March 16, 2022

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON
M5H 1T1

Via email to engagement@ieso.ca

Re: Pathways to Decarbonization Study

The Power Workers' Union ("PWU") represents a large portion of the employees working in Ontario's electricity industry. Attached please find a list of PWU employers. The PWU is a strong supporter and advocate for the prudent and rational reform of Ontario's electricity sector and recognizes the importance of low-cost, low-carbon energy to the competitiveness of Ontario's economic sectors.

The PWU appreciates the opportunity to provide input on the IESO's study on the pathways to decarbonization requested by the government. The PWU believes that well informed IESO forecasts that consider the implications of decarbonizing Ontario's economy are essential to delivering energy at the lowest reasonable cost while stimulating job creation and growing the province's gross domestic product (GDP). We are respectfully submitting our detailed observations and recommendations.

We hope you will find the PWU's comments useful.

Yours very truly,

Jeff Parnell
President

PWU Feedback on Pathways to Decarbonization Assumptions Assessment

March 16, 2022

The Power Workers' Union (PWU) is pleased to submit comments and make recommendations to the Independent Electricity System Operator (IESO) regarding its Pathways to Decarbonization engagement. The PWU remains a strong supporter and advocate for the prudent and rational reform of Ontario's electricity sector and recognizes the importance of planning for low-cost, low-carbon energy solutions to enhance the competitiveness of Ontario's economy.

On October 7th, 2021, the Ministry of Energy asked IESO to assess the effects a moratorium on procuring new natural gas-fired generation would have on Ontario's electricity system, as well as to develop an achievable pathway to phase out the province's existing natural gas-fired generation. On February 24th, the IESO described its high-level approach to modelling these two scenarios, and on March 1st, posted their current assumptions for feedback.

The PWU is supportive of the IESO's evaluation given Ontario's emerging capacity gap and the limited, non-emitting options available and the risk of increased emissions and higher ratepayer costs.[1] In particular, the PWU applauds the IESO for grounding its analysis with solid verifiable data and assumptions that are supported by stakeholders.[2]

The PWU has commissioned several studies to assess Ontario's decarbonization challenges and the associated implications for total system cost, including the IESO's current analysis.[3] The PWU offers some of the lessons learned from its studies to help inform the IESO's modelling and ensure its assumptions are relevant and realistic.

The IESO has specifically asked for feedback on its list of assumptions for policy development, demand and resource forecasts and alternative assumptions as well as on its approach to transmission and operability assessments. The PWU makes the following recommendations:

1. The IESO's policy assumptions should include the application of the Federal output-based pricing system (OBPS) terms for new gas-fired generation in Ontario prior to 2030;
2. The IESO's demand assumptions should reflect an emissions budget for Ontario that would help achieve the Net Zero (NZ) 2050 objective;
3. The IESO's demand assumptions should reflect current incentives that could accelerate the adoption of lower carbon building heating and heavy-duty transportation;
4. The IESO should adopt the National Renewable Energy Laboratory's (NREL) cost assumptions, with the values adjusted to reflect Ontario's installations and include them in the IESO's modelling to accurately simulate the cost;
5. The IESO's demand forecasts and resource options should adequately characterize the transmission implications for Ontario's four planning regions - West, GTA, East and North;

[1] PWU, Submission on the IESO's 2021 APO January 2022 engagement meeting; PWU Submission on the IESO's November 2020 Resource Adequacy Engagement.
[2] Chuck Farmer, IESO Webinar, February 24, 2022.
[3] Strapolec; Emissions and the LTEP, 2016; Strapolec, DER in Ontario, 2018; Strapolec, Electrification Pathways for Ontario, 2021.

6. Available supply options should reflect Ontario energy advantages and how their development could be accelerated e.g., building new nuclear;
7. Assumptions related to viable import options should be reflected in the IESO's analysis; and,
8. The IESO's operability analysis should segregate Ontario's supply requirements by demand type: baseload, intermediate, and peak/reserve.

Recommendation #1 - The IESO's policy assumptions should include the application of the Federal output-based pricing system (OBPS) terms for new gas-fired generation in Ontario prior to 2030.

The IESO's modelling assumption to include an escalating carbon price to 2030 based on Canada's national policy is a reasonable proxy for other policy options that are intended to encourage fuel-switching and displacement of fossil fired generation.

The PWU recommends that the IESO consider the assumption that the Ontario emissions performance standard (EPS) allowance would be equivalent to the federal output-based pricing system (OBPS) for new gas-fired generation, as soon as possible, i.e., before 2030. At the very least, the IESO should identify the implications such a policy shift could have on its study outcomes. The IESO's modelling approach relies heavily on resource selection and economic signal-driven dispatch; the assumed EPS could therefore impact the timing for the available, cost-effective supply options.

Recommendation #2 - The IESO's demand assumptions should reflect an emissions budget for Ontario that would help achieve the Net Zero (NZ) 2050 objectives.

The IESO has identified a number of demand assumptions to create a reasonable high case, however, it is unclear whether these assumptions are consistent with achieving an economy-wide NZ objective.

The IESO's demand forecast should be anchored by clearly defined assumptions about the role of electrification in achieving NZ. An overall emissions reduction budget should be provided that describes the assumptions for electrification, efficiency, carbon capture, etc., that will achieve the desired NZ emissions balance. This is important as there are no evident assumptions related to: emission reductions from heavy duty transportation; the manufacturing sector, where only 20 TWh of the 90 TWh of energy consumed by this sector is identified as electrified; and, hydrogen applications, such as electric power to gas, which is already being piloted by the IESO.

The IESO could inform its modelling assumptions by considering several independent analyses: the Princeton University, Net-Zero America, Potential Pathways, Infrastructure, and Impacts Report; the 2020, Canadian Institute for Climate Choices, Canada's Net Zero Future, 2021 Report; and, the recent, Institut de L'Energie Trottier, Canadian Energy Outlook 2021 Report. Strategic Policy Economics adapted assumptions from these reports and applied them to Ontario's situation in its Electrification Pathways for Ontario, 2021 analysis. The IESO would also benefit from reviewing the assumptions included in Ontario's draft hydrogen strategy.

Recommendation #3 - The IESO's demand assumptions should reflect current incentives that could accelerate the adoption of lower-carbon building heating and heavy-duty transportation.

The IESO has identified specific assumptions regarding the penetration of electric heat pumps in the building sector based on anticipated regulatory drivers. The IESO should consider the implications of the Industrial Conservation Initiative (ICI) program on the potential to accelerate the adoption of heat pumps by the commercial sector. Since the current ICI program makes heat pumps economical for large consumers, it may be reasonable to assume this program could incent heat pump adoption as effectively as it has for storage installations.

Additionally, the ICI program, combined with the federal clean fuel standard and other federal zero emission vehicle incentives could make heavy-duty hydrogen vehicles economic today. Adoption could accelerate in the next 5 years in this area too.

Recommendation #4 - The IESO should adopt the National Renewable Energy Laboratory's (NREL) cost assumptions, with the values adjusted to reflect Ontario's installations and include them in the IESO's modelling to accurately simulate the cost impacts.

The PWU supports the adoption of the NREL's cost assumptions for the IESO's modelling. These assumptions should be adjusted to reflect Ontario's situation. The PWU supports the inclusion of several factors:

- The location cost differences in Ontario are generally higher than the average assumed by the NREL. The U.S. Energy Information Agency (EIA) provides guidance on regional cost differences;
- Applying the currency exchange rate to the cost of imports which would introduce a different premium for technology options with different Ontario domestic content; and,
- The anticipated operating capacity factors, especially for renewable forms of generation.

The IESO's assumptions include a summary of the NREL's cost expectation assumptions. The PWU suggests that the IESO should adopt the NREL's approach to Levelized Cost of Energy (LCOEs), which encapsulates their assessments of future energy sector project financing. Ontario could easily scale the fixed portion of the NREL's LCOEs as a function of capacity factors to reflect the province's circumstances. Adopting NREL's LCOE assumptions could reduce the need for the IESO to develop more assumptions and calculations for validation by stakeholders.

The development of Ontario specific LCOEs is sensitive to capacity factor assumptions. For example, with solar generation, the NREL assumes a Capacity Factor of 20-23%, which is higher than Ontario's actuals of 17-19%. The LCOE for solar in Ontario will be between 15% and 30% higher than the NREL's LCOE.

Attachment 1 provides a summary of these considerations based on a 2018 analysis and includes an additional consideration – intermittency impacts of renewable generation on curtailment, storage and need for backup energy. [4] This intermittency reduces the capacity factor of any type of paired storage and increases the need for backup capacity.

[4] Strategic Policy Economics, DER in Ontario, 2018.

The IESO acknowledges the NREL's unforced capacity at peak (UCAP) for solar at 34-41%. This is too high for Ontario, as emerging peak demand now extends to 9 p.m. in the evening in late July to early September, when no solar energy is available. The IESO should validate the amount of solar energy that can be reliably assumed to be available during the top 100 demand hours of the summer by assessing actual output compared to actual demand for the last few years. With such a validation analysis, the Ontario UCAPs for renewables should be much less than those of the NRELs, and potentially much less than the IESO has assumed to date.

Recommendation #5 - The IESO's demand forecasts and resource options should adequately characterize the transmission implications for Ontario's four planning regions - West, GTA, East and North.

The IESO has indicated that it will assess provincial needs and then regional transmission constraints.

The PWU supports the IESO's inclusion of locational factors in its 2021 Annual Planning Outlook (APO). The various regions in the province have significantly different demand drivers: agriculture and automotive in the west, mining in the north, urban growth in the GTA, and a mix in the east. Significantly different supply options are available in each region as well: CCUS equipped gas-fired generation in the west; biomass and hydroelectric in the north; nuclear at Darlington in the GTA; and, imports from Quebec in the east. Emerging technologies also have the potential to dramatically impact demand: urban areas across the province by demand-side management (DSM); hydrogen in the west and North; and, storage could optimize the use of Tx assets, particularly existing constraints in all regions that could potentially supply the GTA.

The PWU recommends that the IESO assess the available options that could best suit local needs.

Recommendation #6 - Available supply options should reflect Ontario energy advantages and how their development could be accelerated e.g., building new nuclear.

The IESO stated that its assessment will consider the availability of supply options based on the readiness of the technology and commercialization. The PWU notes two inconsistencies in the IESO's approach:

1) Large scale nuclear is defined as technologically ready but has been assigned the lowest commercial readiness score; and,
2) Gas-fired generation equipped with carbon capture is defined as more technology and commercially ready than nuclear.

The IESO's assumptions should reflect Ontario's nuclear technology advantage and recognize the undemonstrated viability of carbon capture in the province. The nuclear option is commercially ready and should not be assigned a score that precludes it from consideration. More importantly, the IESO is assuming that no new conventional nuclear could be available before 2037. Ontario has a licensed site at Darlington ready with a completed environmental assessment for new nuclear generation. This is an asset that is not assumed in NRELs project life estimates. The PWU believes the IESO's analysis will confirm the need for new nuclear that new reactors could be developed at Darlington within 10 years, before 2035. The IESO should confirm their assumptions with Ontario's nuclear operators and sector as this omission could significantly skew the outcomes and recommendations from its study.

Recommendation #7 - Assumptions related to viable import options should be reflected in the IESO's analysis.

The IESO has made assumptions in the 2021 APO regarding the availability and viability of electricity import options that could help meet Ontario's needs. In previous submissions the PWU has noted that these assumptions are questionable.[5] The IESO's pathways analysis should recognize that neighboring jurisdictions will be undertaking similar decarbonization initiatives that will impact their respective demands for electricity. The IESO's analysis should confirm that its assumptions about the viability of imports from those jurisdictions reflect the availability of supply from those jurisdictions. An analysis of Manitoba's forecasts indicates it will continue to be a net importer from Ontario.[6] Quebec, which relies on imports from Ontario in the winter, has stated that they do not intend to develop any additional hydro resources.[7]

Recommendation #8 - The IESO's operability analysis should segregate Ontario's supply requirements by demand type: baseload, intermediate, and peak/reserve.

The IESO's operability analysis will assess: the flexibility of Ontario's system to respond to hourly fluctuations; the system's ability to ramp and meet rapid fluctuations in demand caused by renewables; and, the system's capability to respond to and recover from extreme events. In previous submissions, the PWU has recommended that the IESO's modelling and procurement mechanisms should reflect the type of demand that must be met — baseload, intermediate and peak/reserve — and the types of supply best suited for meeting them.[8] The use of gas-fired generation, even without carbon capture, is likely to remain a low-cost option for flexibly meeting peak and reserve demands due to its low operating factors. Baseload supplies provide the frequency and voltage regulation that sustains quality reliability and provides black start for the grid. It is the degree to which intermediate demand can be supplied by flexible resources that is in question.

Modelling the three demand types enables the examination of the role emerging technologies could play in reducing intermediate demand volatility. These technologies include electrolytic hydrogen production, dual fuel heat pumps, storage, and demand side management of heating, water heating and electric vehicle charging. Analyses have shown that as electrification occurs, these emerging technologies could reduce peak, intermediate and reserve requirements and increase the demand for more baseload resources. Lower generation costs can be achieved by building more baseload, given

[5] PWU, Submission on IESO's 2021 APO January 2022 engagement meeting, 2022.
[6] Strategic Policy Economics, Extending Atikokan Biomass Generating Station (AGS) Operations, 2022.
[7] CBC News, "Quebec looks beyond hydroelectricity as last planned megaproject set to wrap", December 2021.
[8] Power Workers' Union Submission on the IESO's October 2021 Resource Adequacy Engagement, November 12, 2021.

their favourable operability characteristics and more efficient utilization of the distribution and transmission assets that represents 30% of the cost of Ontario's electricity system.[9]

The IESO's modelling scenarios should consider the appropriate penetration levels of emerging technologies that are required to meet demand. The IESO's DER Study approach may lead to unintended, sub-optimal outcomes given its reliance on the ICI and Net Metering Programs, which analyses show will not necessarily lower system costs. The IESO should quantify the cost difference between ICI incented DER and the optimal adoption of these technologies based on its demand projections.

Closing

The PWU has a successful track record of working with others in collaborative partnerships. We look forward to continuing to work with the IESO and other energy stakeholders to strengthen and modernize Ontario's electricity system. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for Ontario's communities; and, promote intelligent reform of Ontario's energy policy.

We believe these recommendations are consistent with, and supportive of Ontario's objectives to supply low-cost and reliable electricity for all Ontarians. The PWU looks forward to discussing these comments in greater detail with the IESO and participating in the ongoing stakeholder engagements.

End Note on References:

- Referenced PWU submissions can be found at https://www.pwu.ca/pwu-connects/submissions/
- Referenced Strategic Policy Economics (Strapolec) reports can be found at https://strapolec.ca/publications/

[9] Strategic Policy Economics, Electrification Pathways for Ontario, 2021

Attachment 1 - Modelling Total System Cost

The levelized cost of electricity (LCOE) metric is commonly used to compare the generation costs of different technology options to help determine the lowest lifecycle per MWh cost of an asset. The LCOE also helps determine the average price an electricity generator must receive for its output to break even over its lifecycle.

The LCOE is determined by the fixed and variable costs required to build and operate a generation asset. The variable cost reflects those costs that change with output (e.g. fuels costs for natural gas-fired generators) and are defined on a $/MWh basis. The fixed costs include capital and financing costs and the fixed Operating and Maintenance (O&M) costs, which are incurred regardless of the output produced. The fixed costs are spread over the asset's lifecycle and converted to $/MWh. This is based on the expected annual amount of production from the asset. This cost factor is captured by the Capacity Factor (CF) and reflects a percentage of the total theoretical energy that can be anticipated annually from the asset. This theoretical metric is similarly defined for all generation types and is the nameplate capacity (e.g. 10 MW solar facility) multiplied by the 8,760 hours in a year. This enables a cost comparison of different generation types that produce the same amount of energy in a year as shown in Table 1.[10]

Table 1: LCOE and LCOS Forecasts for New Resources Entering Service in 2026 (2020$USD/MWh)

Plant type	Capacity Factor (%)	Levelized Capital Cost	Levelized fixed O&M	Variable Cost	Total LCOE or LCOS w/o Tx Cost
Dispatchable technology					
Combined cycle	87%	$ 7.00	$ 1.61	$ 24.97	$ 33.58
Combustion turbine	10%	$ 45.65	$ 8.03	$ 45.59	$ 99.27
Battery storage	10%	$ 57.51	$ 28.48	$ 23.93	$ 109.92
Non-dispatchable Technology					
Onshore Wind	41%	$ 21.42	$ 7.43	$ -	$ 28.85
Solar	30%	$ 22.60	$ 5.92	$ -	$ 28.52

With conventional dispatchable generation e.g., natural gas-fired generation, the capacity factor represents the intended operational use of the asset for baseload supply (combined cycle plants) or peaking supply (single cycle gas-fired generation combustion turbine plants). It is inappropriate to compare the LCOE of a gas plant built for baseload to that of one serving peak demand only. Renewables, which are generally not dispatchable, the capacity factor is dependent on its geographic location and should consider potential curtailments.

Jurisdictional Premiums

Several factors must be considered when adopting LCOEs from published sources given the underlying assumptions will be different as illustrated by Figure 2:[11] The LC0E will be affected by currency exchange rates; geographic based cost premium; and weather driven capacity factors. A reference LCOE for a 1 MW solar installation in the U.S. could be $USD72/MWh but in Ontario could actually cost $120/MWh.

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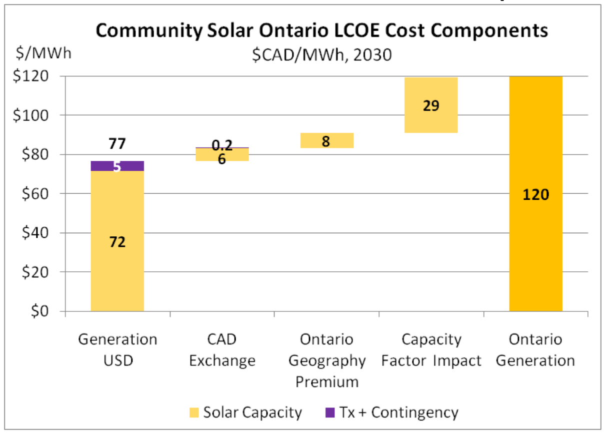
[10] EIA AEO, 2021 Table 1a

[11] Figure from Strapolec, DER in Ontario, 2018, representing a 1MW solar installation

Figure 1: Jurisdictional Contributions to VRE LCOE (Solar Illustration)



i) Exchange rate

Determining a LCOE for the purpose of comparing resource options should be based on the currency rate relevant to the jurisdiction in which it will be deployed, i.e., US versus Canadian dollars. This rate should also be applied to material inputs-domestic versus imports required to develop and operate the asset.

ii) Geographic premium

The cost of renewables in many jurisdictions are impacted by the availability of lower cost capital and operating costs e.g. lower labour, component and fuel costs and with more flexible production options. The EIA has investigated the differing costs of renewable installations across the U.S. and has published relative cost multipliers for solar and wind installations in the U.S. [12] Figure 2 reflects an assumption that Ontario cost premiums versus the published LCOEs can be expected to be similar to those in neighboring states.

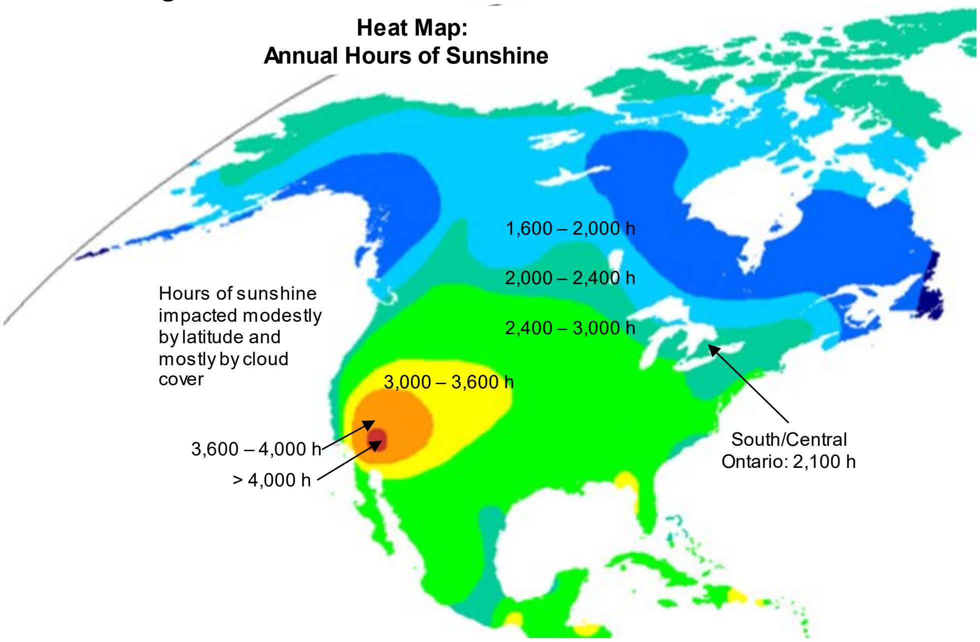
iii) Capacity Factor

The capacity factors for variable renewable energy (VRE) range significantly reflecting geographic based variations in weather and therefore adapting LCOE values from one region to another should be done prudently. For example, solar generation can produce electricity for a large part of the year in Arizona, which receives over 4,000 hours of sun per year as illustrated in Figure 3.[13] This is more than twice the annual hours of sun that Ontario receives. As a result, the average capacity factors for solar generation in Toronto would be approximately half that of Arizona solar installations. Halving a capacity factor doubles the LCOE.

[12] EIA, 2017

[13] Adapted from Strapolec, DER in Ontario, 2018

Figure 2: Annual Hours of Sunshine Across North America



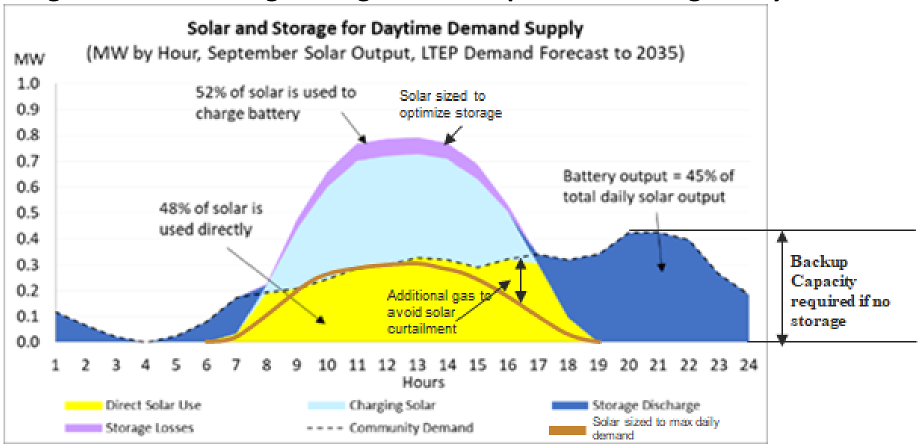
Profile Costs

The cost of backup resources for non-dispatchable generation, such as for VRE is often referred to as the "profile cost" which is based on the operational performance of a generation type compared to the demand it will supply. Comparing these costs for different types of generation is essential for comparing LCOEs. There are three primary profile cost components that are relevant to VRE, as illustrated for a solar case in Figure 5:[14]

1) The cost of backup supply to meet demand when VRE output is not available.
2) When the cost of curtailed VRE output exceeds demand and is not used.
3) The cost of storage to capture excess output to use when demand would otherwise exceed VRE output.

[14] Adapted from Strapolec, DER in Ontario. September data illustrated for solar/storage sizing purposes.

Figure 3: Contrasting Average Solar Output with Average Daily Demand



Backup Generation

The intermittent and non-dispatchable nature of VRE means that its output is not always available to supply demand when needed. Other resources are required to provide the necessary backup generation to maintain system reliability. For example, solar generation is not capable of providing electricity at night. The need for backup from gas-fired generation for a solar only facility is identical to a case without solar as the peak demand occurs at night when solar energy is unavailable. In Ontario, most of this backup is provided by natural gas-fired generation given its current low cost and rapid ramp response when required.

The real value provided by solar is its displacement of natural gas-fired generation. Therefore, the total LCOE for solar should only be compared to the variable cost of LCOE for gas-fired generation that it displaces. The LCOE parameters listed in the Table 1 would compare the solar cost of $29/MWh to the combined cycle variable cost of $25/MWh. According to the EIA data, solar is currently more expensive, however, this value is only valid if no solar energy is curtailed i.e., the maximum solar output is sized not to exceed demand as illustrated by the gold line in Figure 4.

Curtailed VRE Output

In the event that the output of a solar installation exceeds demand, this surplus energy must be curtailed unless it is stored. If it cannot be stored, then the effective capacity factor of the facility will drop in proportion to the amount that is curtailed. In the scenario illustrated in Figure 4--the solar facility is sized to meet the total daily demand when coupled with storage--the facility would need to be double the capacity required if storage is unavailable. This would increase the effective LCOE of the solar installation by a factor of two. The economics of solar are more favorable if curtailment is avoided.

Levelized Cost of Storage (LCOS)

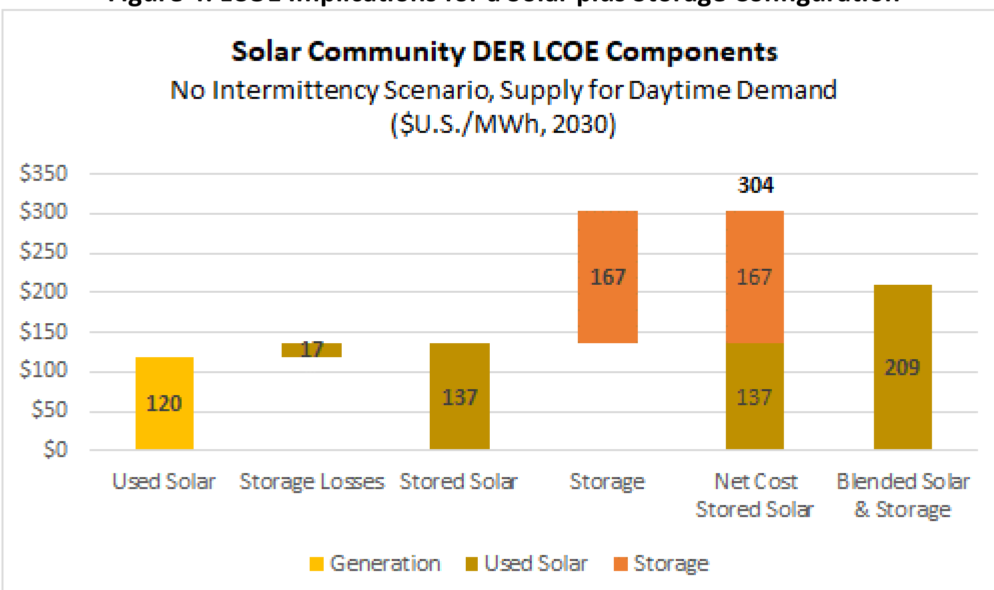
Storage is seen as a solution to both the intermittency of VRE as well as for matching output to demand. Pairing VRE with storage theoretically results in a quasi-dispatchable generator where any excess VRE generation is stored rather than curtailed and is discharged later when the VRE output is less than demand. In this scenario, the VRE would perform the same function as a gas-fired generator and hence can be compared to its total LCOE. However, the costs of the storage must be included within the LCOE.

Storage costs have their own Levelized Cost of Storage (LCOS) that must also be adjusted to reflect any jurisdictional premiums.

Figure 5 illustrates the operational profile of a theoretical solar facility coupled with a battery. Solar can pair well with storage due to the diurnal cycle of demand dropping at night when there is no solar output, even though demand rises in the evening. The capacity of the solar facility must be sufficient to meet the energy demand for the entire 24-hour period and account for losses that will be incurred by the storage device or battery (e.g. lithium-ion batteries have approximately 85% round-trip efficiency). Demand during daylight times is supplied directly with solar output with any excess being used to charge the battery. As the sun sets, the battery would begin discharging to meet evening and overnight demand.

The blended LCOE for a hybrid solar plus storage system would consider the MWh of solar output directly used and the MWh required to charge the battery and losses as illustrated in Figure 5.[15] With a solar LCOE of $77/MWh combined with storage results in a blended LCOE of a $134/MWh.

Figure 4: LCOE Implications for a Solar plus Storage Configuration



Grid Transmission Costs

Connecting generation assets to the grid requires the construction and/or use of transmission and/or distribution system infrastructure (e.g. wires, poles, and substations). These costs are affected by two factors: the location of the asset with respect to existing transmission and distribution infrastructure (not technology dependent); and, the transmission/distribution capacity that is utilized.

The intermittency and associated low capacity factor of VRE reduces the utilization of the transmission system. The transmission system must be sized for the maximum output of the VRE, which could be

[15] Adapted from Strapolec, DER in Ontario, 2018

five times the average output of the VRE due to intermittency (e.g. grid scale solar capacity factors in Ontario are less than 20%).[16] Similarly, distribution system costs may also be impacted.

These transmission cost implications are included in the LCOES for various technologies established by the EIA and shown by Table 2. The cost implications correlate well with the capacity factors illustrated by Figure 7. It shows that the Tx cost for a combined cycle natural gas-fired plant is $0.93/MWh with a CF of 87% compared to the Tx cost for solar which is $2.78/MWh with a CF of 30%.

Table 2: LCOE Implications of Transmission Costs

Plant type	Capacity Factor (%)	Total LCOE or LCOS w/o Tx Cost	Levelized Tx Cost	Total LCOE or LCOS w/ Tx Cost
Dispatchable technology				
Combined cycle	87%	$ 33.58	$ 0.93	$ 34.51
Combustion turbine	10%	$ 99.27	$ 8.57	$ 107.84
Battery storage	10%	$ 109.92	$ 11.92	$ 121.84
Non-dispatchable Technology				
Onshore Wind	41%	$ 28.85	$ 2.61	$ 31.46
Solar	30%	$ 28.52	$ 2.78	$ 31.30

Modelling the Total System Cost

Many electricity system models use average LCOEs to estimate the cost implications. Unfortunately, these averages do not capture the effects of intermittency of VRE) and its ability to respond to demand variations.

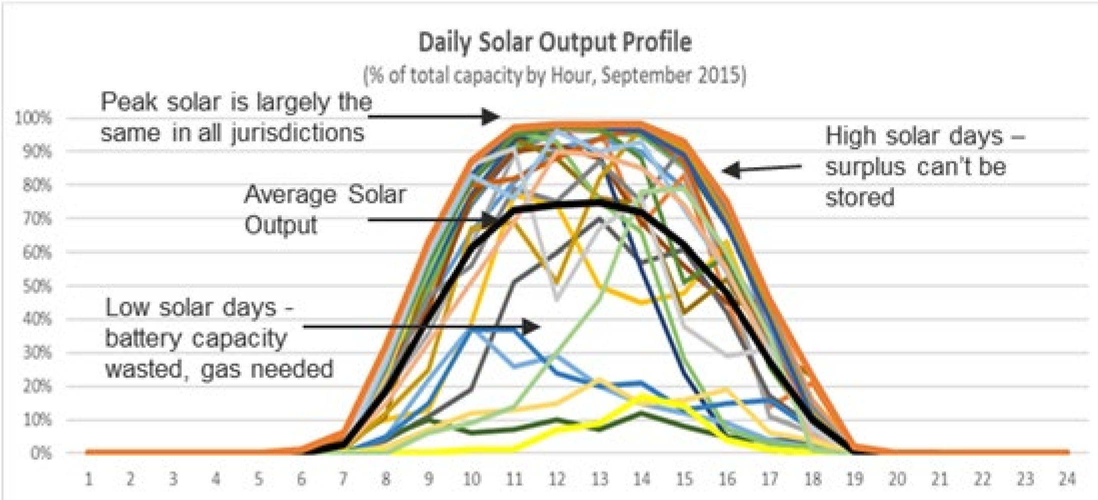
Strategic Policy Economics' analysis explores these considerations that impact the fidelity of any required system modelling. [17]

Impacts of Mitigating VRE Intermittency

Since electricity must be consumed or stored immediately when it is generated, hourly supply variations that are asynchronous with demand can have significant negative impacts. For example, the actual solar output on any given day could exceed the average solar output. It could also be much less, even zero, due to cloud cover. These variations over a month are illustrated in Figure 8.

[16] IESO Power Data; Strapolec Analysis
[17] Strapolec, DER in Ontario, 2018.

Figure 5: Sample Daily Solar Output Variations

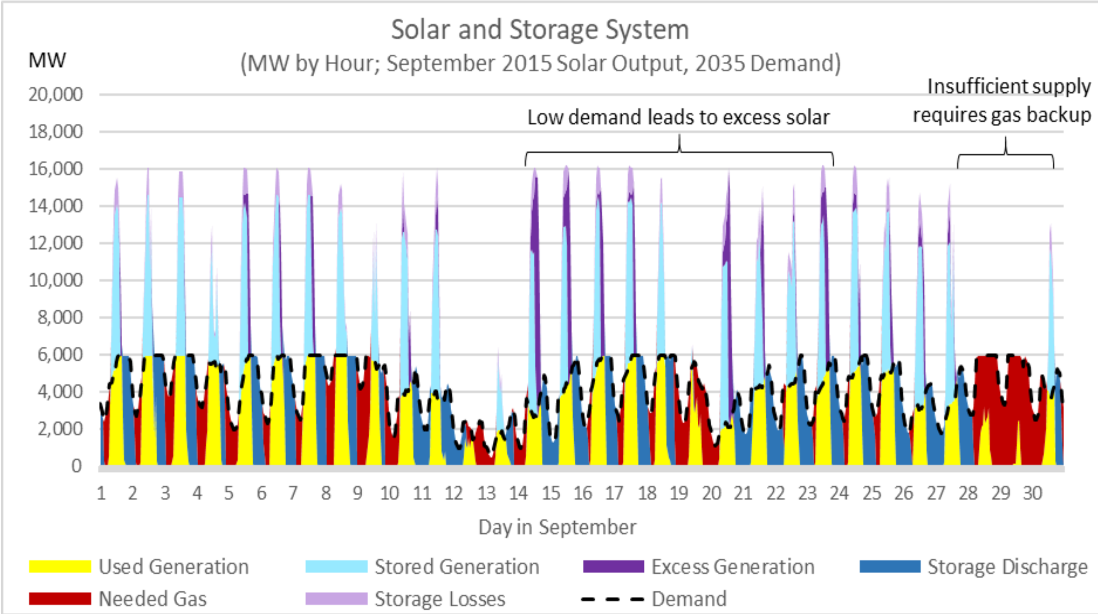


Even when paired with storage, this intermittency, on some days, can lead to insufficient solar generation to fully charge a battery, thereby wasting the capacity of the battery and requiring backup generation. On other days, there may be more than optimal sunshine causing output to exceed demand and/or storage capacity which leads to curtailment. Both of these circumstances reduce the capacity factor and increase the LCOE of these paired assets.

Impacts of Demand Variability from VRE Integration

Integrating VRE not only requires mitigating the intermittency of VRE output but also variations in hourly, daily and seasonal demand. This creates challenges for hybrid VRE and storage system to cost effectively meet demand while maximizing use of storage assets. Figure 9 shows the operating profile of a solar and storage system compared to the demand in Ontario for a month. While some days a combination of solar and storage may meet most of the demand for a 24-hour period, despite some excess generation that cannot be stored, there are other days where VRE output is insufficient. Compensating for this mismatch between output and demand requires backup generation e.g., natural gas-fired generation to maintain system reliability sometimes for days even during periods of low demand.

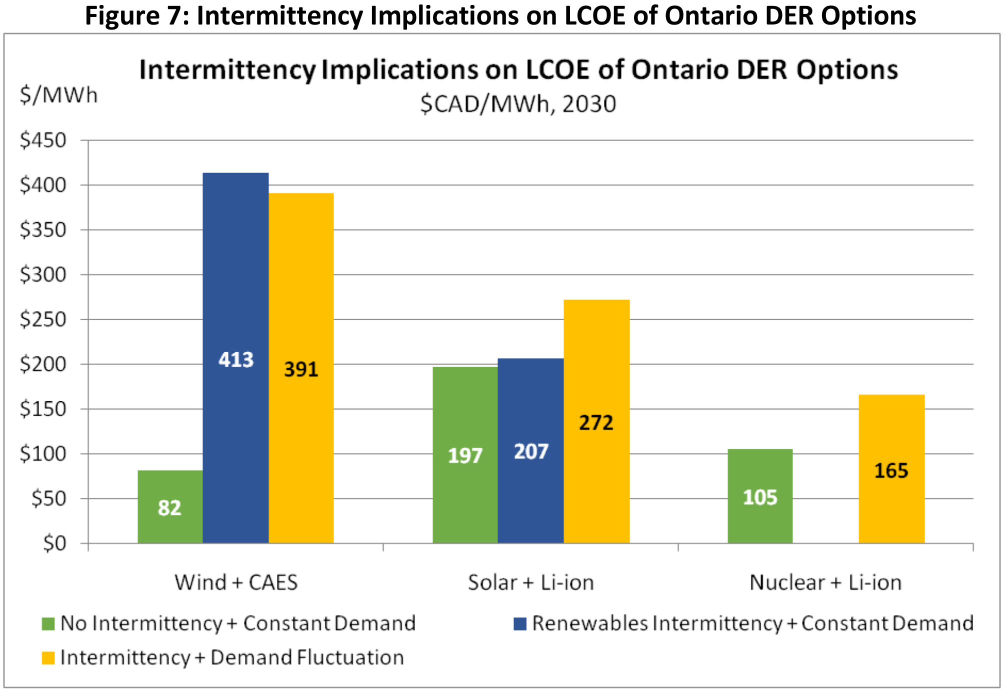
Figure 6: Sample Daily Solar Output and Demand Variations



Cost Implications

When VRE output, whether direct or stored is not utilized as forecast, LCOE costs increase. Figure 10 shows that intermittency and demand variability undermine anticipated LCOE based on average capacity factor data. Solar costs are only marginally impacted by intermittency while the costs of wind generation intermittency can be significant. However, demand variability substantially increases the effective LCOE of hybrid solar storage installations.

Figure 7: Intermittency Implications on LCOE of Ontario DER Options



These factors that contribute to this cost increase are illustrated for the solar case in Figure 11. Solar LCOE costs increase by 30% due to the curtailment of unneeded solar output. Unused storage capacity increase costs by another 25% with a small cost increase required to provide backup generation capacity.

Figure 8: Community Solar-Based DER Component LCOE Contributions