PWU Submission to the IESO on the DER Potential Study

October 28, 2022

On September 30, 2022, the IESO released the final Distributed Energy Resources (DER) Potential Study report and supporting appendices prepared by its consultants and invited stakeholders to submit feedback on the relevant results, other messages of high importance, appropriateness of the recommendations, and additional actions including other areas of analysis.

Context

The DER Potential Study report [the Report] identifies the economic potential for DER penetration and quantifies the associated achievable system benefits under three scenarios:

1) *Business as Usual (BAU)* - A projection reflecting existing market conditions, technological trends and the IESO's 2021 Annual Planning Outlook (APO) Reference Case for demand;
2) *Expanded Business as Usual (BAU+)* - An expanded electrification and decarbonization trajectory in-line with the IESO 2021 APO high demand case and general policy, market and technology advances; and,
3) *Accelerated* - Accelerated efforts to achieve net-zero with a greater reliance on DERs to meet system needs, including with increased efforts to integrate DERs.

The DERs included Behind-the-Meter (BTM) and Front-of-the-Meter (FTM) solar and storage and high potential Demand Response (DR) measures with Residential Thermostats, Commercial/Industrial Load Flexibility and Large Commercial Heating Ventilation and Air Conditioning (HVAC) controls. In the longer-term, additional DER potential emerges for Passenger Electric Vehicles (EVs) including smart charging and V2B/G applications.

Costs and possible grid benefits, including contributions to Seasonal Capacity, Energy, Transmission and Distribution (T&D) investment deferrals and Ancillary Services were provided. Economic potential results were generated based on the grid benefits of DERs relative to their costs, with the most cost-effective DER measures prioritized first. Achievable potential results were determined by incorporating customer/participant-side economics (e.g. acceptable payback thresholds) and market barriers, including the degree to which customers/participants could be remunerated for the grid benefits provided by their DERs.

Summary of PWU Recommendations

The PWU has reviewed the Report and cautions the IESO regarding the results and recommendations that will be used to inform decision-makers. The Report's findings are predicated on assumptions that are now superseded or originally inappropriate and have been developed using analytical methods not suitable for the recommendations and findings that the Report is communicating. As a result, the recommendations are questionable in some areas with significantly overstated net benefits, and more relevant recommendations are absent from the Report.

The PWU recommends that:

1) The IESO should have the outcomes adjusted to reflect the IESO's planned 5500 MW procurements before the recommendations are provided to decision-makers;
2) The Report's findings should clearly differentiate the measures that provide primarily capacity benefits versus those that provide primarily energy benefits for communications with decision makers;
3) The IESO should advise decision makers to focus on the BAU+ outcomes (post the above noted adjustments) because the demand and carbon pricing assumptions that form the key drivers of DER potential are grossly overstated for the accelerated scenario and grossly understated for the BAU scenario;
4) The recommendations regarding solar should be removed from summaries of the Report's findings, as their benefits are overstated given inadequate modelling, gross assumptions about carbon pricing policies and the unaddressed risk of stranded costs under future supply mix scenarios;
5) The qualitative narrative expounding on the relevance of DERs and extolling the potential of DERs should be qualified in subsequent communications with decision makers as the findings do not support the Report's claims;
6 Since the BTM HVAC, EV and other DSM options are the most cost-effective, the OEB's role in establishing TOU rates should be explored before the IESO financially commits to its administered market solutions; and,
7 The two most cost-effective mechanisms for minimizing capacity risks in Ontario are not considered in the Report but should be explored: Hydrogen electrolysis and hybrid dual-fuel heat pumps.

Recommendation Details

Recommendation #1 - The IESO should have the outcomes adjusted to reflect the IESO's planned 5500 MW procurements before the recommendations are provided to decision-makers.

A key assumption in the Report is that all existing resources contracts in Ontario's supply mix would be renewed and that no new natural gas-fired generation would be built. The Report assumes that the IESO will procure a combined solar+storage capacity of 1000 MW in 2030 to meet the capacity gap defined in its Annual Planning Outlook (APO). The Report's analysis subsequently assumed that the remaining capacity needs were the system needs against which the DER potential would be assessed.

In April 2022, the IESO revised its long-term procurement objectives to include 4000 MW by 2027 in multi-year contracts for 2500 MW of storage and 1500 MW of new natural gas-fired generation and an additional 1500 MW (undetermined resources) by 2030.[1] This additional 5500 MW of committed capacity undermines the assumptions used in the Report which relies on the ability of DER to reduce capacity costs. Subtracting the originally assumed 1000 MW from the IESO's new 5500 procurement target reduces the system capacity requirements of 4500 MW by 2032 as shown in Table 1.

[1] IESO, E-LT1 RFP webinar materials, October 18, 2022; and IESO, LT1 RFP and Additional Mechanisms Engagement June 2022.

Table 1 - Impact on 2032 Needed Capacity of New IESO Procurements			
Capacity need (MW)[2]	**BAU**	**BAU+**	**Accelerated**
Summer Need in Report	2,600	5,600	6,900
Achievable potential	1,300	2,200	4,300
New Summer Need	*-1,900*	*1,100*	*2,400*
Winter Need in Report	900	6,400	13,300
Achievable potential	1,000	1,800	3,600
New Winter Need	*-3,600*	*1,900*	*8,800*

This suggests that there is no capacity need in the BAU scenario, marginal capacity need in BAU+ scenario and some remaining material capacity need in the accelerated scenario that emerges as the decade comes to a close.[3] However, the achievable potential, as modeled in the Report, exceeds the projected capacity requirement for summer in all scenarios. The Report states that DER capacity additions that exceed the system needs "*would provide little or no further benefit*" and "*would no longer receive capacity benefits in the analysis*".[4] This disparity with the Report's conclusions suggests that the results and net benefits claimed in it should be re-examined.

Recommendation #2 - The Report's findings should clearly differentiate the measures that provide primarily capacity benefits versus those that provide primarily energy benefits for communications with decision makers.

The Report identifies two significant factors related to the lifetime net benefits of DER:[5]

1) Potential Peak Capacity Benefits:
   a. BAU+: Capacity benefits of $6.6 B for generation and transmission versus $6.0 B in lifetime costs
   b. Accelerated: Capacity benefits of $13.3 B in generation and transmission versus $11.3 B in lifetime costs
2) Potential Energy Benefits:
   a. BAU+: $1.6 B in energy benefits increase the total DER lifetime net benefits to $2.3 B
   b. Accelerated: $40.2 B in energy benefits increase the total DER lifetime net benefits to $42.3 B

This summary assumes that all modelled costs are incurred in achieving the capacity benefits.[6] The incremental energy benefits then contribute most to the net benefits, especially for the Accelerated

[2] The system needs identified in Table 7-1 on page 75 of the report are illustrated. This differs from the values in Table 2-6 on page 14 of the report. The source for the discrepancy was not resolved in the time available.
[3] DER Potential Study report, Figure 2-2, page 7
[4] DER Potential Study report, page 33
[5] DER Potential Study report, Table 6-2, page 64
[6] The methodology of the study for establishing the Achievable Potential first selects DERs according to their capacity contributions. After the stack of achievable DERs potential is established, it appears that no additional resources are identified purely for addressing energy needs. As a result, it is assumed that all costs are incurred in achieving the capacity benefits (which also entail the T&D deferral benefits). As a result, energy benefits are

scenario as noted in the Report. The main body of the Report clarifies these stated benefits as likely being excessive. The key drivers of these benefits are distinctly different:

1) Demand growth impacts on the system capacity needs and the related avoidable capacity costs become the base for determining the potential benefits from reducing the peak capacity needs.
   a. This sets the value proposition for DR and other BTM resources and the economic drivers for adoption and it is relatively consistent across all scenarios.
2) Energy benefits are driven by the assumed energy and carbon price forecasts which impacts market value and the retail rates that drive adoption.
   a. Energy is the primary source of value for solar and Front of the Meter (FTM) storage in the accelerated scenario.
   b. However, the energy price drivers differ significantly between scenarios. The Report states that for the accelerated scenario, "*the assessment of avoided costs, which assume highly constrained electricity supply under the Accelerated scenario (which assumes only renewable generation and storage are added to meet future electricity needs), causing energy avoided costs to rise nearly seven-fold over the BAU+ scenario by 2040. In reality, comprehensive and strategic integrated resource planning, in which centralized resources and energy efficiency would be combined with DERs and energy trade, would likely have a feedback effect that somewhat curtails these extremely high avoided costs*."[7]
   c. It must be noted that the procurement of an additional 4500 MW of supply over that assumed in the Report, will alleviate to some degree the supply constraints affecting energy price as outlined previously in the PWU's Recommendation #1.

The Report further clarifies that solar only helps achieve modest peak capacity savings:[8]

1) Under the BAU+ scenario, 34 MW of the identified 2200 MW is from solar which is negligible;
2) Under the Accelerated scenario: 400 MW of the achievable 4300 MW which is less than 10%.

As a result, it would serve decision makers better if DERs with high energy benefit values were discussed separately from those with primarily capacity values. The DERs most sensitive to the energy benefit modelling assumptions are storage, solar DG, EV fleet charging and V2B/G EV services.[9] The Report's Executive Summary appears to gloss over this short-coming in the modelling, suggesting that "*solar and storage make up an increasingly large portion*" of the economic potential and that the "*accelerated scenario likely represents the most probable depictions of future DER potentials*." This is misleading given the actual findings of the Report.

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deemed incremental benefits to the capacity benefits with no incremental costs and hence can be identified as the contribution to net benefits that they provide as expressed here.

[7] DER Potential Study report, call out box on page 53

[8] DER Potential Study report, Figure 6-8, page 67; Table 6-7, page 74

[9] DER Potential Study report, Figures 5-15 and 5-16 illustrate those DER options where the potential economic cost effectiveness increases significantly with the Accelerated scenario. An assessment of the detailed spreadsheets indicates a lack of clarity with respect to how storage and V2B/G create system energy savings costs as it takes more energy to use outputs from storage or V2B/G than electricity directly from the system, as noted on page 52. As the Report assumes that gas-fired generation is on the margin virtually all hours of the year, there is no opportunity to arbitrage the cost impacts of carbon pricing nor are there any stated or obvious assumptions that would cause great cost disparities between off peak HOEP and on peak HOEP.

This important caveat on the report's implications warrants mention in any IESO-prepared executive summary of these findings and those DER options that are subject to it should be identified.

Recommendation #3 - The IESO should advise decision makers to focus on the BAU+ outcomes (post the above noted adjustments) because the demand and carbon pricing assumptions that form the key drivers of DER potential are grossly overstated for the accelerated scenario and grossly understated for the BAU scenario.

The Report states that the primary drivers for the cost-effective potential of DER are demand growth and pricing.

a) Implications of Demand Growth Assumptions

The Report appropriately downplays the BAU scenario outcomes given the modest assumptions for load growth.[10] Several previous PWU submissions to the IESO have recommended that planning recognizes at least the IESO APO 2021 high demand case, which has been captured in the Report's BAU+ scenario and potentially higher for EV adoption and building heating in winter, as the report purports to do for the Accelerated scenario.[11]

While the Accelerated scenario shows a peak demand of 38 GW, similar to the PWU's projections,[12] the PWU analysis for 2032 includes the full electrification potential of the Ontario economy necessary to meet the 2030 emissions targets.[13] By comparison, the Report reflects a subset of electrification assumptions and arrives at the same total by including unrealistically aggressive assumptions in the areas that support DER adoption, potentially overstating their potential. The following two examples illustrate the risks:[14]

- The Accelerated scenario EV adoption assumption of 100% of sales by 2032 is aggressive. The most aggressive jurisdictions in Canada (e.g. BC, Quebec, and the Government of Canada) have set adoption targets of 100% of new sales by 2035, a few years later. A more reasonable assumption would be that included in the BAU+ scenario assumption of 76% of sales by 2032.
- The Accelerated scenario building heating assumption sets a target for converting 40% of Ontario buildings to heat pumps by 2032. Achieving this in less than 10 years will be challenging. The Report cites an EPRI study of Canada's electrification potential as a source for this assumption. However, EPRI assumes that nationwide electric heating penetration may reach 40% of the buildings by 2032. However, this statistic is heavily influenced by the existing building heating penetration in hydro-electric intensive jurisdictions like Quebec and BC. The EPRI growth curves suggest about 20% penetration for Ontario, or about half the value assumed in the Report for the Accelerated scenario. Most relevant is that the assumption in the Report for the BAU+ scenario is 20%.

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[10] DER Potential Study report, page ES-3
[11] PWU submission on the IESO's 2021 APO, February 17, 2022.
[12] DER Potential Study report, Page 8
[13] PWU-sponsored study by Strategic Policy Economics, "Electrification Pathways for Ontario", 2021.
[14] DER Potential Study report, Volume 2, pages 43 and 44

The anticipated outcomes previously described in Recommendation #1 and the risks associated with the demand driven assumptions that shape the Accelerated scenario suggest decision makers should be advised to disregard outcomes of the Accelerated scenario as documented.

b) Implications of Pricing Assumptions

Price and the inherent benefits are the primary drivers for the adoption of new technologies. Two critical and potentially related factors are the assumed pricing forecasts for retail and carbon. An argument can be made that the pricing assumptions in the Report for the BAU+ scenario are reasonable. For the Accelerated scenario, the reasonableness of these assumptions is not so clear:

- The retail price growth that is stated to drive achievable DER adoption is assumed to be 7% per year in the Accelerated scenario versus 1.5% in the BAU+ scenario.[15]
  - The report also states that the avoided cost of energy, notionally the HOEP, will increase by 30% per year over the study period (i.e. to 2032).
  - Since the carbon price assumptions for the BAU+ and the Accelerated scenarios are similar until 2030, the driver for the higher price assumptions in the Accelerated scenario remains unclear, particularly in the near term. The IESO should provide clarification. Note that the assumed HOEP by year was not found in the Report.
  - Actions that would result in these significant cost increases would likely be unacceptable to government and rate payers.
  - Conversely, the PWU has provided a supply mix scenario to the IESO that would reduce costs over time while achieving net zero.[16]
- The carbon price assumptions between the BAU+ scenario and the Accelerated scenario only diverge after 2030.
  - The BAU+ assumes that the carbon price remains at the currently stipulated federal level of $170/tonne.
  - The Accelerated scenario assumes the carbon price will increase by an additional $15/year to $350/tonne by 2042.
  - No rational has been provided for this assumption. It is noteworthy that Canada's Clean Electricity Regulation will prohibit the operation of any gas-fired generation post 2035.
  - PWU analyses recommended options to the IESO that would effectively keep the carbon price at about $100/tonne.[17]
  - The "backloaded" carbon price assumed in the Accelerated scenario strongly influences the suggested $42B in lifetime energy benefits. The enhanced benefits of the Accelerated scenario as compared to the BAU+ scenario benefits will not be material in the next 10 years.

The Report should be revised to make this clear and advise decision makers to focus on and prioritize the benefits from generation capacity and deferred Tx investments.

[15] DR Potential Report, Vol 2, page 35
[16] PWU-sponsored study by Strategic Policy Economics, "Electrification Pathways for Ontario", 2021.
[17] PWU-sponsored study by Strategic Policy Economics, "Electrification Pathways for Ontario", 2021.

Recommendation #4 - The recommendations regarding solar should be removed from summaries of the Report's findings, as their benefits are overstated given inadequate modelling, gross assumptions about carbon pricing policies and the unaddressed risk of stranded costs under future supply mix scenarios.

The DER Potential Study report states: "*In the case of solar, increased potential is driven by a significant increase in energy needs and carbon price exposure and is a phenomenon that occurs despite solar's diminishing peak capacity value*". The report then claims to reinforce *"the significant value solar generation can provide in helping to avoid high-priced electricity that would otherwise be satisfied by gas generation*".[18]

The value of solar has been mis-represented in this analysis:

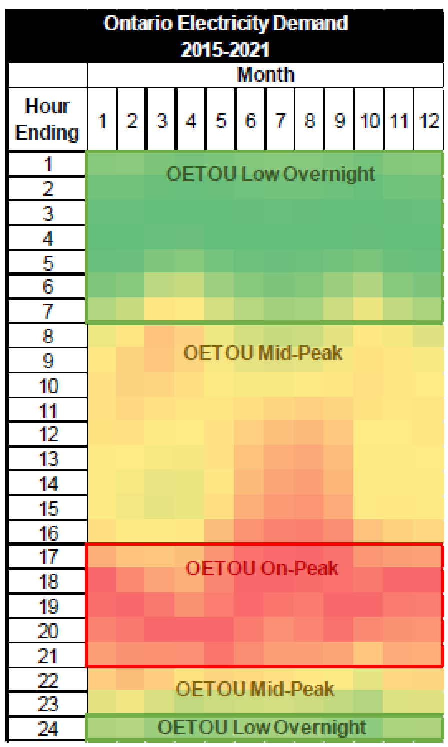
a) Capacity Contribution assumptions

Three solar capacity assumptions contribute to overstating its value and role:

i. The Report assumes peak demand times are between 4pm and 8pm.[19]

The OEB indicates that these peak demand times are changing to be between 4pm and 9pm as shown in Figure 3. [20] Resources for meeting peaks must be available for the entire duration of the peak period. Shifting and extending the peaks to later in the day reduces the ability for solar to supply peak demand.

Figure 3: Ontario Electricity Demand – Heat Map.

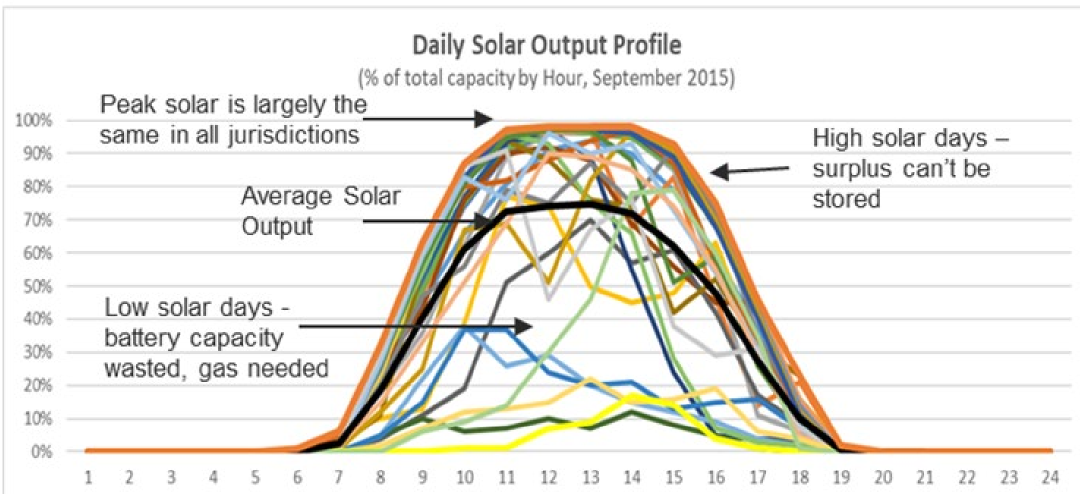


[18] DER Potential Study report, page ES-3
[19] DER Potential Study report, pages 23, 24
[20] OEB TOU Pilot

ii. The Report assumes solar contribution to peak supply capacity of 28% of its nameplate in summer.

Peak demand days can occur in late August and early September. Solar output in Ontario is not 28% on average at 8pm, let alone 9pm, even in August. Actual solar output from Ontario in September shows that the sun sets shortly after 7pm as indicated in Figure 4. Average solar output is below 28% after 5pm. Capacity contributions are part of ensuring that the system Loss of Load Expectation (LOLE) is compliant with the requirements of Northeast Electricity Reliability Corporation (NERC) which ensures that such events can occur no more frequently that 2.4 hours a year. An assessment of the solar output during the top 100 demand hours in each of the last three years shows that solar can have 0% output. An assumed 28% contribution from solar to system peak reductions is therefore not reasonable.

Figure 4 – Solar Output Profiles for September in Ontario (2015)



Source: September 2015 IESO actuals, not curtailed, Strapolec analysis

Environment and Climate Change Canada has also grappled with this question and has advised stakeholders that it is considering assuming that solar contribution to mitigating system peaks should be 0%.[21]

iii. The Report uses a capacity cost reference based on a solar+storage system that will only be marginally higher than a single combustion gas turbine (SCGT).[22]

Analyses have proven that a solar+storage solution cannot replace the peak capacity capabilities of a gas-fired generation plant without significantly greater hours of storage.[23] With proper modelling of solar intermittency, such as illustrated in Figure 4, simulations show that a gas-fired generator is required to supplement a solar+storage solution. The cost of a solar+storage solution will therefore be much higher than has been assumed. This underestimation of the capacity costs of solar+storage biases the Report's analyses of other more cost-effective

[21] ECCC, CER Modelling Webinar, September 14, 2022.
[22] DER Potential Study report Vol 1 page 34; and Vol 2, Table E-8, page 51, as referenced on page 20.
[23] Strategic Policy Economics, "DER in Ontario", 2018

solutions. It is likely, particularly after the IESO's new supply mix is considered, that the Report overstates the potential for new solar.

b) Inadequate modelling of solar output and its relationship to demand

The basic building block of the Report's supply and demand models includes the use of 9 typical hourly profiles that represent average demand and supply capabilities for three periods (winter, summer, shoulder) and for peak and off-peak weekend and weekdays.[24] Solar output profiles for the summer are based on the average hourly solar output in a day from June 1 to September 14, similar to demand.

This approach smooths out the impacts of intermittency on the daily operations, such as the effective use of storage and the ability to contribute to system peaks. Analyses and multiple academic papers have shown that this modelling approach produces erroneous results that overestimate the capability of renewables to provide electricity and underestimate the costs of the required compensating storage. Appendix A includes the PWU's previous advice to the Ministry of Energy on this matter.[25] Furthermore, the IESO uses full 8760-hour models in its NWA assessment methodology for regional planning.[26]

c) Inappropriate stacking of solar in the assessment of system impacts

The modelling approach in the Report for calculating the achievable potential for addressing system needs assumes that the identified solar generation is selected first and then the scenarios are completed by sequentially selecting the most cost effective DERs.[27] The Report explains that this approach allows for the development of new load shapes against which the appropriate contributions from other DERs can be calculated.

There are three problems with this approach:

i. The solar profiles used are averaged and not indicative of the actual load impacts;
ii. Adding properly modelled solar profiles that reflect intermittency would make it harder for other DERs to provide capacity contributions; and,
iii. Solar is the least cost-effective DER identified for all three scenarios[28]

The method suggests that the performance of these other types of DER is not as related to cost effectively address system needs, but rather to compensate for the mismatch of solar output to demand. If a consistent methodology was used to stack DER contributions for system impacts (as was used for assessing the economic potential,[29]) solar would be added last. Under the anticipated revised supply mix identified in Recommendation #1 above, no solar inclusions may be cost-effective.

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[24] DER Potential Study report Vol 2, page 15
[25] PWU Submission to the Ministry of Energy's Request for Information (RFI) on Scoping a Cost-Effective Energy Pathways Study for Ontario, June 13, 2022.
[26] IESO, Regional Planning Process Review Non Wires Update, Analysis Methodology, August, 2022
[27] DER Potential Study report, Vol 2 page 41
[28] DER Potential Study report, Figures 5-14 to 5-16 on pages 51 and 52 all show distributed generation to be the least cost effective.
[29] DER Potential Study report, Vol 2 page 25

The question of whether solar should be in the supply mix is not a DER question but is rather a supply mix question, which is discussed below.

d) Unrealistic carbon pricing overstates the value claims

The economic potential for both BTM and FTM solar is impacted by the pricing assumptions mentioned in Recommendation #2 above.

BTM solar potential is driven by the projected annual increase in the retail price and the presence of the Net Metering program.[30] The report identifies that "*net metering is a non-economic application of DERs*"[31] Coupling with the high Accelerated scenario pricing assumptions Net Metering will be an even greater uneconomic driver of solar adoption.

FTM solar responds to the marginal hourly price, which under the BAU+ and Accelerated scenarios is set by gas-fired generation for virtually all hours of the year.[32] The high carbon price values assumed add $130/MWh to the cost of natural gas fired electricity by 2042, the time frame over which the lifetime value of the solar benefits are assessed. In the absence of well-considered cost-effective supply mix alternatives that would mitigate the use of and cost of natural gas fired generation, the Report presents unreasonably high value contributions from solar.

e) Unrealistic future assumptions for a constrained supply mix

For the BAU scenario, the report has assumed "*reasonable procurement of transmission connected resources by the IESO to meet resource adequacy needs and other planning criteria*." However, for the BAU+ and Accelerated scenarios, "*the resource supply mix only assumes committed and planned resources*" in order to establish conditions of a "*constrained transmission-connected resource development*".

The Report's constrained system approach has directly led to higher energy costs that have subsequently biased the energy values that dominate the net benefits, as discussed earlier. The Report describes the value implications as follows: "*It should be noted that this value is derived from the assessment of avoided costs, which assume highly constrained electricity supply under the Accelerated scenario (which assumes only renewable generation and storage are added to meet future electricity needs), causing energy avoided costs to rise nearly seven-fold over the BAU+ scenario by 2040. In reality, comprehensive and strategic integrated resource planning, in which centralized resources and energy efficiency would be combined with DERs and energy trade, would likely have a feedback effect that somewhat curtails these extremely high avoided costs. Thus, the lifetime benefits presented in this study should be interpreted as an extreme case that can be mitigated by said comprehensive integrated resource planning.*"

The Report also notes elsewhere that "coherent, real-world planning and integration could help to mitigate these extremely high avoided costs."[33]

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[30] DER Potential Study report Vol 1, pages 34; Vol 2, pages 39, 46
[31] DER Potential Study report, page 3
[32] DER Potential Study report Vol 2, page 52
[33] DER Potential Study report, footnote 44 on page 63

The Report's assumptions suggest that the identified benefits from solar should not actually be equated to the value of solar, just the value of reducing the cost of gas-fired generation through "*coherent, real world planning and integration*". This may also be achievable from other supply mix options. As mentioned earlier, analyses have shown that alternative non-emitting supply mix options exist that mitigate these costs more effectively than those modelled in the Report.

f) Unaddressed stranded costs for any new installed solar when more cost effective, non-emitting, supply mix choices emerge

Ontario will need a new approach to providing affordable non-emitting electricity given public concerns about climate change and policy pressures, e.g., pending Canadian Electricity Regulation to criminalize the operation of natural gas-fired generation after 2035. Analyses have also clearly established that while intermittent supplies work cost effectively with natural gas-fired generation, intermittent supplies are not as cost effectively integrated with other non-emitting baseload options such as hydro and nuclear supported by storage, which should be the preferred choice given the public's concern about climate change.

It remains unclear, as Ontario's new supply mix emerges to 2035, whether solar installations will remain cost effective in the absence of natural gas generation. There is a material risk that these assets will become a stranded cost for the system. This risk is not addressed by the Report.

Given these demonstrated uncertainties regarding the assumptions and modelling approaches for solar, in the absence of the additional recommended analysis the findings of this report should not be used by decision makers to set the direction for Ontario's solar policy.

Recommendation #5 - The qualitative narrative expounding on the relevance of DERs and extolling the potential of DERs should be qualified in subsequent communications with decision makers as the findings do not support the Report's claims.

The Executive Summary and Introduction in the IESO's Report make use of qualitatively based words and phrases-- such as "ample", "significant", "material", "hallmark", "exciting", "increasingly turning to DERs" to describe the benefits of DERs.

Two factors suggest that these descriptions should be reconsidered before informing decision makers of the Report's findings:

a) DER Adoption has been driven by generous provincial rate incentives.[34]

[34] The proceedings of the OEB Framework for Innovation Working Group (FEIWG) established that the main driver of DER adoption in Ontario is the generosity of the ICI and Net Metering programs as summarized by the PWU submission to the OEB on the FEIWG final reports

Ontario's Industrial Conservation Initiative (ICI) continues to attract investments in high-cost solutions to help Class A consumers avoid energy costs. An OEB analysis of this program showed that the ICI was paying over four times the value realized in capacity reduction.[35]

Net Metering rewards those who install solar panels with rate benefits that exceed the costs of any electricity that is avoided.

These programs are not cost effectively reducing electricity system costs. In fact, the ICI program is responsible for 50% of the cost growth experienced by non-RPP Class consumers since 2011.

Absent the incentives of these programs, DER demand would erode given their associated higher costs. It is inappropriate to say that "*DERs are a major driver of the rapidly evolving electricity landscape*". It is more appropriate to say that favorable government polices are encouraging the adoption of high-cost technologies that are not yet ready for broader market penetration.

b) The value of DERs presented in the Report is modest.

The lifetime net benefits identified in the Report are in the order of $2B when the energy benefits are discounted. These will be smaller after reflecting the IESO's new procurements and implications of the residual supply mix. Averaged over 20 years this represents about $100M/year. This is less than 0.5% of the value of Ontario's annual $20B+ electricity sector.

In this context, the affordability implications for Ontario's electricity system are modest at best. The findings are hardly "significant", "material" or a "hallmark" of change.

These considerations should be made clearly evident when the IESO presents the Report's outcomes to decision makers for performing reasoned evidence-based assessments.

Recommendation #6 - Since the BTM HVAC, EV and other DSM options are the most cost-effective DER options, the OEB's role establishing TOU rates should be explored before the IESO financially commits to its administered market solutions.

The PWU supports the Report findings regarding the above referenced DER options and recognizes the value of DSM technologies for demand smoothing. It should be recognized that these DER options only represent about 1 GW of potential capacity benefits and these will accumulate over the next 10 years. On an annual basis, the volume of additions that could contribute to system capacity needs is small and disaggregated over many installations.

When considering incentives to consumers, the magnitude of variation between on-peak and off-peak billed electricity costs is far greater from time of use (TOU) (e.g. ~$100/MWh) compared to the HOEP. TOU rates provide many desirable features to consumers, particularly small businesses, and potential aggregators of such services: TOU rates are predictable, stable, and simple, requiring no sophisticated action to take advantage of them.

[35] OEB Market Surveillance Panel, 2018

Studies have shown that a TOU rate approach is an effective mechanism for influencing consumer behaviors and that TOU based incentive scan achieve 70% of the theoretical market-based benefits.[36] If 70% of the value can be captured, that might reduce the above-mentioned benefit of IESO solutions to less than $30M/year.

The OEB is currently piloting new rate program approaches for non-RPP class B consumers and has recently created a new ultralow overnight rate volunteer TOU program for RPP customers.[37]

The role of the OEB in establishing rates was pivotal to the discussion of the FEIWG.[38] The effectiveness of these programs at promoting the highest value DSM approach to adjusting consumer energy consumption patterns for building and residential, including EV charging, should be explored before more complex and costly IESO sponsored energy market innovations are undertaken. Once the effectiveness of the TOU programs has been established, the results can inform a business case for IESO investments in its administered markets to further incent these small-scale DR innovations.

Recommendation #7 - The two most cost-effective mechanisms for minimizing capacity risks in Ontario are not considered in the Report but should be explored: Hydrogen electrolysis and hybrid dual-fuel heat pumps.

During the initial phases of the DER Potential Study, the PWU suggested that it consider the benefits of hydrogen electrolyzers.[39] PWU sponsored analyses show that hydrogen may offer one of the most significant and low-cost opportunities to reduce peaking generation capacity needs, up to 2 GW by 2032.[40]

Ontario's Hydrogen Strategy shows that significant hydrogen electrolyzers capacity is being installed.[41] The Markham Power-to-Gas facility is expected to increase its electrolyzers capacity to 22.5 MW. Aturo's Niagara region facility will have a 20 MW electrolyzers and Aturo is considering a similar scale for its Halton Hills facility. 100% of an electrolysis capacity can be used as demand response at a negligible cost.

Enbridge is advocating for the deployment of dual-fueled natural gas/electric heat pumps to meet Ontario's growing building electrification needs.[42] Analysis show that these devices in conjunction with the hydrogen economy, could cost-effectively reduce winter peak electricity capacity needs.[43]

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[36] MIT Center for Energy and Environmental Policy Research (CEEPR), Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing, Oct 2022.
[37] OEB Non-RPP Class B Pilot Program - Statement of Interest, Oct 6, 2022; EB-2022-0160, Enabling the Implementation of an Ultra-Low Overnight Price Plan; Aug 2022.
[38] OEB FEIWG Report of the BCA Subgroup, June 2022.
[39] PWU Union Submission on the IESO's DER Roadmap Engagement on the DER Potential Study Measures, October 15, 2021
[40] PWU-sponsored study by Strategic Policy Economics, "Electrification Pathways for Ontario", 2021.
[41] Ontario's Low-Carbon Hydrogen Strategy - A PATH FORWARD, April 2022
[42] Enbridge, Pathways to Net-Zero Emissions For Ontario, Sept 2022
[43] PWU-sponsored study by Strategic Policy Economics, "Electrification Pathways for Ontario", 2021.

These low-cost technologies are emerging rapidly and can be expected to have a lower cost than many of the measures examined by the Report.

Closing

The PWU is supportive of the IESO's efforts to evaluate the role DER could play in the future of Ontario's electricity system. However, the PWU supports investments that minimize the electricity costs for all ratepayers.

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 advance innovation across Ontario's electricity system. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable 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, the objectives for supplying low-cost and reliable electricity in Ontario. The PWU looks forward to discussing these comments in greater detail at the IESO's convenience and is willing to provide more in-depth presentations on these findings should the IESO be interested.

Appendix A: Excerpt from **PWU Response to the Ministry of Energy's Request for Information (RFI) on Scoping a Cost-Effective Energy Pathways Study for Ontario**

June 13, 2022

The Power Workers' Union (PWU) is pleased to support the Ministry of Energy's development of a Request for Proposal (RFP) for a Cost-Effective Energy Pathways Study for Ontario. 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 that enhance the competitiveness of Ontario's economy.

The PWU's RFI response to the Ministry reflects the findings of three analyses undertaken by Strategic Policy Economics and their review of state-of-the-art practices at the time each report was prepared. These studies include:

a) Electrification Pathways for Ontario, 2021
b) Distributed Energy Resources in Ontario, 2018
c) Emissions and the LTEP, 2016

These reports are available at www.strapolec.ca/publications and include details on the source materials consulted for each report.

The PWU's comments respond to the Ministry's RFI questions and include several recommendations regarding implications for the proposed RFP.

RFI Questions 2, 3, and 5.

The PWU provides comments collectively in response to the following three RFI questions:

- RFI Question 2. What were key gaps or missing elements in previous pathways studies conducted by you or others in other jurisdictions?
- RFI Question 3. What are the key lessons learned from previous pathways studies?
- RFI Question 5. What are the key considerations for ensuring that a pathway study produces relevant results specific to Ontario's energy system and socioeconomic outlook?

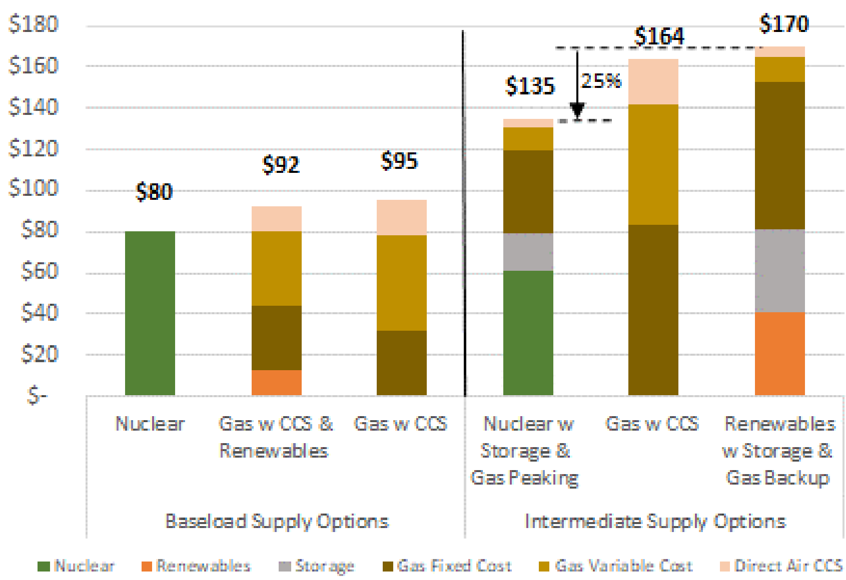
The PWU believes that there are several key considerations that must be adequately addressed by the Ministry's Pathways Study. The analysis should be supported by:

a) Independent, expert, recognized sources of cost information that are readily and transparently available for third-party validation;
b) Fidelity of the electricity system modelling;
c) Optimized total electricity system costing, that captures the benefits of emerging technologies
d) A paced timeline for the adoption of decarbonization solutions;
e) Infrastructure development factors e.g., timeline to develop, site, approve, and build large-scale infrastructure projects.
f) Socio-economic factors such as jobs, GDP, energy security

a) Independent Sources for Cost Information
    a. Several, internationally recognized sources of energy cost information exist for the purposes of such analyses — e.g. U.S. Department of Energy, Energy Information Agency and the U.S. National Renewable Energy Laboratory (NREL). These sources provide transparent, globally recognized, comprehensive data that can help minimize study costs.
    b. A comparison of the forecast cost trends from several sources helps explain and justify the cost assumptions (or ranges) used for a study. The consistent use of major assumptions among Ontario studies, e.g. climate, energy and economic, would be beneficial. Currently, the IESO has indicated that it will be using NREL data in its pathways' analysis.
    c. A common observation from the review of several studies indicates that many analyses, do not adequately adjust cost information reflective of local conditions e.g., weather, domestic content, exchange rates, local labour rate and other cost factors (ref Appendix 1).
    d. *RFP Implications:*
        i. The RFP should require participants to source, expert, independent, publicly available energy cost data e.g., the U.S. National Renewable Energy Laboratory (NREL).
        ii. The RFP should require that the cost assumptions reflect and model "Ontario-specific" conditions.

b) Fidelity of the electricity system modelling
    a. The single most prominent area of debate or difference among climate studies is the inadequate modelling of the integration costs of various energy sources into the electricity system, particularly for renewables.
    b. Integrating renewables into Ontario's system is significantly impacted by weather induced intermittency. Furthermore, the extent of the economic and environmental impacts caused by this intermittency is dependent upon the available supply mix.
    c. Cost impacts can be mitigated in part when integrated with natural gas generation in the supply mix. When integrated with Ontario's nuclear and hydro supply mix, renewables are less cost effective.
    d. Appendix 1 examines the factors impacting the integration of intermittent renewables with storage and natural gas. This requires a detailed full 8760-hour high fidelity model to properly develop these factors as described more fully in response to RFI Question 4 below.
    e. Studies by Strategic Policy Economics have consistently shown that new nuclear represents the lowest cost option for baseload. It is also the lowest cost option for meeting daytime fluctuations in demand as indicated by the figure below.
    f. *RFP Implications:*
        i. The RFP should require participants to demonstrate their capacity and capability to develop a full 8760-hour annual demand and supply forecast that accurately reflects renewables output in Ontario and provincial demand. There should be no averaged daily, weekly or monthly profiles in the simulations.
        ii. The simulations/models should accurately reflect the operating limitations of storage devices to help identify the required storage capacity and/or backup generation capabilities for any supply mix scenarios.

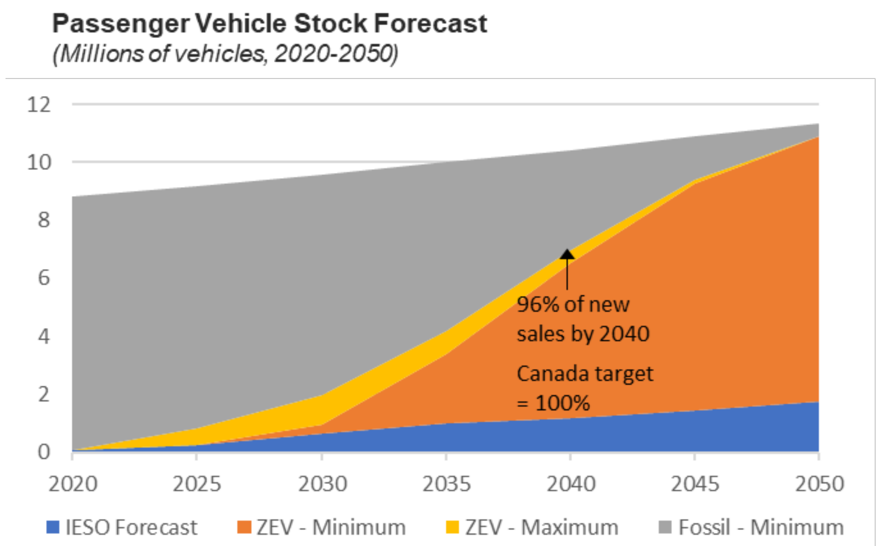
Future Non-emitting Electricity Costs
Nuclear vs. Gas & Renewables-based alternatives
($/MWh 2018CAD, 2035 Installations)



c) Optimized total electricity system costing, that captures the benefits of emerging technologies
   a. Emerging demand side management technologies can help reduce investments in Ontario's required electricity system infrastructure. These include:
      i. Energy management systems for buildings to help smooth demand throughout the day;
      ii. Bi-directional EV charging that enhances energy management systems; and,
      iii. Dual-fuel heat pumps that use natural gas for peak winter days and help reduce the need for the electricity system to supply winter heating peaks.
   b. Electrolytic-produced hydrogen can provide several demand response services and potentially, eliminate the need for gas-fired generation.
   c. These innovations can reduce systems peaks, maximize baseload power delivery on the bulk system and enable municipalities to develop non-emitting peak energy solutions in their jurisdictions.
   d. RFP Implications:
      i. Participants should be asked to examine the aforementioned "state of the art" emerging technologies, their potential for demand smoothing, and how they may reduce the need for costly peaking supplies.
      ii. Participants should have the capability to model the impacts of these technologies on demand and their incorporation in the participant's detailed simulations of the electricity system supply mix.

d) A paced timeline for the adoption of decarbonization solutions
   a. A limitation in the IESO's current forecast is its under estimation of the adoption rate of emission reducing technologies.
   b. Current forecasts suggest that 100% of the new vehicles sold in Ontario by 2035 will be EVs – with supports from the federal government's climate plan and auto sector investments in

EVs. The Figure below illustrates an adoption forecast prepared before the federal target for 2035 was set. A more realistic adoption assumption for 2030 may be closer to the yellow line. The blue colour reflects the IESO's assumptions.



Sources: Princeton University, 2020; Deloitte, 2020; BNEF, 2020; Strapolec Analysis

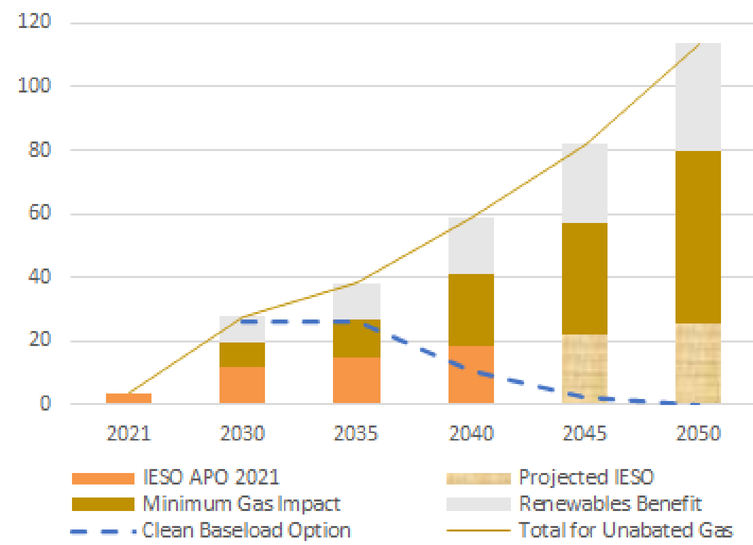
c. Other factors will also impact technology adoption e.g. incentives, like the Industrial Conservation Initiative (ICI) program.
    i. Under the ICI program, heat pumps and hydrogen electrolysis are already cost-effective options for businesses that are Class A electricity consumers.
        1. However, the economies enjoyed by the Class A consumer results from the transfer of costs to residential and other Class B electricity consumers.
    ii. These incentives could also help accelerate building and heavy-duty vehicle decarbonization, neither of which, is considered by IESO's 2021 reference demand case.

d. RFP Implication:
    i. The RFP should request that an assessment of the penetration rates of various decarbonization options be undertaken that reflect the policy and rate programs that are specific to Ontario's electricity system (e.g. Time of Use and ICI).

e) Infrastructure development factors e.g., timeline to develop, site, approve, and build large-scale infrastructure projects.
    a. Ontario faces the significant risk that rapid growth in electricity demand will outpace the capacity of the province's electricity system to meet it. A conservative estimate identifies a supply need of 70 GW by 2050. This is 55 GW more capacity than is currently provided by Ontario's existing 15 GW hydroelectric and nuclear fleet. Ontario will require a significant infrastructure build-out program to mitigate this risk.
    b. Pathways to decarbonization cannot be realistically described without considering the project timeline implementation implications of the options available.
    c. The following Figure shows that Ontario's electricity sector emissions may increase significantly to 2050. Increases to 2035 are unavoidable. If Ontario takes decisive action soon to develop new non-emitting resources, then electricity system emissions may begin to decline after 2035.

Forecast Emission Scenarios for Ontario's Electricity System

(Mt CO_{2e})



d. Regardless of the type of energy supply being built, each faces a unique set of challenges.
   i. Is CCUS a viable option for Ontario? How much and by when will capture, transport and storage infrastructure be available?
   ii. Are large quantities of commercially viable sites for new wind and solar generation available? What are the costs of back-up grid scale storage and gas-fired generation? What are the cost implications of decommissioning expiring wind and solar contracts?
   iii. New conventional nuclear could take 10 to 15 years to develop. Ontario Power Generation's Darlington site is currently licensed for 4800 MW but there are no current plans to leverage that full capacity.
   iv. New large-scale hydroelectric development opportunities are limited in Ontario and new investments will involve higher development costs for plant and associated transmission network. Additional factors include Reconciliation, flooding, adjacent land uses, natural environment etc.

e. RFP Implications:
   i. Participants should be asked to provide implementation perspectives on the schedule, costs, and other implications of Ontario's pathway options including: siting and land use, technological maturity, environmental assessment, licenses, social license and Indigenous considerations.
   ii. The emissions trajectories developed for each pathway option should be presented and contrasted.

f) Socio-economic factors such as jobs, GDP, energy security

a. An optimal decarbonization pathways for Ontarians would provide the province's businesses with a competitive advantage that grows the economy, attracts investment and creates jobs.
b. Natural gas options coupled with CCUS means importing significant amounts of energy from the U.S. This exports Ontario dollars instead of making investments in home grown

infrastructure such as new nuclear and hydro, that can grow the province’s economy and create sustainable local jobs.

c. Energy security, especially based on low-carbon resources, has a higher policy profile given recent global events – the war in Ukraine and shift in global supply chains. Ontario’s growing reliance on imported natural gas is also exposing the province’s energy security to more risk. Two new developments – the Enbridge Line 5 dispute with the State of Michigan; and increasing LNG exports from the U.S. to Europe -- can have impacts on supply and price for Ontario consumers.

d. *RFP Implications*:
    i. Participants should characterise the domestic content of the development and operation of the energy alternatives being proposed. Domestic content directly relates to the jobs created in Ontario and the overall energy GDP trade balance for the province.

RFI Question 4. Do you have a model that would be relevant to this work and if so, how does it work?

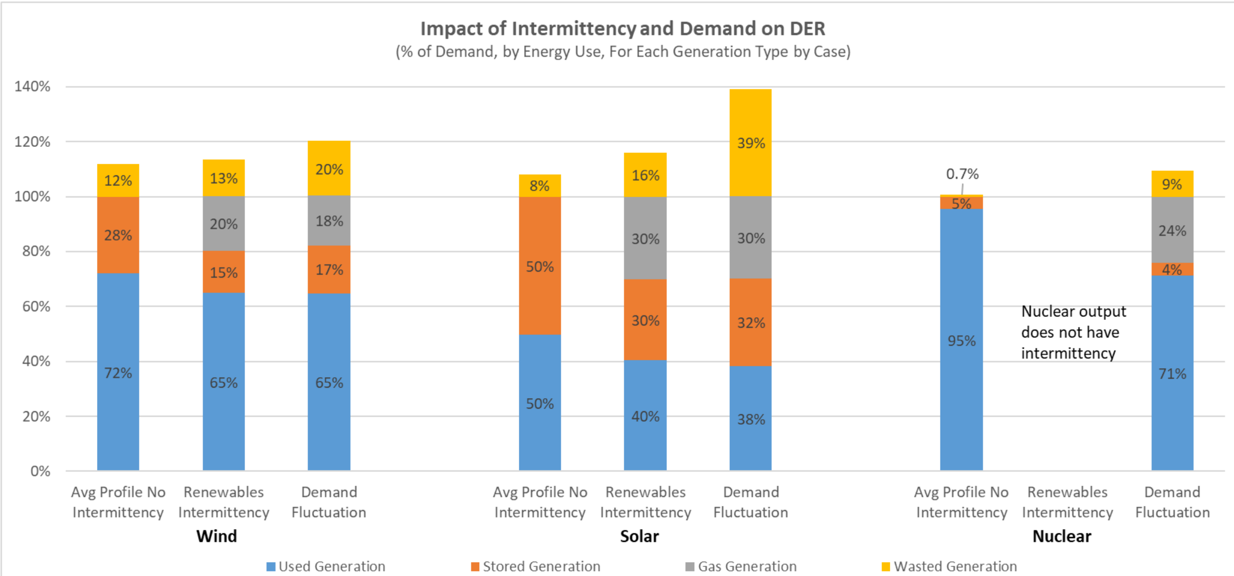
Strategic Policy Economics has developed detailed Ontario-specific models that accurately reflect the interaction of hourly demand fluctuations with the flexibility of gas, hydro, and storage resources and the intermittency and seasonal variations associated with the output from renewables. A full year 8760-hour profile of actual renewables output and real demand is required to properly reflect the performance and contributions from Ontario’s renewable resources.

Model fidelity more accurately captures the full system cost of integrating renewables in the system. The need for backup gas generation and any excess generation that is wasted can be significantly underestimated, without having data on the daily variability in hourly demand and intermittency throughout the year.[44] The detailed modeling approach described in Appendix 1 has been recommended to the IESO for inclusion in its pathways study.

The following figure shows the performance implications of over-simplifying the analysis. When comparing a fully modeled solar solution to simplified models often found in other studies,[45] the higher fidelity models show that: 40% of the solar output might be wasted; storage costs could double as only half of their capacity is utilized; gas-fired generation is still required to supply 30% of the generation; and, provide almost all of the peaking capacity.

[44] Strapolec, Renewables-Based Distributed Energy Resources in Ontario, 2018.

[45] Hans-Kristian Ringkjøb, et al., “A review of modelling tools for energy and electricity systems with large shares of variable renewables”, 2018, Renewable and Sustainable Energy Reviews; Miguel Chang a, et al., “Trends in tools and approaches for modelling the energy transition”, 2021, Applied Energy.


Impact of Intermittency and Demand on DER
(% of Demand, by Energy Use, For Each Generation Type by Case)
140%
120%
100%
80%
60%
40%
20%
0%
12%
28%
72%
13%
20%
15%
65%
20%
18%
17%
65%
8%
50%
50%
16%
30%
30%
40%
39%
30%
32%
38%
0.7%
5%
95%
Nuclear output does not have intermittency
9%
24%
4%
71%
Avg Profile No Intermittency
Renewables Intermittency
Demand Fluctuation
Wind
Avg Profile No Intermittency
Renewables Intermittency
Demand Fluctuation
Solar
Avg Profile No Intermittency
Renewables Intermittency
Demand Fluctuation
Nuclear
Used Generation
Stored Generation
Gas Generation
Wasted Generation

Appendix 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.[46]

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.

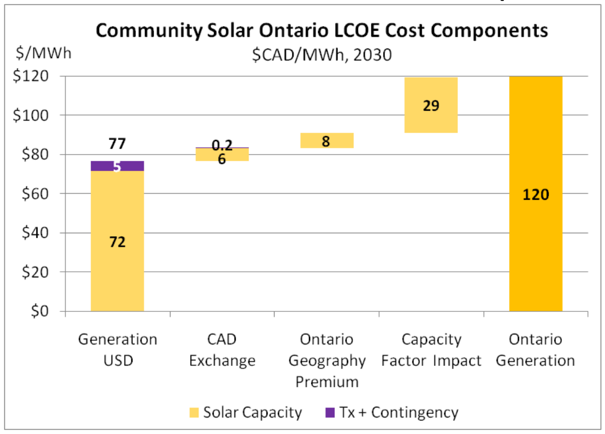
Jurisdictional Premiums

Several factors must be considered when adopting LCOEs from published sources given the underlying assumptions will be different as illustrated by Figure 2:[47] 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.

[46] EIA AEO, 2021 Table 1a

[47] 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. [48] Figure 2 reflects an assumption that Ontario cost premiums versus the published LCOEs can be expected to be similar to those in neighboring states.

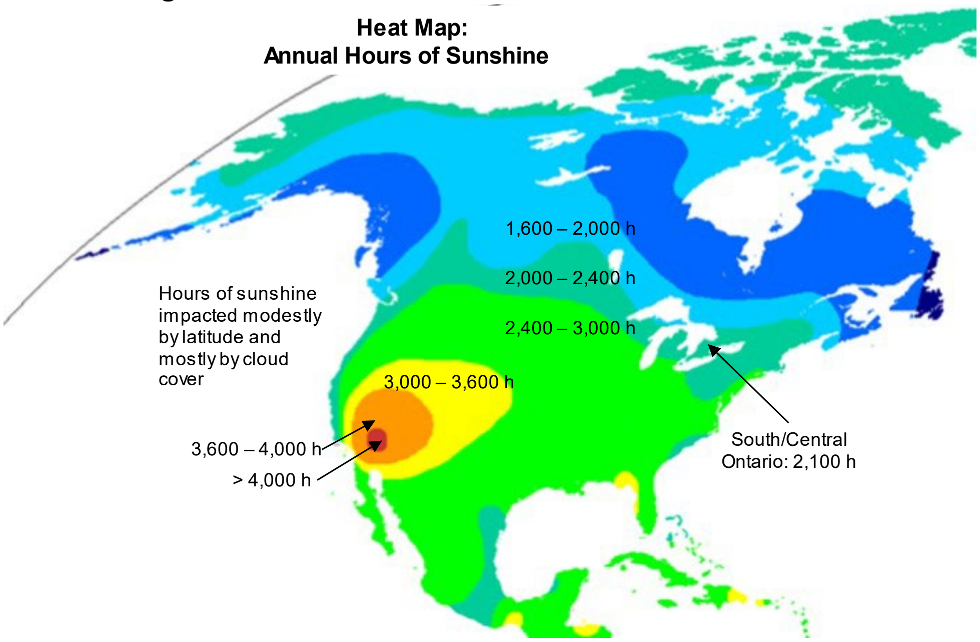
iii) Capacity Factor

The capacity factors for variable renewable energy (VRE) range significantly reflecting geographic based variations in weather. Associated LCOE values should be prudently adapted from one region to another. 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 by Figure 3--[49] , more than double 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 the Arizona solar installations. Halving a capacity factor doubles the LCOE.

[48] EIA, 2017

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

Figure 2: Annual Hours of Sunshine Across North America



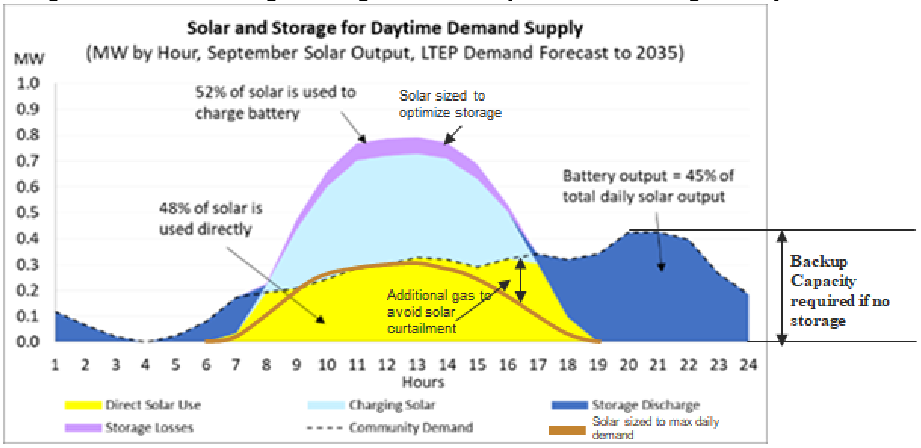
Profile Costs

The cost of backup resources for non-dispatchable generation, such as for VRE, is often referred to as the "profile cost". This 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:[50]

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 for use when demand would otherwise exceed VRE output.

[50] 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.

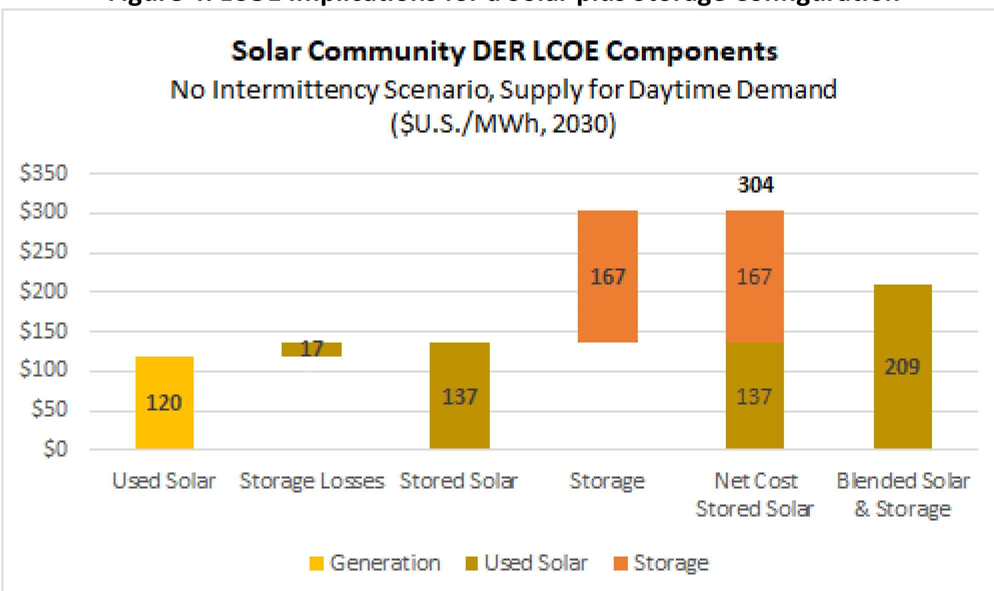
Levelized Cost of Storage (LCOS)

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.[51] 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 five times the average output of the VRE due to intermittency (e.g. grid scale solar capacity factors in Ontario are less than 20%).[52] Similarly, distribution system costs may also be impacted.

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

[52] IESO Power Data; Strapolec Analysis

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.

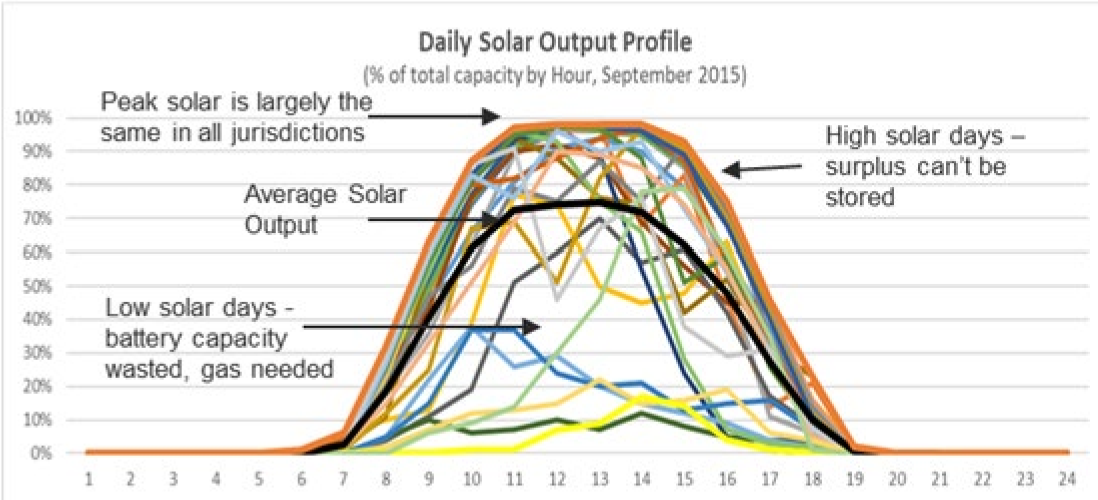
Strategic Policy Economics' analysis explores these considerations that impact the fidelity of any required system modelling. [53]

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.

[53] Strapolec, DER in Ontario, 2018.

Figure 5: Sample Daily Solar Output Variations

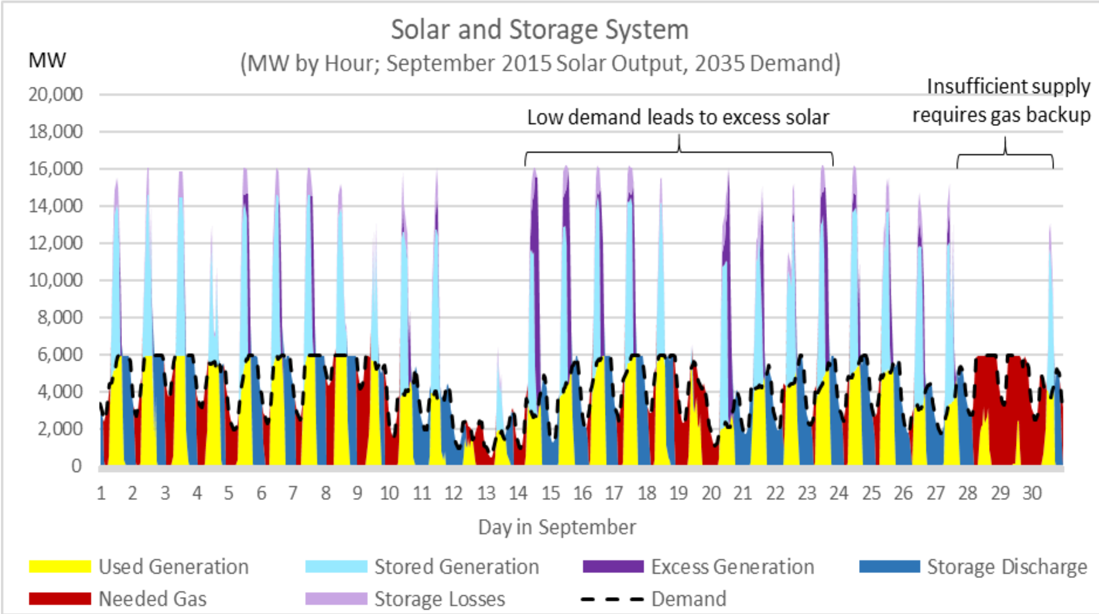


Even when paired with storage, this intermittency, on some days, can lead to insufficient solar generation to fully charge a battery, thereby wasting the capacity of the battery and requiring backup generation. On other days, there may be more than optimal sunshine causing output to exceed demand and/or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

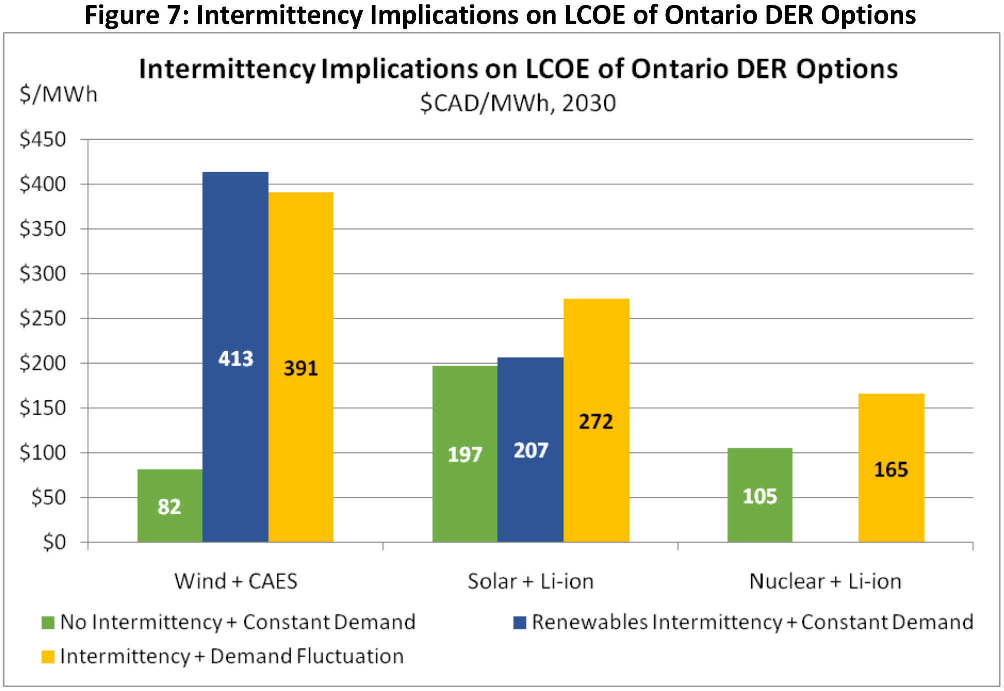
Figure 6: Sample Daily Solar Output and Demand Variations



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