a tsunami of community-owned 'Solar Gardens' across 17 US states. The Ministry of Energy came close to introducing these rules in 2016 but then retracted them, citing further consultation needed. If re-introduced, VNM would create a ten-fold increase in distributed solar generation within years. Chapter 3 fills in some of the details of the new business models possible under such an open framework.

Over the longer term, the greatest positive impacts will come from operating under a new model of co-operating 'across the meter' - between the local LDC utility and the BTM ratepayers. Instead of 'us vs them' it holds the promise of delivering economic benefits to all stakeholders. The RECs can play an enabling facilitator role, building upon their community focus and capacity to mobilize community support. As the IESO evolves the market for ancillary services, and as the LDCs themselves evolve, this could be the ultimate business model for the sector.

These models are presented using a Business Model canvas.

¹ Utility Dive. (March, 2019). Electricity costs from battery storage down 76% since 2012.

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1. Overview of the Ontario Electricity Sector

Ontario's electricity sector is made up of a number of independent entities, operating as a competitive monopoly. In Ontario, only the grid operator may buy and/or sell electricity. The major entities are:

Independent Electricity System Operator

The IESO oversees the planning, operations, reliability and evolution of Ontario's electricity system. They administer the competitive wholesale markets, procure supply contracts, dispatch generators, monitor real-time performance, and manage power flows with neighbouring grid operators. The IESO works with the Ministry of Energy to develop long range plans, financial models, design requirements and investment recommendations.

Transmission System Operator

The high voltage Province-wide transmission grid is owned and operated by Hydro One (HONI). This transmission grid interconnects large generators to the local distribution companies, who deliver the power to customers connected to their distribution grid. Customers with much higher demands are connected directly to the transmission grid. This HONI grid interconnects to neighbouring grids in Quebec, Manitoba, New York, Michigan and Minnesota.

Local Distribution Companies

The LDCs were conceived as a 'poles & wires' company, responsible for delivery of electricity purchased from the IESO markets to ratepayer customers connected to their local distribution grid. They are also the system's face to the customer, providing customer communications, client billing and setting local standards of service. There are around 70 LDCs in Ontario, most of which are municipally-owned.

Market Participants

The IESO markets are restricted to registered market participants. This includes generators, transmitters, distributors, wholesalers, retailers and load customers.

Ontario Energy Board - Regulator

The OEB is responsible for licensing, regulations, standards compliance and safeguarding the public interest. They approve all pricing and rate structures.

Minister of Energy

The Minister provides direction and oversight by Ministerial Directive to IESO, OEB.

Competitive Market Design

In Ontario, the electricity market is a hybrid design between a competitive spot market and long-term bilateral fixed-price contracts for supply. The wholesale markets for the delivery of electricity are made up of the real-time energy market and the ancillary markets. The wholesale energy market price consists of the Hourly Ontario Electricity Price (HOEP) and the global adjustment (GA) charge. The HOEP is based on the bids submitted by Market Participants.

The GA is the difference between the wholesale market price of electricity and the actual cost which is comprised of regulated rates for generators, plus the price guaranteed to generators in fixed-price contracts, plus the cost of IESO-financed programs such as energy conservation programs. Since its inception, GA has grown dramatically from 4-6% of a typical bill to 80-85% of the same bill.

Ancillary Markets

The ancillary markets ensure the reliability of the grid. The services are procured by the IESO including black start, regulation and voltage control, and reliability must-run. The IESO periodically holds auctions to procure assets to deliver these services.

Market Renewal Program

The IESO is currently restructuring the competitive market to modernize, optimize and improve efficiencies in the current system. The Market Renewal program intends to introduce a Day-Ahead market for the competitive procurement of electricity supply. An incremental capacity auction will be introduced to secure reliable supply of capacity in the long-term by providing guaranteed revenues for having capacity available when it is needed.

1.2. Rate Classes

The LDC's customers are primarily grouped into four classes depending on the demand they put on the grid:

- Residential customers,
- General Service customers with less than 50 kW of demand,
- General Service customers with greater than 50 kW of demand, and
- Intermediate to Large customers.

The first two groups are generally billed on a time-of-use basis, while customers above this threshold are considered demand customers and are billed according to peak power consumption in addition to their per kWh consumption.

1.2.1. Time-of-Use Customers

Residential and small commercial customers use the grid in similar ways and therefore most LDCs charge time of use (TOU) rates for these customers. TOU charges customers per kWh of consumption at different rates throughout the day, that correspond to when electricity demand is off-peak, mid-peak and on-peak.

By charging higher rates during mid- and on-peak times, customers are incentivized to shift consumption to off-peak hours. The GA is incorporated into TOU customers bills as part of their regular billing cycle.

These customers include residential, small commercial buildings, bulk metered multi-unit residential units of up to 6 apartments or units, as well as farms and small retail.

1.2.2. Demand Customers

General Service customers with >50 kW peak demand are the most diverse of any class. They consist of larger bulk metered multi-residential buildings, livestock intensive or greenhouse farming, larger retail and big box stores, as well as smaller industry such as print shops or metal forming. These customers are billed a fixed monthly service charge plus a variable demand charge based on their maximum monthly demand in kW, and a per kWh charge for their consumption. The consumption charge can be the wholesale electricity market price plus GA or it could be a fixed rate.

All LDCs have an upper limit to this class even if they do not currently have intermediate or large customers.

Some LDCs have intermediate rate classes (Class B) which range from 1,500 kW or 3,000 kW up to 5,000 kW.

Large customers (Class A) are defined as greater than 5,000 kW. Typical kinds of buildings in this rate class are office/retail complexes, hospital complex, university campus and large industrial customers such as an automotive plant.

Both Intermediate and large customers are billed a monthly fixed service charge plus a variable demand charge based on apparent power (kVa) and a per kWh charge for their consumption. kVa is used to take into account whether or not the LDC has to install special equipment to manage power quality in order to serve the customer.

1.2.3. Industrial Conservation Initiative

The IESO introduced the ICI to incentivize large Class A customers to shift their demand away from the Ontario-wide peaks. They pay GA based on their percentage contribution to the top five peak Ontario demand hours each year. By shifting their peak, they reduce GA for the whole year.

Intermediate Class B customers with peak demand >500kW can now opt-in to the ICI program. (Figure 1).

Class B customers under 500 kW of peak demand or those who decide not to opt-in are charged based on the HOEP plus the GA charge determined by the IESO. The IESO offers LDCs three choices of how the GA is calculated for these customers².

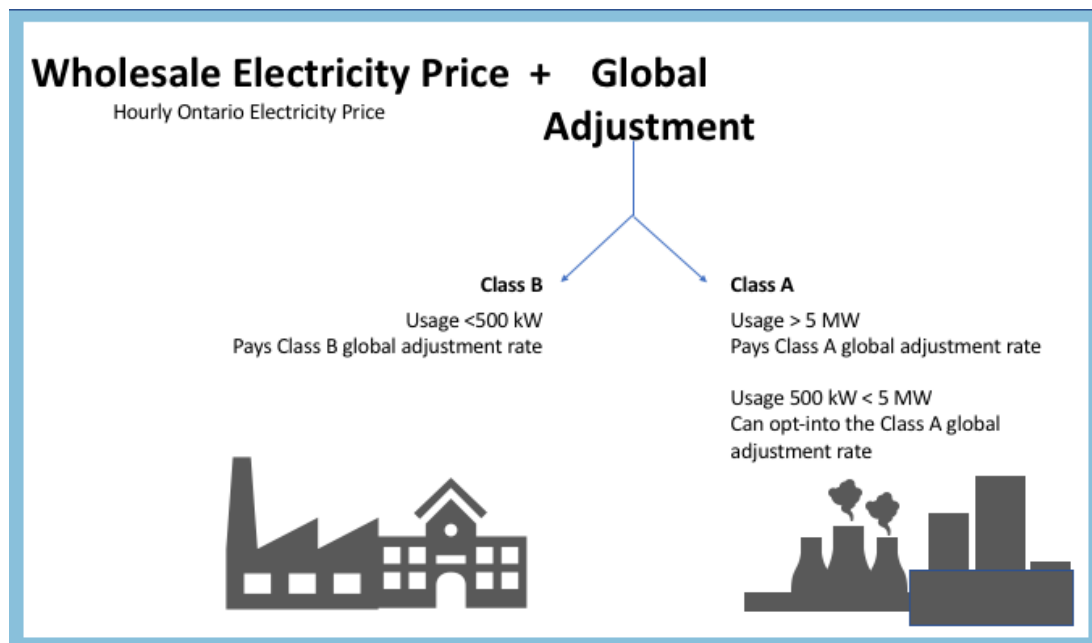


Figure 1. Class A & Class B Rates

² <http://www.ieso.ca/en/Learn/Electricity-Pricing/Global-Adjustment-for-Mid-sized-and-Large-Businesses>

1.3 Net-metering Policy

Residents and businesses in Ontario have the right to generate electricity from renewable sources, primarily for their own consumption. Net-metering rules allow customers with BTM generation on their property to enter into a net-metering contract with their local LDC. This allows them to reduce the electricity supplied from the grid – they pay the ‘net’ usage only. Furthermore, if they generate more than they use, they may convey any excess electricity into the grid in return for credits on their future bills. Credits are valued at the retail rate the customer pays according to their rate class, and unused credits can be carried forward over a 12-month period.

The former limit on the size of a Net-metered system has been removed, allowing any size system to be installed on a property. Current net-metering policy allows the use of energy storage in conjunction with BTM generation and allows the storage device to charge and discharge from the grid.

The expectation of most property owners was that they would be earning credits based on TOU, since that was how they pay for electricity. However, once contacted to enroll in a net-metering program, many LDCs will switch the customer from TOU to tiered RPP pricing. Some LDCs have been issuing TOU-based credits; the treatment is not standard. The government is reviewing the rules and is expected to provide a resolution in 2020.

To enable an Ontario-wide approach for TOU net-metering, updates will be needed to the Smart Meter Data Management System.

The RECs in Ontario want to see the Net-metering rules extended and enhanced. Two specific additions are needed:

1. Third Party Ownership (TPO). Currently, the solar generation capability must be owned by the Load Customer, i.e. the property owner. By permitting TPO, the REC could own and operate the generation and sell the power to the Load customer under a Power Purchase Agreement. This is allowed in 17 US states.
2. Virtual Net Metering (VNM). Currently, the solar generation capability must be located on the Load site where the power is consumed. By permitting VNM, the solar may be located on the most optimum site, it can be scaled to the optimum size and the credits ‘sold’ to a group of customers to lower their individual bills.

2. Energy Storage

Recent studies in the US of battery energy storage (BES) have demonstrated that at scale, battery technologies can provide a range of values to different stakeholders. The optimum value is therefore achieved by providing multiple value streams from a single energy storage unit. This is called value stacking (**Figure 2**). Value stacking is essential to the business model for energy storage as a single revenue stream usually does not provide an adequate payback and ROI. When a battery is deployed for a single application it often sits unused for over half of its useful lifetime³.

However, value stacking can be constrained by technical or regulatory limits. Batteries designed for one application may not be suitable for another. Two factors determine which application a battery is best suited for: power capability (MW) and energy capability (MWh). For example, in a BTM application where the battery is being used to reduce peak demand from the grid, a customer with high peaks of short duration would need a battery with high power capability, whereas a customer with flatter loads with peaks of longer duration would need higher energy capability.

Procurers of battery energy storage (BES) services require assurance that enough charge is available when it is needed and is not being used to provide a different service, limiting other services they can participate in. The development of proper control algorithms, meters that can measure production and consumption at smaller intervals, and communication between facilities and grid operators and end-users becomes essential.

Energy storage will also be able to participate in the upcoming demand response (DR) auction as a trial for the IESO's proposed capacity market design. A number of other energy storage pilot projects in Ontario have also been implemented by LDCs or consortiums of stakeholders including project developers, LDCs and academia.

At present, the sole viable business case for BTM BES in Ontario lies in reducing Demand charges for large Class A load customers. Until recently, the GA charges imposed were a major barrier to energy storage. While charging from the grid the full GA was charged based on consumption, plus any additional demand charges. However, when injecting back into the grid the facility could only recover wholesale HOEP costs.

Regulatory amendments to the Electricity Act on July 1, 2018 have provided some clarity as to the use of energy storage and removed some of the cost barriers. As per the amended regulation, energy storage is now defined as a Class B market participant or a

³ Rocky Mountain Institute. (2015). The economics of battery energy storage.

Class B consumer. In addition, the GA for Class B storage facilities (those with a peak demand under 1 MW) are reimbursed for the amount of energy consumption that is re-injected into the grid, therefore removing some of the demand charge barriers faced by energy storage.

Despite these amendments, current energy storage prices prevent energy storage from being economically viable in most cases. However, industry stakeholders have indicated that as electricity prices in Ontario escalate and energy storage prices continue to fall, BES business cases are expected to become more viable in the next 5 to 10 years.

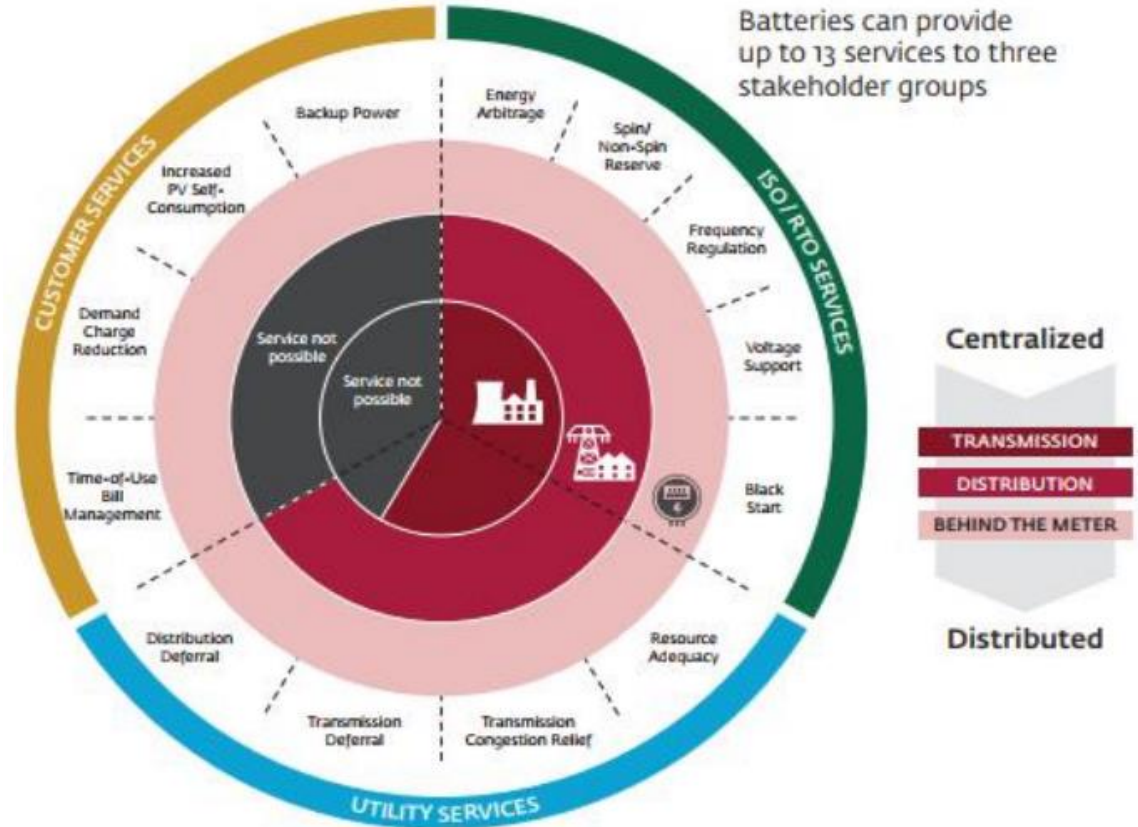


Figure 2. Value stacking opportunities of battery energy storage

The value that can be delivered is also determined by where in the grid the battery is located. Batteries can be located BTM on an end-user’s property, front-of-the-meter (FTM) in the distribution grid or in the transmission grid. **Table 1** provides estimates of the value of services provided by BES in Ontario and **Table 2** shows where in the distribution system a BES system needs to be located to best provide those services.

If these assets can be aggregated by a REC into a single portfolio that the LDC sees as one resource then, this creates even more value by allowing for greater and more coordinated reductions in peak demand. It may also open up opportunities for REC participation in wholesale markets, which have minimum 1 MW thresholds which are out of reach by any Ontario REC today.

Table 1. Estimated range of monetary value provided by a 1 MW, 4 MWh battery in Ontario⁴

Benefit	Monetary Range (\$ per MWh Delivered)	Assumed Number of MWh per year	Total \$ Per Year
Market Arbitrage	\$13.90 - \$23.50	1460	\$20,294 - \$34,310
Distribution System Upgrade Avoidance	\$12.87-\$133.56	1460	\$ 18, 790 - \$194,998
New Generation Capacity Avoidance	\$12.15 - \$25.23	1460	\$17,739 - \$36,836
Redundant Power Supply (Reliability)	\$3,900 - \$26,000	10	\$39,000 - \$260,000
Non-Spinning Reserve Availability	\$0.20 - \$30	1460	\$292 - \$43,800
Spinning Reserve Availability	\$0.20 - \$54	1460	\$292 - \$78,840
Reserve Activation	\$0.40 - \$135	730	\$292 - \$98,550
Power Quality Improvement	\$6.06 - \$11.35	3025	\$18,332 – \$34,334
Frequency Regulation	\$45 - \$65	3025	\$136,125 - \$196,625
Voltage Control	\$8.30 - \$58.50	3025	\$20,294 - \$34,310
Black Start	\$5.85 -\$36	10	\$58.50 - \$360
Reduced Dispatching of Peaker Facilities	\$110 - \$170	1460	\$160,000 - \$248,200
Global Adjustment Charge Reduction (Class A)	\$80,000 - \$150,000	5	\$400,000 - \$559,310

⁴ Essex Energy Corporation. (2017). The Study of Energy Storage in Ontario's Distribution System.

Table 2. Benefits of energy storage according to location in the distribution grid⁵

Currently Monetizable Benefits	Distribution Connected Energy Storage Location			
	At TS	Middle of Feeder	End of Feeder	Behind Meter
Market Arbitrage	✓	✓	✓	✓
Distribution System Upgrade Avoidance	✓	✓	✓	✗
New Generation Capacity Avoidance	✓	✓	✓	✗
Redundant Power Supply (reliability)	✓	✓	✓	✓
Non-Spinning Reserve Availability	✓	✗	✗	✗
Spinning Reserve Availability	✓	✗	✗	✗
Reserve Activation	✓	✗	✗	✗
Power Quality Improvement	✓	✓	✓	✓
Frequency Regulation	✓	✓	✓	✗
Voltage Control	✗	✓	✓	✗
Black Start	✓	✓	✗	✗
Reduced Dispatching of Peaker Facilities	✓	✓	✓	✓
Global Adjustment Charge Reduction (Class A)	✗	✗	✗	✓

Backup power for government, commercial or multi-tenant buildings is of growing value as the impact of severe weather events has documented in the last few years. Therefore, there is growing role for energy storage to provide backup power instead of meeting minimum emergency power requirements with diesel generators. For grocery stores or restaurants backup power can be very important to prevent any food spoilage that may occur during an outage.

The value of the resiliency provided by backup power during outages is however difficult to quantify. For the commercial or institutional sector, resiliency can be quantified by estimating lost money during an outage. The National Renewable Energy Laboratory (NREL) has quantified the value of resiliency by incorporating the avoided cost of outages

⁵ Essex Energy Corporation. (2017). The Study of Energy Storage in Ontario's Distribution System.

into optimal sizing considerations for solar plus storage systems for different building types (**Table 3**). Resilience here is defined as being able to meet critical loads for 2 hours.

Table 3. Value of resiliency for the commercial and institutional sector

Building Type	Value of Resiliency (\$/hour)
Primary School	\$2,368
Office Building	\$14,365
Large Hotel	\$5,317

The regulation and voltage control markets are currently the most common application of energy storage in Ontario as well as in US markets. The most recent numbers published by the IESO put the total amount paid for ancillary services in 2017 at \$73,846,757. The most recent RFP for regulation service was valued at an average price of \$200,000 per MW-year. This represents important revenue streams for fast responding energy storage devices such as batteries.

Aggregation of individual BTM storage and solar assets into virtual power plants (VPP) has high potential to deliver value to all stakeholders involved. While there is much discussion on the potential of VPP's there are only two pilot projects in Ontario that have tested this model: Alectra's PowerHouse, and Ottawa Hydro's GREAT DR Protocol. Alectra was the first to pilot this model and is therefore the only one that has produced publicly available results so far. The GREAT DR protocol is still in the development stages but looks to develop a platform to allow decentralized energy transactions between individual households, the LDC and wholesale markets.

3. REC Value Proposition

Each of the successful RECs across Ontario has learned how to tap into the expertise and skills of their membership. They draw upon willing and capable volunteers to identify promising projects, to mobilize community capital and to marshal relevant technical resources. They have proven their capabilities to develop, construct and operate successful solar projects. They know how to work cooperatively and collaboratively.

In a survey of Ontario Municipalities conducted in Fall 2018, the 2 primary barriers to implementing community energy plans were a lack of effective stakeholder engagement and access to community energy project financing. RECs and Municipalities should make ideal partners, forging new and innovative models of collaboration.

The value and capacity that RECs bring to the table must evolve in lock-step with the changing regulatory environment. One of the main drivers of regulatory change will be the LDCs themselves, who are advocating a new business model that goes well beyond the 'pole & wires' model. They propose to devolve the role of 'system operator' from the province-wide level of the IESO mandate to a more local role within their footprint. They are seeing the need to balance supply, demand and storage on a municipal scale. And they are convinced that co-operation and collaboration is key to their success.

3.1. Short-term value

The skills, expertise and reputation that the RECs have built within their communities during the FIT program provides a solid foundation for future growth. The most immediate opportunities are obvious- promoting and developing solar net-metering projects in the commercial and institutional sectors.

Solar developers in eastern Ontario are actively winning clients for net-metering projects, primarily in the farming community. These farmers are running long-term stable businesses which use significant amounts of electricity. The focus has been on projects in the 100kW to 350 kW range, which are at a scale that is financially viable. Even so, payback timeframes are in the 12-14 year range under current Ontario rates. Most farmers are able to own, operate and finance their projects.

By tapping into their member networks, RECs are well positioned to identify and engage with commercial building owners that mirror the attributes of the farmer. They will need to develop long-term relationships that are flexible and sustainable. The primary benefits are energy savings and cost certainty over the length of the contract, in addition to the

environmental benefits. The reputation and stability of the REC is a decisive factor for any potential partner, as these contracts can last 20 to 30 years.

As an example, ORECs analysis of a Class B commercial customer gives attractive results for a 600kW system yielding a payback of 10 years and an IRR of 10.76%.

The RECs have demonstrated their competence in solar in a variety of business models— they own 100% of some projects, co-own projects held in Joint Ventures or Limited partnerships, or operate projects under an equipment lease. This flexibility is essential in the commercial sector – few of the business owners have expertise and/or capacity to operate the project; some will have access to capital financing but some may not. The capacity to operate, administer and maintain a solar project is a key REC strength.

In California in 2010, it was documented that adoption rate of solar by homeowners more than doubled when residents could actually see 4 projects in their neighborhood or on their commute. The RECs in Ontario found a similar behaviour by investors – interest in investing in community solar multiplied once they could visit solar projects on local schools, community centres, community housing or municipal buildings.

The community focus for RECs is ideal to spur commercial and institutional entities to consider net-metering and to take effective action. RECs can convene all the property owners in a neighbourhood to invest together, rather than approaching business cases individually, which is the solar developer model. A collective business case can be a beneficial tool – each building owner has their own financials and ownership but the installation costs, equipment costs, maintenance costs and financing costs can be shared or purchased under a group discount.

Third-party ownership models are attractive to many businesses as they require no or low capital outlays on the part of the building owner. The REC handles the procurement and supplies the capital needed to install solar on the property. The contract terms can be tailored to the needs of the partners- fixed price, escalating price, tiered price. The ownership of the actual equipment can be transferred over time, or at a certain date.

Solar Leasing and Power Purchase Agreements (PPA) are the two third-party ownership mechanisms that have been commonly used to finance solar projects throughout the US and to some extent in Canada. In Ontario, third-party ownership is not allowed for net-metering, so solar leasing is currently the only mechanism that can be used. Advocacy for new net-metering regulations is continuing with some expecting PPAs to become admissible within the next 2 years.

The primary value of net-metering for commercial clients is to dramatically reduce their electricity bill, protect them from rising electricity prices, and in some cases to provide back-up power as long as the panels are producing. Adding storage to their project at current market rates does not provide an attractive return for projects of this scale.

The value provided will also depend on the billing methods that LDCs use for net-metering credits going forward. Once the government decides to permit (or require) TOU pricing, then the business case for net-metering will improve substantially. Today, many LDCs switch customers to a tiered rate plan for net-metering. This diminishes the value of solar as the business owner is not able to take advantage of higher rates when solar generation aligns with peak demand. However, depending on the customer's load profile switching to tiered rates could be beneficial if for example they tend to consume lots of electricity during peak demand.

As an example, OREC's analysis of net-metering in small commercial buildings uses the example of a community centre with a 47kW system. Under TOU the project yielded favourable results with a payback of 9 years and IRR of 12.4%. However, under tiered rates the business case became more difficult and the payback would jump up to 18 years.

Solar Leases

Under a solar lease, the building owner is "the generator" to qualify for net-metering. The REC is not selling power to the building owner but simply leasing the solar equipment to him/her. The REC operates and maintains the equipment under separate contract.

Solar leases are similar to other types of equipment leases in that the building owner pays monthly installments over the term of the lease. The payments may be fixed over the term, or often with an annual rate increase, or escalator of 2% to 4% included in the terms. At the end of the term which is typically 20-30 years, the owner has the option to own the equipment or the equipment is removed from the site and returned to the provider.

The savings earned by building owner are directly linked to the solar production, which varies according to the sunshine available. Production is also tied to the capacity and output of the solar array which will degrade slowly over time. The Lease must be designed so that the risk is shared by both parties. This can be mitigated through the inclusion of a performance guarantee.

In addition to the monthly lease model, there are also pre-paid lease options. Pre-paid leases allow the building owner to make an initial upfront payment to decrease the monthly amount, and the REC usually foregoes annual escalator. Most leases include

provisions to incur other financial penalties for terminating the lease too early. More information on key lease terms can be found in Appendix E.

Solar PPAs

Under a Power Purchase Agreement, the REC will be “the generator” and sells the power generated by the project to the building owner, to be applied against their consumption under a net-metering contract with the LDC. The PPA is a supply contract which can be tailored to the current rate structure but adjusted as future rate changes are introduced by the OEB. The REC gets paid for the actual energy delivered, which changes the risk profile compared to the solar lease.

Generally, PPA prices are tied to present and future electricity prices. The price is often a premium during early years and transitions to a discount in later years. To avoid rate increases that exceed the actual utility rate, PPAs often contain provisions that limit increases in the electricity rate paid.



Figure 3. Third Party Ownership models, Solar Lease vs. Solar PPA

3.2. Medium-term value

The value that RECs can bring to the local economies is expected to jump by an order of magnitude in the medium-term, powered by two regulatory changes and the continuing plunge in the costs of solar and storage technologies.

Virtual Net Metering

The current rules for net-metering restrict the location of the solar panel arrays to be co-located on the same site as the load customer. The business case for net-metering is only viable for single sites over a threshold scale of consumption, currently over 100kW size.

Virtual net-metering removes the location restriction. As presented by the Ministry of Energy during public consultations, there are two different models under consideration –

1. Multi-site net-metering would allow a corporation owning more than one building to generate on their largest site but apply net-metering credits to any of their bills. This is particularly attractive to Municipalities - they could put a large solar array on their arena roof but use excess generation to offset bills for streetlighting or the water treatment plant. There would be distance restrictions (or not) on how far away the generation site is located from the others.
2. Multi-party net-metering would allow a ‘generator’ to locate a solar array of any size on any property which is optimal, with or without a local load. The generated power is fed into the local LDC grid, generating net-metering credits. Those credits may be sold or transferred to one entity or to many. This model is highly successful in creating ‘Solar Gardens’ in a dozen jurisdictions in the US.

The multi-party net-metering model is ideal for RECs and ideal for neighbourhood action. This will allow the REC to be the generator and sell credits to its members in addition to larger ‘anchor tenants’. Solar arrays could be maximized on commercial buildings and municipal buildings and brownfield locations. The core business case could be de-risked by long-term contracts with mid-to-large companies or the Municipality. Remaining credits could be sold or transferred to homeowners, to renters, to low-income tenants or to condos. This model is truly inclusive as entire neighbourhoods can participate.

This model will allow the REC to construct the solar array at maximum scale and in an optimum configuration, rather than constraining the size to match the load customer’s annual consumption patterns. This optimization has immediate benefit as it drives down the capital cost and the ongoing benefit of shared maintenance costs. The REC could build and operate a ‘portfolio’ of neighbourhood solar arrays, to the benefit of the community.

Behind the Meter Aggregation

The IESO currently operates a successful Demand Response program, on a province-wide basis. Large load customers who can reduce their consumption ‘on request’ are contracted through an auction process. Then as needed, they ‘dial down’ their consumption by a set amount for a set period of time. This action helps the IESO meet anticipated short spikes in demand rather than dispatching additional generation.

In the most recent auction, the IESO awarded a contract to an ‘Aggregator’ in addition to the traditional large load customers such as huge steel plants or cement production facilities. The aggregator is being monitored to prove the technical ability to ‘dial down’ the consumption of its client’s multiple buildings across the province— so that in aggregate they could meet the minimum threshold to participate in the DR auction.

The LDCs through their association are advocates for operating this Demand Response at a local grid level, rather than just province-wide. They assert that this is an essential capability to assist in balancing the local grid. Local storage holds another key, as was demonstrated in the Alectra PowerHouse pilot. The LDC showed that it could benefit their local grid if they could ‘tap’ into BTM storage, requested that a portion of the local stored energy be fed into the grid when they encountered a local demand spike.

At the scale of a single home or a single business, the reduction in local consumption and/or the amount of energy storage that could be made available is not significant enough to the grid operator to warrant any investment. But with the local REC acting as a neighbourhood aggregator, the economics and the impact level is transformed. In essence, the REC is able to contract with the LDC and guarantee a minimum threshold of aggregate DR and/or aggregate delivery of stored energy. They can only do so if they already have in place energy contracts with those building owners and home owners.

BTM Aggregation at the neighbourhood level turns that neighbourhood into a neighbourhood ‘campus’. RECs can enable all property owners to cooperate to lower everyone’s costs and to benefit the local grid as well. Over the next decade, the local grid will face increased and likely different demand patterns as electric vehicles and fuel switching come into vogue- and this collaborative approach holds promise to solve that.

Ancillary Service Markets

The IESO also procures for ancillary service markets, buying specialized equipment to help maintain the reliability of the system. Storage systems are expected to play an increasing role as costs drop. However even with aggregation this is not likely a viable candidate business for RECs, even in the medium term. Additional information on IESO ancillary markets can be found in Appendix B.

4. Roles and Primary Activities

Every solar project progresses through three phases, displayed below (Figure 4). Each phase has a well-documented set of activities, milestones and deliverables. RECs can play any number of different value-adding roles in the different phases of the process as described below. In building their FIT projects, RECs always contracted the engineering, procurement and construction to a certified installation company. Some RECs took ownership after the projects were commercially operational; some owned the project from the initial design and were actively involved during development.

Project Development	Construction	Operation
<ul style="list-style-type: none">• Origination & Aggregation• Community engagement• Feasibility study• Contract development• Procurement• Control software development• Financing• Grid interconnection and permitting• Registration in wholesale and ancillary markets	<ul style="list-style-type: none">• Installation of equipment• Construction management• Commissioning	<ul style="list-style-type: none">• O&M• Oversee operation strategy• Participate in energy markets• Customer relationships• Performance reporting

Figure 4. Primary roles and activities in the solar and storage development process

4.1. Project Development Phase

Outreach: There are two outreach activities where RECs can add value –

Project origination and aggregation - REC identifies potential candidates for equipment leasing within its own member-base, through expanding the member-base or finding customers in the non-profit/co-operative housing sector, commercial sector or institutional sector. Aggregates solar (and storage units) for delivery of services to the LDC. Identifies opportunities for bulk purchasing. Provides initial conversations and proposals to building owners.

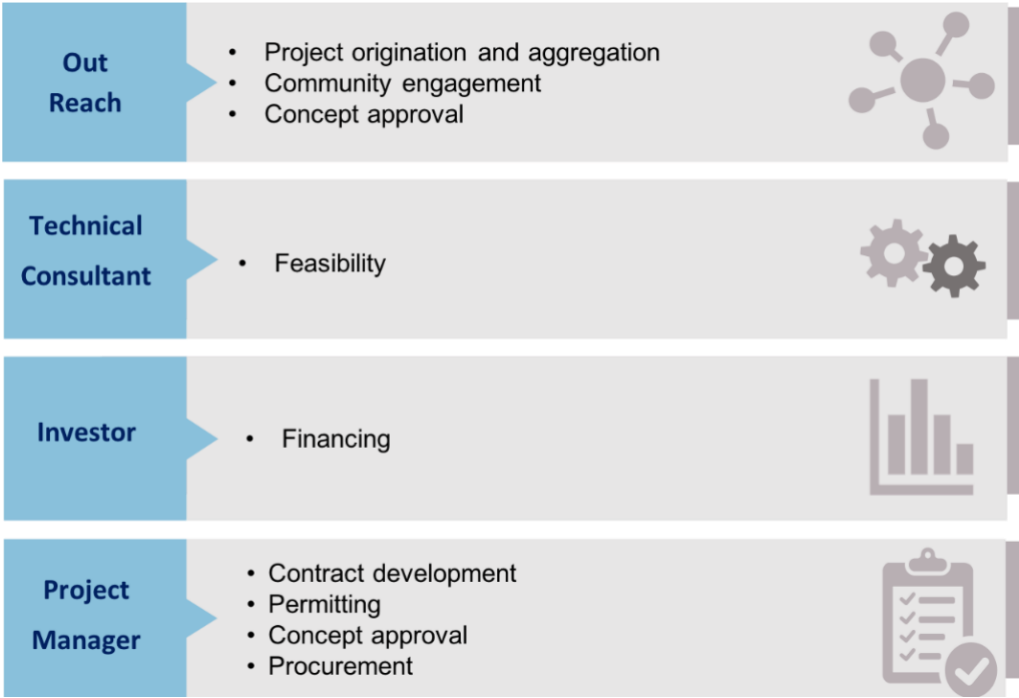
Community Engagement - Performs community engagement to determine level of support for work and educates community on project. Ensures that the concept is understood by all stakeholders (i.e. occupants, operations and maintenance staff,

building managers). Facilitates communication between stakeholders (equipment installers, LDC, home and, building owners).

Technical Consultant: Feasibility- Performs initial feasibility study for solar potential. Determines payback time and if level of investment is worth the projected savings.

Investor: Arranges community or third-party financing.

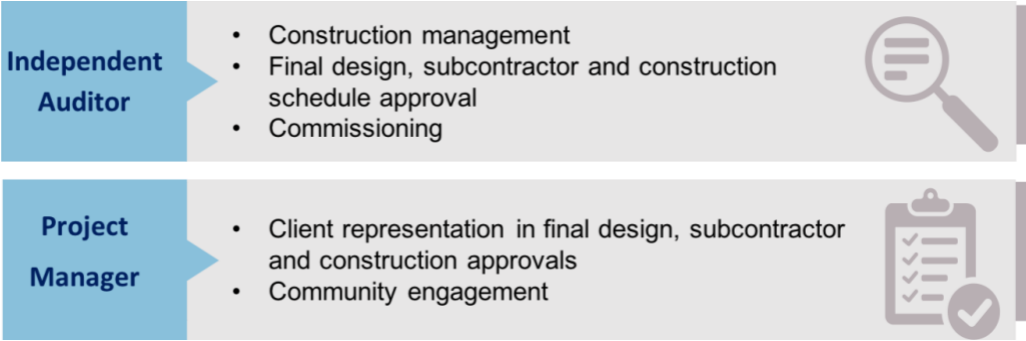
Project Manager: Develops leasing contracts with owners. Oversees necessary permitting applications. Finds and procures equipment suppliers, installers and necessary engineering services.



4.2. Construction Phase

Independent Auditor: Provides independent 3rd party oversight of the construction process. Produces commissioning/acceptance report that verifies the installer has met the approved final design and ensures that all required materials have been delivered. An independent auditor also produces commissioning report that verifies the installer has met the approved final design and ensures that all required materials have been delivered.

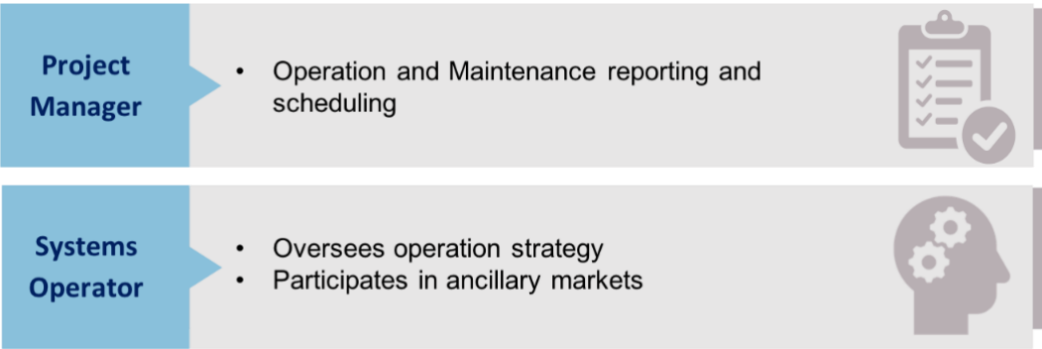
Project Manager: Represents interests of the building owner throughout the construction process. Signs off on bi-weekly detailed construction schedule and milestone payments. Communicates with community stakeholders: Ensures occupants and building owners are informed of the construction schedule and expected disruptions and receive adequate notice.



4.3. Operations Phase

Project Manager: Produces periodic reports on the financial performance of the system. Schedules and coordinates equipment maintenance, trouble-shooting and repairs.

System Operator: Oversees operation of the solar generation facility to optimize system benefits and maximize revenue to stakeholders. This becomes a much deeper role when BTM aggregation is implemented.



5. Market Segments

This section provides a profile of each of the Commercial, Institutional and Residential market sectors. If a neighbourhood approach is used, then all three sectors may be found in the same business model. Maps of the market segments can be found in **Appendix C**.



Figure 5. Three market segments for solar storage

5.1. Commercial Sector

The commercial sector provides the best scale for solar projects in terms of the amount of electricity consumption that can be offset and the rooftop space available for the solar arrays. Each project may be customized but a standardized set of contracts, leases and financial models can be used. With mid-sized companies it usually takes longer to develop contracts that are specific to their business needs. Roofs need to be structurally sound and in good repair to avoid having to remove the panels during a lease term to conduct repairs. Alternatively, roof repair could be conducted at the same time as installation.

In general, buildings that will be most suited for solar net-metering will have the following characteristics⁶:

- Located where the grid has capacity to take power
- South exposure with few obstacles that create shading. Development plans should be reviewed to ensure new construction does not block sunlight to the panels
- Building use and design is not expected to significantly change total energy consumption for the next 25 years.

⁶ OREC. (2017). Technical Report for the City of Ottawa: Review of Net Metering Opportunities, Barriers, and Implications for Solar Projects in Ottawa.

There are two very different types of companies in the commercial sector: large, sophisticated companies that have access to capital and expertise, and small to mid-sized companies that do not. Large companies may look to implement energy projects on their own using their in-house expertise and capital. These types of companies are generally driven by the following attributes:

- CEO values
- Internal skills
- Shareholders
- Competition
- ROI/profitability
- Consumer preference

In general market characteristics of the commercial sector include:

- Good potential for cost-effective emissions reductions
- Fewer end-use decision makers than residential
- Existing technologies can be deployed over wide areas using existing distribution channels
- Commercial building retrofits occur every 20 years on average to maintain asset value and attract tenants. Capital renewal periods are opportunities to increase energy efficiency
- Split-incentives under commercial leases
- 3-5-year payback periods for investments
- Large commercial has strong relationships with financial institutions and portfolios of properties
- Small and medium enterprises can have difficulty accessing financing

A real risk for the co-operative with the commercial sector whether using a solar lease or PPA model is the chance that the building owner may sell the business, go out of business or move before the contract term is up. If the building is leased, it is also important to consider the length of the tenant-landlord contract. In multi-tenant buildings this risk may be mitigated as the owner of the building could find other tenants to take their place.

Solar net-metering projects may not seem initially attractive to the commercial sector as many business owners want shorter paybacks, in the order of 3 years. However, Third-party ownership models that offer a no money down option and guaranteed stable energy costs over a long period can help overcome this barrier. RECs that can co-ordinate neighbourhood portfolios combining multiple projects can improve payback periods by group purchasing economies of scale.

Split-incentives in the Commercial Sector

The split-incentive problem is prevalent in the commercial leasing sector. A voluntary approach that is gaining increasing popularity in the US and Australia is green leases. This primarily occurs in individually metered buildings where the unit holder pays their own utility bill based on the metered consumption in their unit. The split-incentive occurs when the benefit of the energy investments made by the building owner accrues to the tenant. In a bulk metered building where one meter is used for the entire property and the utility costs are recovered through the monthly rent fees this problem is mitigated as the building owner can reduce their operating cost and improve their return on investment. A green lease creates a clause or a separate agreement that allows the building owner to raise the rent to finance EE improvements. The National Resource Defense Council has developed guidelines for how standard leases can be revised to include terms that address the responsibilities of landlords and tenants in terms of EE and how costs and benefits are to be shared. For more discussion on split-incentives see **Appendix D**.

Market Organization

The commercial sector can be separated into the retail, office, and industrial uses. It is typically categorized by whether a building is owned by the company or if the business is leasing the space from a property owner. Mixed-use facilities are another category that is characterized by office or apartment rentals above ground stores. The tables below provide a breakdown of the main categories of buildings in the commercial sector.

The appropriate market scale for co-operatives to aggregate in would be smaller sized community shopping centres, retail stores and Class B or Class C office buildings.

Retail

The retail sector is the most varied in terms of the different types of buildings and leasing arrangements. They can be single-tenanted, which are typically free-standing buildings, ranging from large box stores to small businesses on an urban street, such as mom and pop variety stores. The multi-tenanted segment includes non-freestanding buildings such as malls and shopping centres, that usually have larger anchor tenants located with smaller retailers. The segment could also include power centres which are multiple large free-standing box stores on a single lot with common parking and loading areas. Retail can also include special purpose buildings like stadiums, theatres, self-storage, etc.

Table 4. Non- free standing retail building types

Type	Description
Super-Regional Shopping Malls	Enclosed space, 800,000 sqft+, 5+ anchor stores with large variety of other tenants
Regional Shopping Malls	Enclosed space, 400,000-800,000 sqft, 1-5 anchor stores with other tenants
Community Shopping Centre	Open space, 125,000-400,000 sqft, general merchandise and commodities (supermarkets, department stores)
Neighbourhood Shopping Centre	Open space, 3,000-125,000 sqft, commodities for nearby neighbourhoods (e.g. drug stores)
Strip or Convenience Shopping Centre	Open space, less than 30,000 sqft, located along suburban transportation arteries
Lifestyle Centre	Main Street Concept with pedestrian circulation at core, and vehicle circulation around perimeter

Table 5. Free- standing retail building types

Type	Description
Bix Box Stores	50,000+ sqft
Power Centre	3+ big box anchor stores, multiple large buildings with parking in front, and smaller retailers clustered in a community shopping centre configuration
Retail Outlet	Manufacturers' outlet store, 50,000 to 400,000 sqft

Office:

Offices are categorized into Class A, Class B, and Class type buildings depending on their quality as defined by BOMA:

Table 6. Classification of Office buildings as defined by BOMA

Type	Description
<i>Class A</i>	Rent in the top 30-40%, well located, above average upkeep and management. Prestigious and have state of the art systems, high quality finishes and definite market presence
<i>Class B</i>	Rents between Class A and C, fair to good locations, average upkeep and management, fair finishes and adequate systems
<i>Class C</i>	Rents in the bottom 10-2%, less desirable locations, below average upkeep and management. Competes for tenants looking for below average rents

Industrial:

Table 7. Industrial building types

Type	Description
<i>Heavy Manufacturing</i>	Heavily customized buildings with machinery required to produce goods and service
<i>Light Assembly</i>	Less customized and can be reconfigured, used for product assembly, storage and office space
<i>Warehouses and Distribution Centres</i>	Large buildings serving as storage and distribution centres

5.2. Residential Sector

Within the residential markets, the best segments for solar net-metering projects are the Multi-Unit Residential Buildings (MURBs) and Social Housing sectors. The single-family home market is not economically viable for solar net-metering at current rates. That may change and residential net-metering may become a more attractive option once BTM resources installed onsite (including DR and storage) can be aggregated.

5.2.1. Multi-unit Residential Buildings (MURBs)

MURBs have higher energy consumption levels that provide better scale and an opportunity to reduce costs. Low- and mid-rise MURBs typically have large roof areas suitable for the installation of solar arrays. Although it can cost more to install solar on flat roofs, they do offer the ability to set the optimal slope design of the panels to maximize production. Municipal affordable housing and housing co-operatives are more likely to consider the advantages of stable long-term leasing agreements.

MURBs can be categorized into rental apartments and affordable housing, or occupant owned buildings, such as condos and housing co-operatives. MURBs should also be further distinguished by whether or not they are serviced through a single bulk utility meter or if they are sub-metered to the level of a tenant unit.

Bulk metering uses a single meter for the entire property and usually means the landlord or property manager (PM) is paying the utility bill and recovering that cost through the rent. Solar leasing arrangements are simpler to implement in buildings with a bulk meter, as only one leasing arrangement with the landlord or PM is needed. Net-metering will allow the landlord or PM to improve their return on investment by capping or even reducing their operating costs. They can attract more tenants or buyers to their building by providing better rents and environmental benefits.

Another metering configuration which is becoming more common is a master meter for the entire property in conjunction with non-utility submeters to track individual unit consumption. The landlord or PM pays the utility bill and passes through charges to the tenants based on their individual consumption. With net-metering, the landlord or PM will allocate savings to individual occupants. This may be more acceptable in affordable housing, housing co-operatives or other social housing providers who have a mandate outside of earning a certain return on investment.

In individually metered buildings, the split-incentives problem can arise. This is quite common and a real barrier to investment - where the building owner pays for the capital investments but the tenants receive all the benefits in the form of reduced utility bills. This can potentially be overcome through the use of green leases, pioneered in Australia, which are based on the principle that whoever makes the investment should receive the benefits of the energy savings. (See **Appendix D** for more on split-incentives)

In buildings where the occupants are the unit owners such as housing co-operatives or condos, there is a further challenge as the co-op board or condo association approval would be needed.

The advent of virtual net-metering (the multi-party version) will make the administration and savings allocation for individual tenants much simpler and transparent.

5.2.2. Social Housing Providers

Social housing providers have stable long-term ownership, and some have large portfolios of buildings under a single owner. Many have capital constraints, limited operating budgets and housing stock in need of repair. This makes them good candidates for solar net-metering with third party financing.

Background

With the devolution of the responsibility of social housing provision from the Province to municipalities, Local Service Managers (LSMs) are responsible for the funding and administrative responsibilities of the *Social Housing Reform Act*. LSMs are the sole shareholders of the local housing corporations which are arm's length municipally-owned corporations that own and operate housing units throughout Ontario.

Alongside local housing corporations, housing co-operatives, non-profit housing providers and municipally owned housing provide social housing in Ontario. Private non-profit housing is typically developed and owned by community associations or charitable organization such as ethnic or religious groups. Special purpose groups are organized that accommodate seniors, people with disabilities and low-income households.

Housing Stock

There are 270,000 social housing units covering the entire range of building types in Ontario although low to high-rise apartment buildings as well as town or row houses are the most common. Social housing represents 5% of the total building stock in Ontario and 20% of the rental stock. Most of the social housing stock was developed after WWII and between 1964 and 1995. The majority of the stock is between 20 and 50 years old and in need of essential maintenance and capital replacements.

Capital Reserves, Funding and Operating Agreements

It is currently estimated that 70% of the social housing units in Ontario have a shortfall of capital reserves required for investments for capital repairs that is estimated at \$1.21 Billion. Under provincial and federal operating agreements social housing providers (SHPs) are required to maintain portfolios of rent-geared-to-income (RGI) units which prevents them from sharing higher costs of energy and mortgage debt service with their tenants⁷. A no-capital offering to deliver lower, stable long-term energy costs is ideal.

⁷ Institute on Municipal Finance and Governance. (2013). *Affordable Housing in Ontario: Mobilizing Private Capital in an Era of Public Constraint*.

Typically, many have deferred capital repairs that could reduce their operating costs, so solar net-metering is an attractive option.

Furthermore, federal operating agreements that provide subsidies to social housing to cover the difference between rent paid by low-income residents and operating expenses are being phased out over the next two decades. They are not being renewed based on the assumption that once the mortgages have matured, operating expenses should fall and affordable rents would be able to be offered without subsidy. As subsidies are tied to the mortgage terms, providers who are paying more to service their mortgage than they receive in subsidy should remain viable at the end of the mortgage, while those with high ratios of RGI and major capital repair needs will experience a funding gap. Research in BC has indicated that projects with more than 65% RGI units are unlikely to be financially viable post-expiry⁸.

Unlike other Canadian jurisdictions, responsibility for social housing was devolved to the municipalities in Ontario which made them responsible for administration of the federal funds. Under these agreements there is no sunset clause so the operating obligation of the provider and the subsidy obligation of the municipality will continue even after the federal subsidy has ceased at the end of the mortgage term. As government funding for repairs and upgrades and operating agreements comes to an end, and with the withdrawal of provincial money for GHG reductions in social housing the cost of capital repairs and renewal therefore are placed entirely on the municipality.

Social housing providers have indicated that they desire to increase environmental sustainability and energy efficiency but are often unsure of the options and necessary steps to evaluate those options⁹. Operational costs are often higher in social housing than in other housing. Net-metering represents an opportunity to control a significant operational cost. The cost of utility bills in Ontario for social housing is \$500 M per year¹⁰

5.2.2.1. Housing Co-ops

Housing co-operatives are an important potential partner for solar net-metering provided by RECs as there already exists shared co-operative values between them. There are 550 non-profit housing co-operatives across Ontario half of which were developed under federal operating agreements. They follow operating rules in an operating agreement with CMHC. The other half were developed under the provincial housing program when

⁸ BC Housing and BCNPHA, preparing for the expiry of operating agreements.

⁹ Review of effectiveness of investments in renewable energy for social and affordable housing.

¹⁰ Tsenkova, S. & Youssef, K. Energy efficiency retrofits: Policy solutions for sustainable social housing.

responsibilities were devolved, and follow operating rules outlined in the *Housing Services Act*, administered by municipal service managers¹¹.

Decision-making power in co-operatives lies with the board and most housing co-operative buildings are bulk metered. This means the path to a solar lease is should be easiest in this sector.

5.3. Institutional Sector

The owners of schools, hospitals, and government buildings provide the ideal customers that are most suitable for 20-year solar leases. They are also very receptive to the proposal of stabilizing energy costs and improved environmental factors. However, provincial procurement rules are often interpreted in a way that may hinder the optimal participation of co-operatives. Procurement rules generally adhere to best practice guidelines published by the Province; however, each institution writes their own rules and provides justification for it. The current norm is to hold competitive tenders to procure services above a certain value threshold. Some places provide exemptions from these rules for organizations with non-profit status. Non-profit co-operatives could potentially qualify under these rules.

Sector characteristics include:

- Have stable ownership and can tolerate payback periods over 10 years.
- Have limited debt loads
- Procurement rules may hinder new entrants from getting contracts
- Solar developers were already active in the MUSH sector in FIT era
- Public sector borrowers have access to low interest long-term debt rates

¹¹ Co-operative Housing in Ontario. <https://chfcanada.coop/your-region/ontario-region/about-ontario-region/co-operative-housing-in-ontario/>

6. Partnership Models

The RECs in Ontario see a vibrant future is community-owned renewable energy systems. While the short-term opportunities are emerging and gaining traction, they are largely one-off successes led by determined community champions. The really exciting opportunities will be unlocked by regulatory change to enable broader participation in neighbourhood development and aggregation. In this future, the key partners for RECs will be local LDCs, local Municipalities, and technology service providers.

LDCs

The Electricity Distributors Association (EDA) recognizes that the traditional roles and responsibilities of its member LDCs need to evolve to support the industry landscape of the future. LDCs are confronted with greater demand for the integration of distributed energy resources (DERs) such as solar, wind, and energy storage, as well as other technologies such as electric vehicle (EV) charging infrastructure, demand response (DR), and conservation and demand management (CDM).

A survey conducted in 2016 has indicated that nearly all LDCs surveyed expressed the desire to expand their businesses with interests ranging from shared service models, to joint ventures and new lines of business with their unregulated affiliates¹². However, the number one barrier cited is regulatory ambiguity and challenges around LDC ownership and operation of DER.

In February 2017, the association proposed a visionary framework for LDC transformation through three dimensions:

1. Development of an intelligent platform for DER integration in LDC systems;
2. Allowing LDC ownership of DERs; and
3. Optimizing Local grid control to coordinate usage of DERs.

Once implemented, these changes will unleash a province-wide tidal wave of innovation and investment in local community energy systems. RECs and LDCs could co-own generation facilities; RECs could supply grid services through BTM aggregation; local REC-owned energy storage could participate as a Virtual Power Plant at community scale; the list seems endless.

¹² Electricity Distributor's Association. (2017). The power to connect: Advancing customer-driven electricity solutions for Ontario.

In the early days under the FIT program, LDCs were often seen as the enemy by RECs whose projects encountered technical, administrative and policy barriers. RECs should now power-up their considerable community engagement capabilities to mobilize support for the 'new LDC' vision. The REC collaborative approach can bring the local neighbourhood model to fruition but only if the emerging LDC systems are designed to handle that level of granularity.

Local Municipalities

Local town councils are on the front lines of the clean energy revolution, whether they are ready for it or not. Local citizens are demanding action, not words or excuses. The federal infrastructure program puts an \$11B budget at their disposal, but only for qualifying local projects that they take leadership and ownership. They need help.

By focusing on neighbourhoods to concentrate their impact, RECs can engage local community associations, local BIA organizations and the local councillor. City-owned properties must be included in the collective vision – they meet the ideal customer criteria for solar net-metering.

Most of the LDCs are municipally-owned. There is a latent powerful business model that could be jolted into action by enlisting them as partners in a REC-led neighbourhood-level clean energy plan. The TRCA in Toronto has created highly successful action plans for sustainable neighbourhoods called SNAPs. RECs with LDC and Municipal council support can adapt and harness those successful models for the energy revolution.

The RECs are able to fulfill the key roles of project origination and project finance. Building community support starts with a concrete idea and a concrete timeline. Mobilizing municipal council support takes longer but needs the same starting foundation.

Technology Providers

As the costs for solar and storage continue to plummet, new applications for clean energy are emerging at a rapid pace. The economic barriers are being pressured at both ends of the scale – scaling up to larger and more powerful projects, and scaling down to fit into smaller but vastly more plentiful niche applications. The constant challenge is to integrate and operate these diverse elements as a reliable, financially viable business.

Each successful REC project has relied to some extent on proven technology partners, whether acting as designers, installers, maintainers or consultants. RECs are not well positioned to take on higher risk, unproven or early 'pilot' projects. Yet RECs offer the technology provider a ready-made distribution channel to market once the product is ready for prime time. It is to their advantage to work with the REC from the outset to

build community support for their new products through meaningful engagement. eCamions pole-mounted battery energy storage systems are one example of a small-scale, distributed technology that RECs could implement once it has become commercialized.

The Alectra PowerHouse (solar plus storage) project is a perfect example of a neighbourhood initiative that would benefit from a local REC's involvement. This 20-home pilot project (called a Virtual Power Plant) was designed to study the benefits of aggregating BTM storage. Those benefits accrue both to the LDC grid reliability and to the 20 homeowners. Imagine the level of impact by aggregating 20 community-scale projects.

In the longer term, there will likely be a local market for ancillary grid services, such as voltage & frequency regulation. Battery storage (at scale) is able to deliver these services on top of their primary function of storing and releasing energy on demand. By developing neighbourhood scale solar plus storage, RECS may be able to offer these services as well.

BTM Aggregation

Under the 100-year old regulatory model, the 'meter' is the defining demarcation point. Utility operators are licensed in front of the meter; load customers consume power behind the meter. For anticipated BTM aggregation services, the LDC would prefer to have a contractual relationship with a small number of entities, who act on behalf of the community, rather than signing agreements with each and every individual building owner and every tenant. Allocation of credits will fall to the REC, acting as the aggregator.

First Nations Communities

First Nations communities in Ontario and across Canada are increasingly developing RE projects in their communities. This is of particular importance in northern communities that rely primarily on diesel generation which is subject to high transportation costs and can constitute a large portion of budgets allocated to education and other services. Solar and storage projects in these communities are freeing up money which can then be used for other needs. There is an opportunity here for RECs to share their experience with solar and community financing to help facilitate more of these projects.

Matawa First Nations Management is a tribal council with nine member Ojibway and Cree First Nations with communities throughout Ontario. They are currently developing a consortium of companies to deliver a full range of energy services in their communities including solar plus storage and microgrids. They have expressed interest in RECs in Ontario playing a role in this consortium to aid in project development and financing.

7. Core Competencies

This section outlines the core competencies (Figure 6) that RECs will need to operate a solar and energy storage business. One organization may not possess all these competencies, highlighting the significance of developing partnerships. The most important competency will be to establish credibility and a successful track record. This primer addresses many of these competencies, however, RECs will still need to conduct their own research to understand the specific local market contexts.



Figure 6. Core competencies to operate an energy storage businesses

8. Business Model Canvas

Option #1 - Solar and/or Storage Equipment Leasing

Option	Solar and/or Storage Equipment Leasing	
Key Activities	Lease equipment to consumer- solar + storage or solar only. Consumer remains generator for regulatory purposes, allowing net-metering (NM) credits to be obtained. Stand-alone storage not allowed for NM purposes so must be built in conjunction with solar or added to already installed solar systems.	
Key Partners	<ul style="list-style-type: none"> • Solar and storage equipment and technology providers • LDCs for net-metering, and connection 	
Customer Segments	<ul style="list-style-type: none"> • Aggregated single-family homes • MURBs • Commercial and institutional sector 	
Value Proposition	<ul style="list-style-type: none"> • Involvement of co-operatives in NM business demonstrates to the provincial government the capacities and willingness of the co-operative in support of opening up 3rd party NM. • No money down for customer, and all O&M provided. • No project development or construction risk for customer. • Addition of storage opens up potential for more revenue streams and value of backup power. 	
Financial Model		
The co-operative can raise upfront costs and construction financing from community bonds; however, this is a riskier option for investors than offering bonds post-commercial operation. Construction financing can be obtained as a loan from a project financier. If partnered with a municipality, or social housing provider, grants may be available to offset the upfront costs. The co-operative themselves can install the systems or contract out for installation.		
Leasing Models	Full ownership	Customer buys own equipment.
	Lease	Co-op leases equipment to customer and receives monthly lease payments based on expected production of system. Co-op owns the equipment.
	Loan	Co-op gives loan to customer. Customer makes fixed monthly loan payments. Customer owns the equipment.
	PPA	Customer pays co-operative per kWh generated.

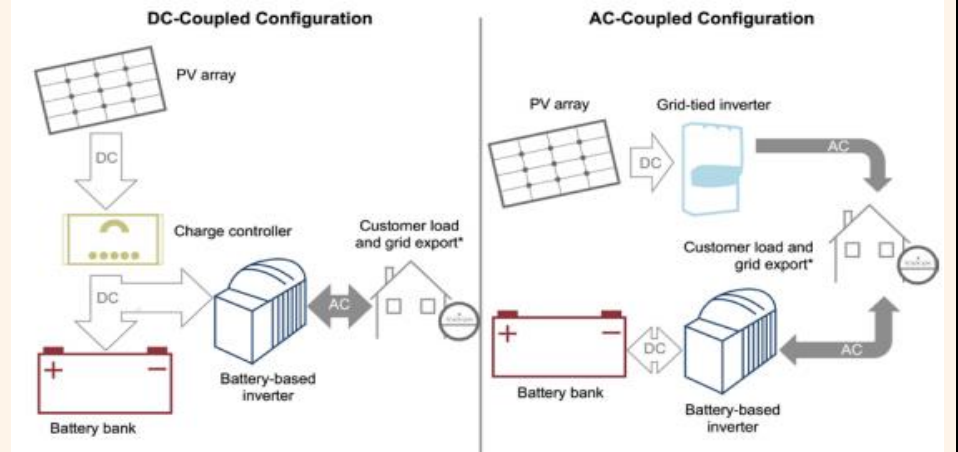
Revenue Streams	
Solar Only	Customer receives NM credits and makes monthly payments to the co-operative based on expected production of the system under a lease or loan model. Payments should ideally be equal to or less than the value of the NM credits in order to generate positive cash flows for the customer.
Solar plus storage	Residential storage and solar for net-metering is not currently economically feasible because LDC switches customer from TOU to tiered rates with net-metering, which reduces the revenue streams from the battery operation such as load shifting and arbitrage as there is no cheaper off-peak time the storage system can charge from. This section will describe which revenue streams are enabled for residential solar plus storage if enabling regulations and policies are put in place.
TOU Optimization	<p>Charge battery from solar during off-peak and discharge into the grid during on-peak times to maximize value of NM credits.</p> <ul style="list-style-type: none"> ● Enabling legislation: TOU billing for NM customers. Utilities may oppose charging residential batteries from the grid and selling power back to the utility for a higher price. Regulations that limit batteries to only be charged from the customers solar panels may be needed. ● Potential TOU Operating Strategy: Solar production meets generators consumption first, excess production is fed into grid to obtain net-metering credits when prices are high. Charges battery from grid or excess solar when prices are low. Battery feeds into the grid during on-peak and mid-peak hours (7am to 7pm) to get higher value NM credits or meets customer loads if solar production is insufficient. Can retain a certain level of reserve in the battery for backup power. Battery charges during off-peak hours from the grid and from any solar generation (7pm to 7am).
Increasing Self-Consumption	<ul style="list-style-type: none"> ● Revenue comes from offsetting of utility bill. System is sized so no consumption from grid is needed. May still have to pay fixed charges if still connected to grid. Sizing system big enough for grid defection may not make financial sense compared to net-metering. An average home in Ontario uses 10,000 kWh per year, so will need a 10kW peak system. With costs at \$2.50 per W, the capital costs for a 10kW system would be around \$25,000. With hydro bills being \$100 to \$300, payback ranges from 20 to 7 years. Grid defection makes the most sense for remote locations with no grid access or where paying for a new utility line is needed, although current payback periods may already be in the acceptable range for those that have high energy bills.

Cost Structure

Equipment

- PV array, battery and battery-based inverter.
- DC coupled system= charge controller to step down PV voltage output to safe levels for battery, can decrease overall PV efficiency, but is more efficient in applications where the customer more frequently stores PV output rather than consumes it.
- AC coupled system= grid-tied inverters to feed PV output directly to customer load or grid. Can achieve higher PV system efficiency in applications where PV output is more frequently consumed at the time of generation.
- Bidirectional inverters only required if battery will charge from an AC source (e.g. backup generator, the grid).
- Battery based inverters are less efficient for PV consumption applications even if charge controller is removed.

Configuration of DC and AC Coupled Systems



Soft Costs

- Permitting, inspection and interconnection costs.
- Operating optimization software.

Case Studies

SolShare

- Subsidiary of the Vancouver Renewable Energy Co-operative.
- Residents purchase shares and receive dividends from lease payments generated from solar panels.
- The generated solar power is not sold to the utility but is sold directly to the owner of the building through the lease agreement. The electricity is priced at a premium compared to standard electricity rates but is similar to other green power premiums.

	<ul style="list-style-type: none"> Leases are 5 to 10-year contracts. Escalates each year with utility prices but never more than 50% of the utility rate increase. Option to renew at the end of the contract. If not renewed, then PV system is removed. VREC takes on all project development and construction cost and risk and sells panels to Solshare after commissioning. Shares are offered periodically as new projects are developed.
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Option #2 - Solar and Storage Aggregation

Option	Solar & Storage Aggregation
Key Activities	Co-op finances and/or installs solar plus storage, or storage only. LDC or third-party company can control aggregated resources to deliver grid services and backup power.
Key Partners	LDC aggregates and controls storage through smart software to maximize benefit to generator and provide grid services or these services could be contracted out to a third-party.
Customer Segments	BTM aggregation is typically referenced in relation to single-family homes, however any building with proper site characteristics can have BTM solar and storage installed.
Value Proposition	<ul style="list-style-type: none"> Co-op aggregation reduces transaction costs for LDC. Provides grid services. Backup power, NM revenue and ancillary market revenue for homeowners. Addresses challenge of finding suitable locations for energy storage.
Financial Model	
Debt Instruments & Grants	<ul style="list-style-type: none"> Upfront costs raised through debt instruments and grants. Community bonds can be used to raise upfront capital but will be riskier than offering bonds in after commercial operation.
Leasing Models	<ul style="list-style-type: none"> Co-op leases solar + storage systems to homeowners. LDC or third-party company operates the assets to maximize benefit to homeowner through net-metering, back up power and provision of grid services. A contract would stipulate how proceeds from operation of the storage system would be allocated to stakeholders.
Revenue Streams	

Revenue streams depend on the use cases that can be taken advantage of by the storage systems. The NREL identifies 13 different revenue streams that can potentially be captured by energy storage (see tables below). In the US, where the storage market is more developed only four or five of these revenue streams are actually realized: demand charge management, BTM, utility scale solar plus storage (ramp rate regulation), frequency regulation and demand response. In Ontario access to revenue streams from IESO ancillary markets are limited as the IESO is not currently procuring for these programs (See description of ancillary markets below). High-level design documents released by the IESO have indicated that aggregated distributed energy resources such as BTM energy storage, and demand response will be able to participate in the incremental capacity auction and/or demand response auctions from 2020 onwards. The minimum aggregate capacity needed to participate in the IESO markets is 1 MW. Additionally, aggregated generation resources must be connected to the IESO controlled grid at the same connection point, must be under operational control of a single market entity, have sufficient metering for settlement purposes and meet IESO operational communication requirements between each of the facilities.

Opportunities for Income from energy storage

Service	Description	Potential Value	Grid Scale	Commercial Scale	Residential Scale
Demand response	Storage used to support participation in utility programs that pay customers to lower demand during system peaks	High		✓	✓
Frequency regulation	Stabilizes frequency on moment-to-moment basis	High	✓	✓	
Reserve markets	Supply spinning, non-spinning reserves	Medium	✓	✓	
Black start	Helps restore system to operations after a blackout	Low	✓		
Voltage support	Inserts or absorbs reactive power to maintain voltage within required ranges on distribution or transmission system	Low	✓		

Energy storage opportunities for cost and loss avoidance

Service	Description	Potential Value	Grid Scale	Commercial Scale	Residential Scale
Demand-charge reduction	Uses stored energy to level peaks in load to reduce demand charges on utility bills	High		✓	✓ (Limited locations)
Time-of-use bill reduction	Uses storage to shift the time self-generated electricity is used onsite to reduce grid purchases when electricity costs are high	High		✓	✓
Energy arbitrage	Stores energy when grid prices are low then sells it when grid prices are high (high value in real-time markets, low value in hourly markets)	High	✓	✓	
Resiliency and back-up power	Uses battery to sustain critical loads during grid outages	High	✓	✓	✓
Avoided renewable energy curtailment and increased self-consumption	System owners avoid curtailing their own renewable generation when system load is low and renewable generation is high	Medium	✓	✓	✓
Supply capacity and resource adequacy	Uses storage to meet peak-load growth and defer need for new generating capacity	Site Specific		✓	
Transmission and distribution upgrade deferral	Defers the need for transmission or distribution system upgrades (e.g., via utility system-peak shaving)	Site Specific		✓	
Transmission congestion relief	Utilities can avoid extra transmission charges from Independent System Operators during times of congestion by deploying strategically located storage	Site Specific		✓	

<p>How the revenue streams are divided between stakeholders depends on the governance model and the agreed upon revenue or service sharing agreement as well as the operating strategy. Some possible arrangements are outlined below:</p> <ol style="list-style-type: none"> 1. Co-op owns and operates equipment. Development and operation of software for the storage system is contracted out to a third-party. <ul style="list-style-type: none"> ○ Co-op Revenue: lease payments and revenue from grid services and ancillary markets. ○ Customer: energy bill savings, NM, revenue sharing, backup power. 2. Co-op owns, LDC operates. <ul style="list-style-type: none"> ○ Revenue sharing agreements split revenue from grid services and ancillary markets. ○ Homeowners: energy bill savings, NM, revenue sharing, backup power. 	
<p><i>Potential aggregation operating strategy</i></p>	<ol style="list-style-type: none"> 1.) Solar production meets consumption; 2.) Excess is used to charge battery, if TOU pricing is enabled battery can charge from grid during off-peak; 3.) After battery is charged excess solar is fed into the grid for net-metering; 4.) Battery can discharge for net-metering credits or be used by the LDC for DR, peak shaving, or can be bid into markets for frequency regulation, voltage control, and operating reserve markets, ensuring that a minimum level is left for backup power.
<p><i>Behind-the-Meter</i></p>	<p>For equipment leasing models with storage installed behind-the-meter, as described above, the revenue streams come from periodic payments from the customer and from the resulting energy savings. If these assets can then be aggregated within a LDCs service area additional revenue streams can be opened up by contracting with the LDC for the provision of distribution grid services or through participation in ancillary or capacity markets. In a lease model where an energy storage company owns and operates the assets on behalf of the customer and guarantees them a certain level of utility bill savings, as long as this level of savings is maintained it is possible to make the case to homeowners who have these assets installed in their building to use the aggregated storage network for other use cases.</p>
<p><i>Front-of-Meter</i></p>	<p>If a front-of-meter storage system installed in the distribution grid is owned by the community similar revenue streams as BTM are opened up, except less focus would be placed on optimizing the energy savings of individual households and the system would draw on revenue streams from the LDC and ancillary markets, and provide community services such as backup power or EV charging.</p>

<p><i>Transmission Grid</i></p>	<p>A system installed in the transmission grid provides services similar to a system installed in the distribution grid such as transmission congestion management and transmission grid deferral, as well as being able to participate in the ancillary markets and provide other benefits such as ramp rate regulation for transmission grid connected RE projects and load time shifting. While co-operatives could develop such systems, the battery would not provide direct services to the community and is at a larger scale than co-operatives normally operate at.</p>
<p>Cost Structure</p>	
<ul style="list-style-type: none"> ● <i>PV array, battery and battery-based inverter.</i> ● Permitting, inspection and interconnection. ● Development & optimization of control software. 	
<p>Case Studies</p>	
<p>Vermont Green Mountain Power</p>	<ul style="list-style-type: none"> ● Utility installed 2000 Powerwalls in customer homes. ● Customers pay \$15 a month for 10 years for a Powerwall or a \$1,500 one-time fee. ● Cost of Powerwall plus installation is \$8,800 so required \$8 million-dollar investment by utility. ● Customers can charge it from already existing solar panels or from the grid. Excess solar generation is provided to the grid for credit. To be used for backup power while the utility accesses it during periods of peak demand to lower peak rates. ● Can supply entire home’s power for 12 hours and can continuously supply 5 kW or provide up to 7 kW at peak demand. ● Potential to reduce peak load by 10MW. ● Provided equivalent of taking 6,000 homes off the grid during peak demand. Saved \$500,000 in one week when storage was dispatched during heat wave. ● Anticipated returns of over \$2 to \$3 million. ● Working to dispatch into wholesale electricity market.
<p>Alectra Power.House</p>	<ul style="list-style-type: none"> ● Large homes: 5 kW solar; 11.6 kWh storage; \$4,500 upfront or \$80 per month for ten years; 4 to 5-year payback. ● Small homes: 3 kW solar; 7.7 kWh storage; \$3,400 upfront or \$55/month for 10 years; 5 to 6-year payback. ● 20 homes total. ● Revenue streams: TOU arbitrage and NM for customers, ancillary markets, DR and offsetting of grid investments for LDC. ● Average customer savings= \$142/month.

Southern California Edison	<ul style="list-style-type: none"> • 3,000-unit home storage fleet. • Swell Energy and Autogrid partnered with Southern California Edison to deliver 20 MWh of storage across 3,000 homes: Swell provides solar/battery packages, Autogrid developed operation software. • Basic 2.1 kW of solar with 6 kWh of storage (enough to power a kitchen and internet during a blackout) priced at \$32.41USD per month. High-end package = 6 kW of solar, with 25 kWh of storage (enough to run whole house off grid) priced at \$74.56USD per month. • Price is brought down by leveraging contracted revenue streams to utility: Systems must be ready to deliver with 15 minutes warning to deliver 5 MW for a 4-hour continuous period, managed by Swell. • \$40 million fund to rollout the systems. • Payback for upfront purchase of system is 10 years; lease payments will be at least partially covered by offsetting utility bill and provision of grid services. Revenue sharing is contracted upfront with customers.
Glasgow Electric Plant Board- Kentucky- Storage Only	<ul style="list-style-type: none"> • Rural community, population 14,000. • Energy Storage Installed in 165 homes by Sunverge, no solar. • Storage units aggregated by system operator, charged at night when prices are low and discharged during the day to offset use of peaker plants saving money and reducing emissions. • Also provides backup power to homeowners.

Option #3 - Centralized community energy storage system

Option	Centralized community energy storage system
Key Activities	Centralized distribution-connected storage system to provides grid services for the LDC and could potentially be co-located with a solar array to charge the battery. Depending on how it is connected it could be used for backup power to certain buildings or could be used for EV charging in the community.
Key Partners	<ul style="list-style-type: none"> • LDC • Municipality
Customer Segments	<ul style="list-style-type: none"> • LDC • Residents • Businesses

Value Proposition	<ul style="list-style-type: none"> ● If LDC distribution lines are at capacity, no additional generation can be added. Addition of storage solution at a feeder opens up capacity enabling greater DG uptake. Important to allow net-metering. For example, Niagara-on-the-lake is experiencing a growth in generation but not load. Storage can provide additional load to offtake surplus generation. ● Demand response, peak shaving, offset grid investments, backup power.
Financial Model	
<i>Co-op finances through community bonds or debt financing</i>	Co-op owns but LDC operates to take advantage of grid services, ensuring backup power is available. Co-op receives payment on investment from ancillary markets or from LDC for provision of grid services.
<i>Co-op finances and leases back to the LDC</i>	LDC operates with option to own at end of lease period. Co-op retains value of backup power.
<i>Co-op and LDC jointly finances</i>	Third party operates to provide grid services to the LDC and backup power to the co-op.
Revenue Streams	
<i>participation in IESO ancillary markets</i>	Revenue from participation in IESO ancillary markets can be used to repay investors.
Arbitrage	
Peak shaving	reduced peak demand charges.
Cost Structure	
<ul style="list-style-type: none"> ● Feasibility study ● Equipment purchasing ● Cost of land and siting ● Cost of interconnection ● Control software development ● IESO market participation fees ● Frequency regulation down: project owner must pay for losses when charging 	

Case Studies	
North York Community Energy Storage (CES)	<ul style="list-style-type: none"> ● Consortium led by eCamion with Toronto Hydro-Electric, UofT, and Dow Kokam LLC. ● 250 kWh/500 kW located at Roding Arena Community Centre North York. ● Funded by the consortium and Sustainable Development Technology Canada. ● Installed at the customer level not at station level. ● Regulates power flow to reduce overloads, peaks and improves power quality, provides backup power. ● Control system monitors grid conditions to charge during off-peak and discharge on-peak. ● Battery management system controls charging and discharging. ● Can provide grid support for 150 homes or a cluster of level 2 and 3 EV charging stations.
Niagara-on-the-Lake	<p>Niagara-On-The-Lake Hydro will install a battery to make capacity available at a specific feeder and enable greater distributed energy resource uptake, analyzing performance to confirm optimal use. The presence of the battery will allow for more customers to participate in renewable generation and net metering in the area.</p>

Appendix A: What are Distributed Energy Resources?

A DER can be defined as any resource that is connected to the distribution grid, rather than the transmission grid, or is located BTM on an end-user's property¹³. They provide the ability to generate, store or adjust electricity consumption. **Figure 7** provides an overview of the different types of DERs connected to a distribution system. Types of DERs include:

- *Distributed generation*: small electricity generating units located FTM in the distribution grid;
- *Behind-the-meter generation (BTM)*: generating units located on the customer's side of the meter; Solar PV is the primary renewable energy technology utilized for this application due to its increasingly low cost and relative simplicity in implementation. Other types of generation include small scale diesel or gas generators and combined heat and power generators. BTM battery storage is sometimes referred to as BTM generation because it produces electricity as well as consuming it, however, for clarity it is referred to here as a separate category.
- *Electric storage*: batteries and other devices capable of receiving electricity, storing it, and later discharging it back to the grid. Lithium-ion batteries are currently the most widely used type of battery due to their high efficiency and response times.
- *Demand-side management*: practices and activities that have the effect of reducing demand for electricity (load). These include demand response, whereby customers reduce their electricity usage during peak periods in response to price increases or incentive payments, whether by foregoing that usage altogether or by shifting it to off-peak periods.

¹³ Gundlach, J. and Webb, R.. (2018). Distributed energy resource participation in wholesale markets. *Energy Law Journal*, 39 (1).

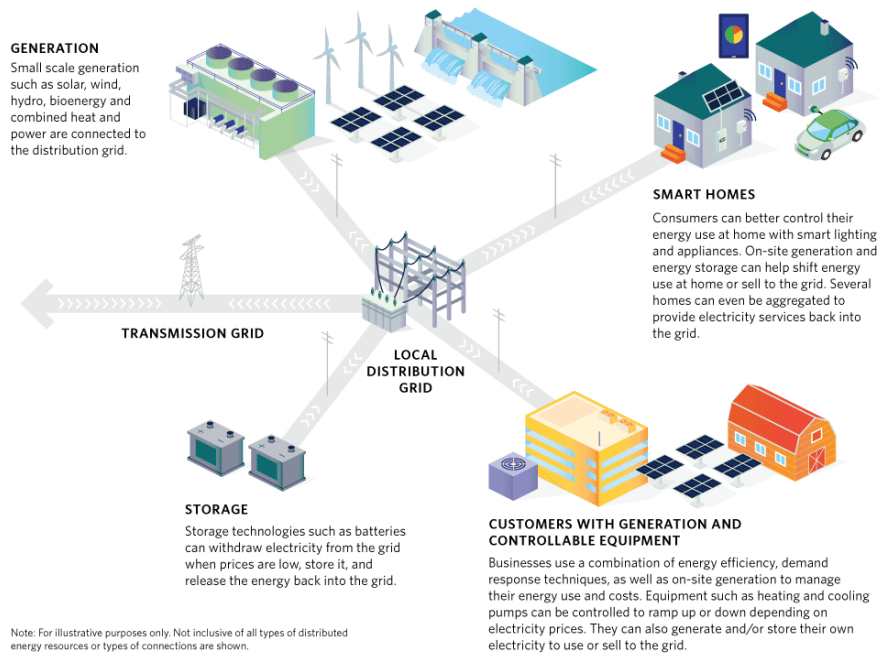


Figure 7. Range of DERs in a distribution grid¹⁴

For co-operatives , BTM solar and battery energy storage (BES) are the most relevant in Ontario’s current regulatory and policy framework. They are also the most scalable and affordable out of the electric energy storage technology options. Other than energy efficiency in buildings, demand-side management opportunities are currently limited, although there may be opportunities for co-operatives to aggregate community loads to participate as demand response in the new capacity market being proposed for 2020, or in further ancillary market procurements.

¹⁴ IESO. (2018). Momentum grows for a more networked, decentralized energy system in Ontario and globally.

Appendix B: IESO Ancillary Markets

Ancillary markets are contracted services provided through a procurement market that are required to maintain the reliability of the grid. The IESO ancillary markets will be an important market segment for storage to provide its full range of potential services and become more economically viable. This section provides an overview of the IESO ancillary markets that energy storage could participate in if the IESO runs more procurement programs. Energy storage devices are currently only participating in the regulation and reactive support and voltage control markets.

Black Start: Ability to restart a generation facility without outside power. Black start facilities are called on to re-energize parts of the system in the event of a blackout. Receives fixed monthly payments and must undergo annual and monthly testing with payment penalty of testing is failed.

Barriers: No plans for additional black start procurement

Regulation service: Matches total system generation to total system load including transmission losses, and controls power system frequency. Corrects for short-term changes in electricity. Facilities vary output automatically in response to Automated Generation Control Signals (AGC). Traditionally provided by synchronous generators; currently two energy storage facilities provide regulation service. Minimum of 100 MW has to be scheduled at all times. Overall ramp rate has to be 50 MW/minute. Individual resources may have a ramp rate below this but must meet this threshold collectively. IESO looking to procure additional regulation service to be able to schedule 250 - 300 MW on an as-needed-basis by 2020.

The previous RFP did not allow aggregated BTM resources to participate as facilities are required to be individually metered. Receive payment for service provided and amount of energy injected in the grid- fixed availability payment plus variable payment. Generators are also allowed to offer incremental capacity into the energy market, but not allowed to participate in the operating reserve market during hours they are providing regulation service. Energy consumed during provision of regulation is exempt from the GA.

Barriers: Storage is energy-limited, meaning there may be times when regulation is needed but the storage system cannot provide regulation up or down because it is empty or full. Nevertheless, regulation markets are currently the primary revenue stream for energy storage.

Reactive support and voltage control: Allows IESO to maintain levels of reactive power and voltage levels on the grid. All generators injecting energy into the grid are required to provide reactive support and voltage control. Payments are made based on the cost of providing reactive power including the cost of energy losses when providing reactive power. According to NERC rules the IESO shall operate each generator in automatic voltage control mode

Operating Reserve:

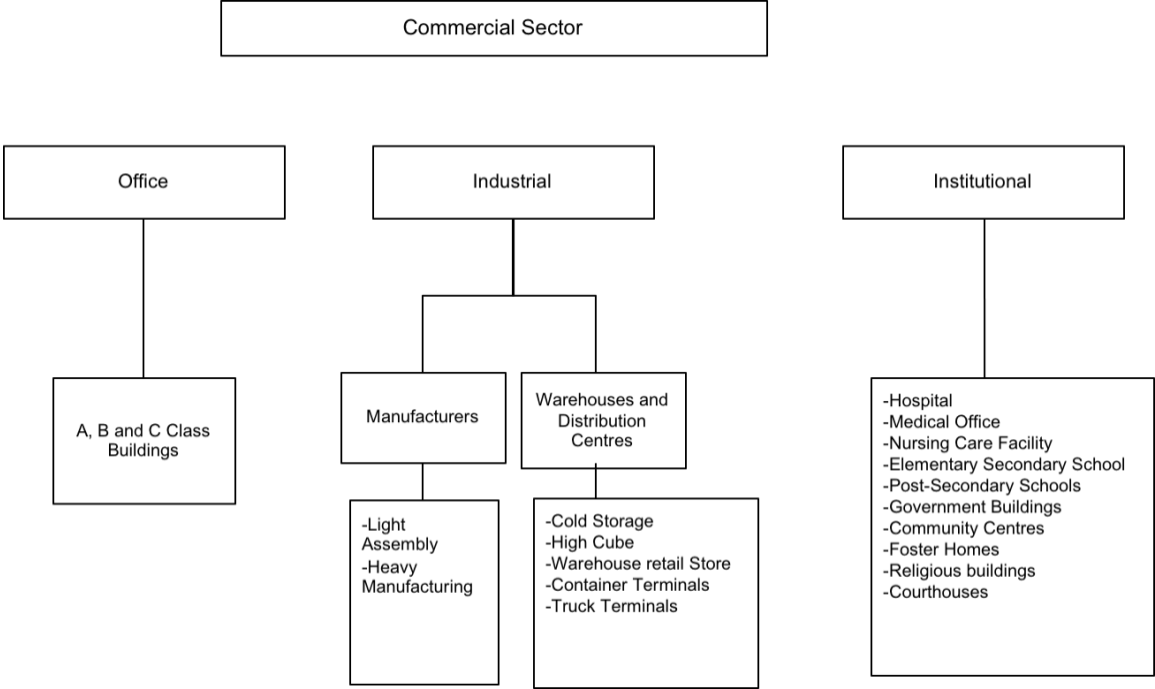
Stand-by power or demand response that can be called upon with short notice deal with mismatch between load and generation. Three classes include:

- 10-minute spinning- on-line reserve capacity; first type used and is synchronized to the grid to maintain system frequency
- 10-minute non-spinning- off-line reserve capacity that can be ramped and synchronized within 10 minutes
- 30-minute reserve

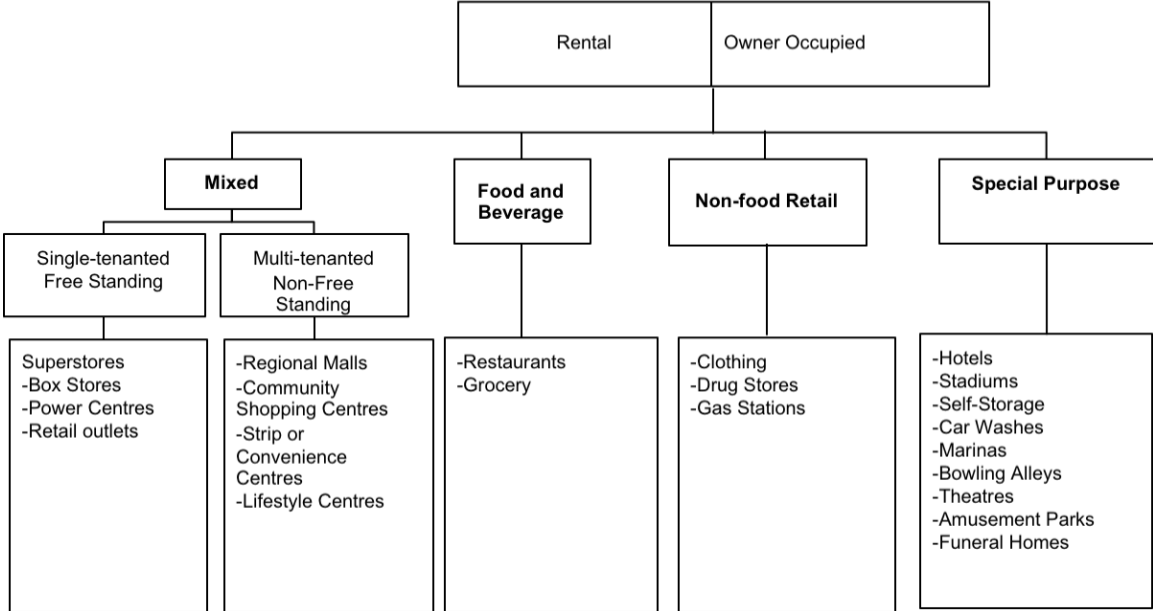
Generators must be able to offer service within the timeframe specified for a duration of one hour. To offer into the operating reserve the generator must be able to offer greater or equal amounts into the real-time market. Participants can offer into all classes and can receive standby payments for each. Price is determined every 5 minutes based on offers into the market. All selected suppliers are paid the market clearing price.

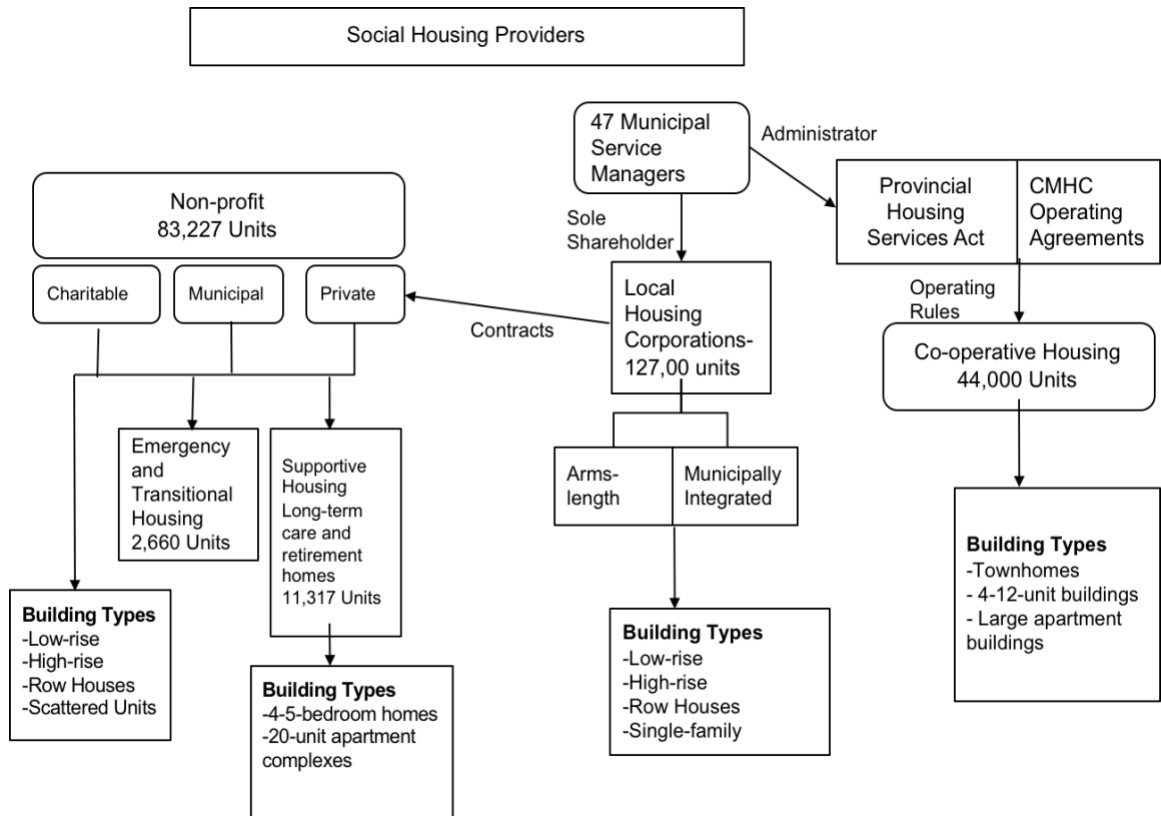
Barriers: Storage may not be able to always offer into the real-time market in order to participate due to not enough charge.

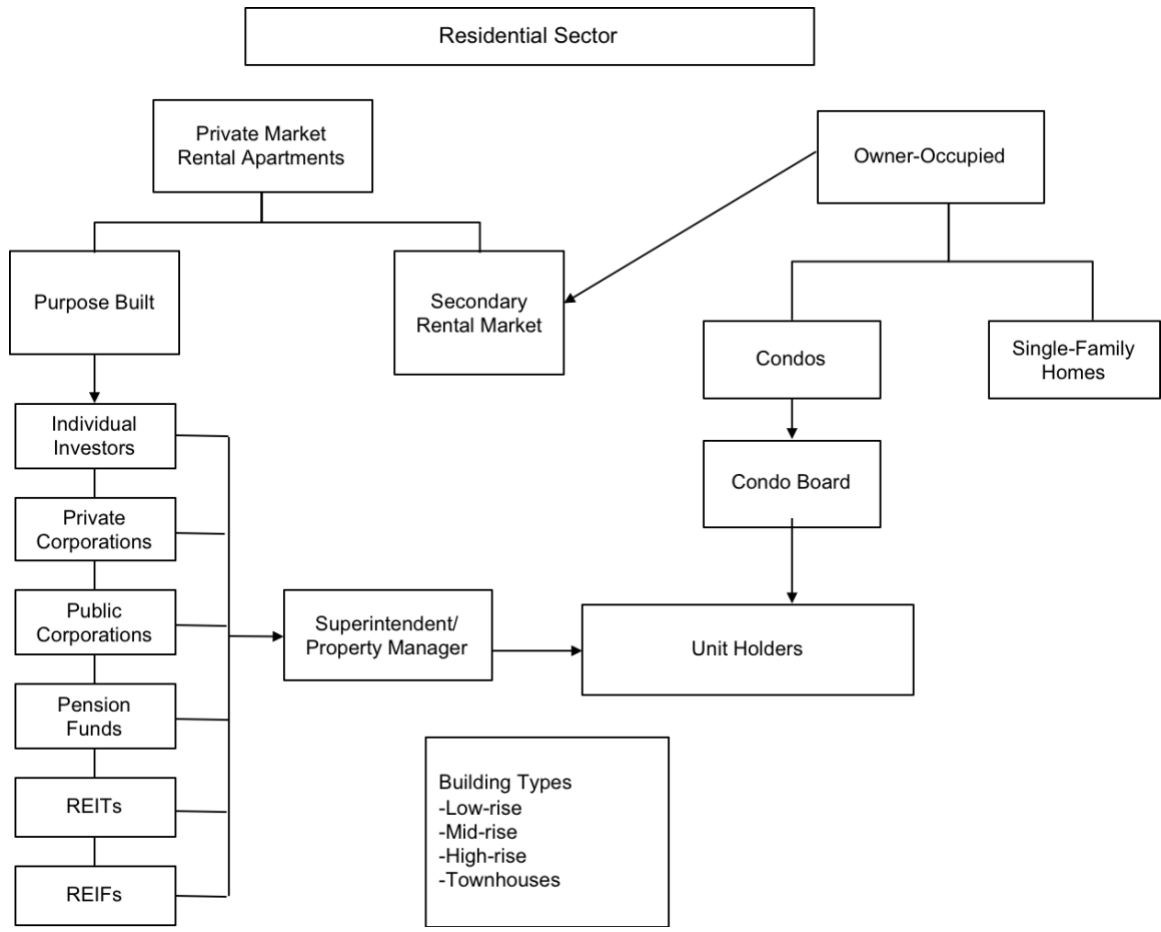
Appendix C: Market Segment Maps



Commercial Sector - Retail







Appendix D: The Split Incentive Problem

A split incentive is any situation where benefits of a transaction does not accrue to the actor who pays for the transaction¹⁵. In the context of EE, the split incentive has to do with a mismatch between who makes the capital investment and who accrues the benefits, which can ultimately result in inaction. Investment costs of EE are part of capital expenses whereas the financial benefit occurs in the form of reduced energy bills on the operational expenses. Therefore, if the actor in charge of capital expenses (the building owner) is not the same as the actor who receives the financial benefits (the tenant) a split incentive arises. The different types of split incentives are as follows:

Efficiency-related split incentives (ESI): An ESI occurs when the end user pays the energy bill but has limited power in their ability to choose the technology needed to improve EE. The landlord-tenant dilemma in rental housing and commercial leasing is an example of this. In these cases, the building owner lacks the incentive to invest because they will not reap the benefits of the energy savings and often cannot capitalize the upgrades into higher rents due to uncertainty over the impact of the upgrade on the property value and lack of experience on rent premiums¹⁶. ESIs can also occur in new builds where the property developer's main concern is to reduce construction costs and does not have an incentive to invest in measures that will reduce the operating cost of the building when it is sold to a new owner. Although, there is marketing value to this.

Usage-related split incentives (USI): USIs occur when occupants are not responsible for paying their utility bills and therefore have no incentive to conserve energy.

Multi-tenant, multi-owner split incentives (MSI): MSIs occurs in building with multiple owners or tenants such as condominiums where EE projects can only be realized if consensus between all decision-making parties can be reached. The occurrence of this problem depends on if EE improvements are proposed for the entire building or just for common elements.

Temporal Split Incentive (TSI): TSIs occur when the EE investment does not pay off before the property is transferred to the next owner or occupant.

¹⁵ European Commission. (2017). Overcoming the split incentive barrier in the building sector. JRC Technical Reports.

¹⁶ European Commission. (2017). Overcoming the split incentive barrier in the building sector. JRC Technical Reports.

To bypass the split-incentive problem EE retrofits can be targeted at common areas, which requires dealing only with the co-operative or condo boards rather than individual unit holders. This also reduces transaction costs and does not require consensus of all the unit holders. This provides a good starting point for RE co-operatives new to the EE business due to the easier implementation.

Overcoming the split-incentive problem requires a more complex approach and for agreement to be reached between the landlord and tenants. In Ontario, the USI and TSI problems are the most common as most MURBs are bulk metered, meaning that there is one meter for the entire property putting the responsibility on the building owner to pay the utility bills. The building owner can recover these costs through the rent or can sub-meter individual units to better allocate costs per individual usage. Bulk metering may make it slightly easier to implement EE retrofits in these buildings as the building owner can reduce operational costs and improve their ROI, and value of their property. However, in the long-term a change to individual metering is needed in order to develop innovative rental structures to encourage EE upgrades. Individual metering usually results in reduced energy consumption as occupants receive direct feedback on their consumption which can alter habits, whereas in a bulk-metered building, the tenant does not have any financial incentive to implement behavioural changes that may be required by the newly installed equipment to maximize the savings potential.

Individual meters can also make the ESPC process easier by allowing easier and more detailed monitoring of performance to establish baselines based on actual performance rather than predicted performance. With direct feedback from the meters, the landlord and tenant can agree upon a set of comfort conditions such as indoor temperature in the winter. All costs of energy could be included in the rent but the direct feedback would allow the tenant to be compensated if they consume less or pay more if they exceed the pre-set consumption levels. Other solutions to the split-incentive problem need to occur at the regulatory level such as minimum performance levels in rented units, revisions in rent and condominium acts, and energy labeling.

Appendix E: Key Considerations in Leasing Contracts

Transparency and clarity in lease terms are important to ensure the customer understands the full implications of the lease. Key terms include:

Buyout Options

Many lease contracts allow the lessee to pay off the remainder of the payments in one lump sum or to buy the system at fair market value. The contract should stipulate under what circumstances a buyout can happen (i.e. after what period of time?) and how the price is calculated.

Contract Term

This states the length of the term and what options are available at the end of the contract. Typical options include contract renewal, purchase the system outright for its remaining value, have the lessor remove the system.

Credit Requirement

Most third-party financing arrangements require a credit score of 680 or higher.

Down Payment

Some contracts allow for an initial down payment to be made that can reduce the monthly payments, shorten the contract term, or waive the escalation clause

Escalation Clause

To account for inflation many contracts contain an escalation clause at an annual rate of 1 to 3%. This is usually below the average annual increase of electricity rates which is 3 to 4%

Ownership Transfer Provisions

Contracts usually allow the transfer of leases or PPAs to the next owner in the event of a change in building ownership provided the new owner wishes to undertake the lease and has a sufficient credit score. Otherwise the seller may be required to purchase the system outright before selling the building so the system can be removed upon transfer. It should be noted that solar and storage systems can increase the value of a building, although it can also increase complexity of the sale as the buyer may be uneducated as to its benefits.

Operation and Maintenance

Clearly delineation of who is responsible for operation and maintenance, and equipment replacement. Contract typically include monitoring, maintenance and repair, as well as inverter replacement.

Third-party ownership TPO entails owning equipment on someone else's property and therefore comes with a number of risks for both the lessor and lessee. Contracts must clearly establish the roles and responsibilities of all stakeholders as well as how disputes are to be resolved. It should be noted that the equipment is considered part of the building and will therefore require that the building owner pay for the insurance of the equipment. In most cases this can be added to the existing building insurance for a small increase in premiums.

Performance Guarantees - Equipment manufacturers typically guarantee the performance of the equipment and provide a warranty. The installer guarantees proper installation and in the case of solar, ensures the roof is structurally sound. Damages to the roof as a result of installation therefore fall on the installer.

The lessor may also guarantee a minimum level of electricity output in kWh, making a true-up payment in the case of a production shortfall. In the case of solar, whoever owns the panels will also be responsible for removing and storing them in the event that the roof is in need of repair. Risk of the lessee defaulting on payments can be mitigated by ensuring they have a sufficient credit score

Appendix F: Relevant Regulations and Policies for Distributed Energy Resources

The Industrial Conservation Incentive

Class A customers, are enrolled into the Industrial Conservation Incentive (ICI) program. They pay the GA according to their percentage contribution to the top five largest peak demand hours in a year. Class B customers with average peak demand between 500 kW and 1 MW, such as greenhouses and other smaller industrial and manufacturing industries can now also opt into the ICI program to be charged as Class A customers.

Enrolling into the ICI program has enabled the business case for behind-the-meter (BTM) storage for large Class A customers. Storage allows them to maintain their full operations while reducing their consumption from the grid and thereby reducing their contributions to the five largest peaks. They can continue operations powered by the reserves in their energy storage system. This has been the most commercially viable application of BTM energy storage in Ontario. Several companies have been successful developing software to predict when the five big peaks will occur.

Energy Storage Load-Related Charges

Because energy storage is a generator and a load it can be subject to regulatory charges for both. Load-related charges include energy charges, regulatory charges, and transmission and distribution charges (**Table 1, 2, & 3**).

Table 1. Usage Charges based on a 1 MW, 4 MWh battery.

Usage Charges (1 MW, 4 MWh, cycled daily)		
Charge name	Monthly charge	Year Total
Rate Rider for Disposition of Global Adjustment Account (2016)	\$/kWh (0.0010)	-\$1,460
Wholesale Market Service Rate	\$/kWh 0.0036	\$5,256
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh 0.0013	\$1,898
Ontario Electricity Support Program Charge (OESP)	\$/kWh 0.0011	\$1,606
Total Charge	\$/kWh 0.0050	\$7,300

Table 2. Demand Charges based on a 1 MW, 4 MWh battery

Demand Charges (1 MW, 4 MWh, cycled daily)		
Charge name	Monthly charge	Year Total
Facility Charge for connection to common ST Lines	\$/kW 1.1740	\$14,088
Rate Rider for Disposition of Deferral/Variance Accounts (General)	\$/kW 0.3151	\$3,781.20
Retail Transmission Rate – Network Service Rate	\$/kW 3.3396	\$40,075.20
Retail Transmission Rate – Line connection Service Rate	\$/kW 0.7791	\$9,349.20
Retail Transmission Rate – Transformation Connection Service Rate	\$/kW 1.7713	\$21,255.60
Total Charge	\$/kW 7.3791	\$88,549.20

Table 3. Regulatory Charges

Charge Name	Monthly Charge \$/MWh
Hourly Uplift	1.63
Daily Uplift	0.79
Monthly Uplift	0.16
IESO Admin Fee	1.22
Class B Capacity-Based DR	0.48

Emergency Backup Power

The Ontario building code already requires that emergency power for elevators, fire hose water pumps, and fans be provided for 2 hours for buildings over five stories, intending to assist residents in exiting the building in the event of an emergency. Backup power on the other hand is intended to meet non-life safety needs that are considered essential for

occupant well-being such as water, heating and elevators. The voluntary Minimum Backup Power Performance Standards created by the City of Toronto in response to the severe thunder and ice storms in 2013 sets out guidelines for this and is intended to allow residents to remain in the building during grid outages or extreme weather events¹⁷. These guidelines are primarily met through the installation of natural gas or diesel generators. However, as battery costs continue to fall, and more value stacking opportunities begin to become available batteries will become an increasingly attractive option to building owners.

¹⁷ City of Toronto. (2016). Minimum backup power guidelines for MURBs: Voluntary performance guidelines for new and existing buildings.