AUG 2022

Regional Planning Process Review – Non-Wires Update

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Agenda

- Objective
- Background
- Hourly Demand Profiling Methodology
- Non-Wires Options Analysis Methodology
- Next Steps

Objectives

- To recap the Integrated Regional Resource Plan (IRRP) non-wires alternative (NWA) analysis process changes presented in the fall 2021 webinar
- To provide further information and seek feedback on:
  - Hourly Demand Profiling Methodology
  - Options Analysis Methodology: Feasibility, Sizing, and Cost-Effectiveness of NWAs

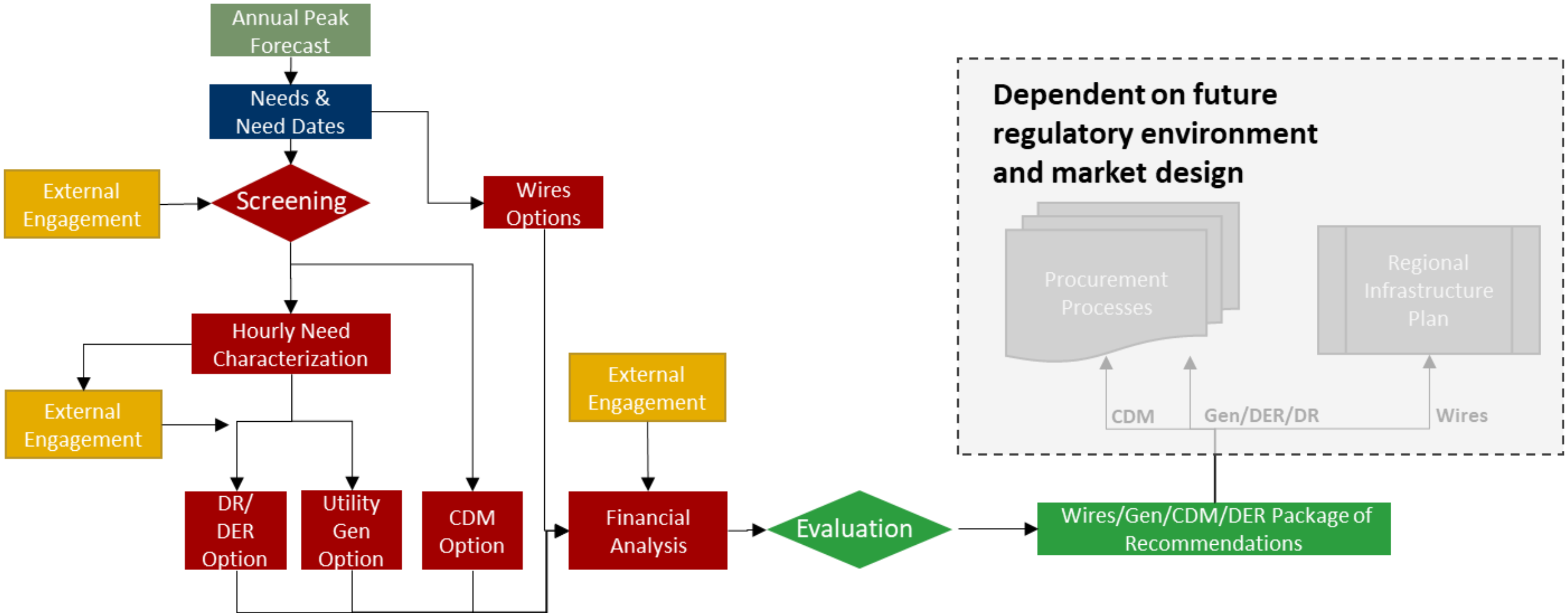
Background

- The IESO completed the Regional Planning Process Review in early 2021
- This initiative included identifying:
  - Key areas in the process for enhancement
  - Potential barriers to implementing NWAs in regional planning
  - A coordinated, cost-effective, long-term approach to replacing transmission assets at end-of-life
- The final report details various recommendations to improve the regional planning process
- The IESO and OEB collaborated to identify the organization responsible for the review and implementation, if appropriate, of each recommendation
- Implementation of process improvements for the consideration of NWAs during IRRPs is IESO-led

Recap: October 2021 Webinar

- At the Oct 2021 webinar, the IESO provided an update on the implementation of recommendations from the Regional Planning Process Review, including those to help address barriers to NWAs in regional planning
- The IESO sought stakeholder feedback on the draft process, proposed screening mechanism, tools used to consider and evaluate NWAs, and NWA engagement in IRRPs

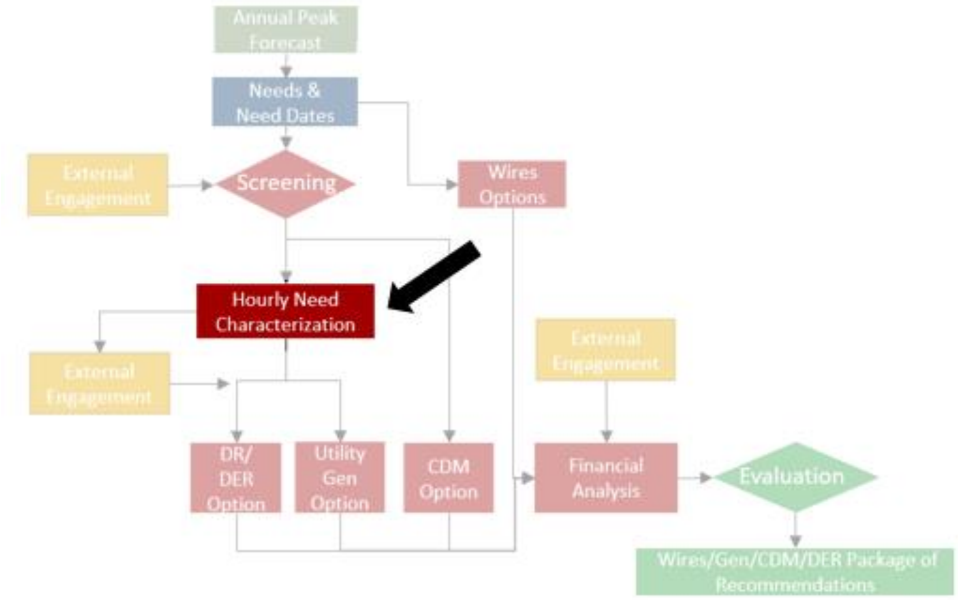
Recap: IRRP Process Diagram



Hourly Demand Profiling Methodology

Recap: Hourly Needs Characterization Purpose

- Studying peak demand hours is sufficient for sizing wires options because they are generally available in all hours once in service
- Evaluating the feasibility of NWAs, particularly energy-limited dispatchable options, require needs to be quantified in greater granularity (duration, frequency, magnitude)
- The first step is to create hourly demand profiles to better understand reliability needs in all hours of the year



Demand Profiling for IRRPs

- Demand profiles can be created for any subset of the system downstream from a particular transmission constraint of interest
- For example, demand profiles can be created for:
  1. A single transformer station (e.g. for station capacity needs)
  2. Aggregate of multiple stations in a constrained subsystem
  3. Aggregate of entire zones/regions surrounding a system interface of interest

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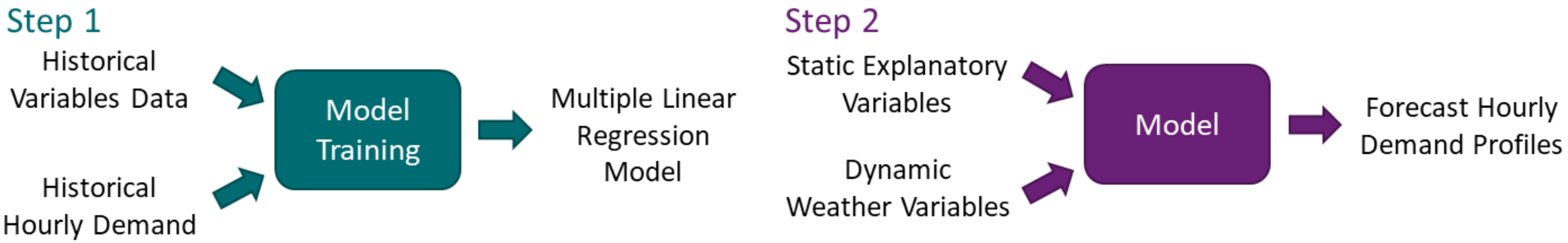
Demand Profiling Methodology Overview

- Hourly demand profiles are created by first training a linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles



- These hourly profiles can then be scaled to match the IRRP peak demand forecast

Linear Regression Model Training

- The multiple linear regression model is used to develop a relationship between historical hourly demand and predictor variables including:

Weather & Calendar Variables

- Temperature
- Cloud cover
- Humidity
- Wind chill

Non-Weather Variables

- Population
- Employment
- Other economic predictors
- COVID Impacts
- Global Horizontal Irradiance (to capture embedded solar impacts)
- Calendar (day of week, holidays)

Model Application: Non-Weather Variables

- Projections of non-weather variables may be taken as inputs to the model and do not change between model runs
  - These projections are also used in the IESO's Reliability Outlook and come from a variety of sources:
    - Demographic variables: Forecasts from the Ministry of Finance
    - Economic variables: Forecast providers (such as the Conference Board, Centre for Spatial Economics, etc.)
- These variables help characterize the load in question over the forecast period

Model Application: Weather Variables

- Weather and its interplay with variables like calendar and time of day has a significant impact on electricity demand
- Furthermore, different permutations of weather variables can create a diverse range of possible outcomes
  - For example, the impact of an extreme heat event may be blunted if it occurs on a statutory holiday versus a weekday
- Therefore, it is not enough to simply capture a range of forecasted weather but also a range of weather permutations
- The model uses 31 years of historical weather data with various calendar permutations to generate different demand profiles
- To ensure that the full extent of the weather impact is captured, the weather variables permutated with calendar variables by shifting them 7 days ahead and behind
- This results in a total of 465 profiles generated

Example: 2017 Weather Data (Celsius)

Shifted behind 7 days ← → Shifted ahead 7 days

2017_B7	2017_B6	2017_B5	2017_B4	2017_B3	2017_B2	2017_B1	2017_A0	2017_A1	2017_A2	2017_A3	2017_A4	2017_A5	2017_A6	2017_A7
5.62	1.2	0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43
1.2	0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27
0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02
-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25
-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22
-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22	-11.36
-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22	-11.36	-7.5

* For illustrative purposes only

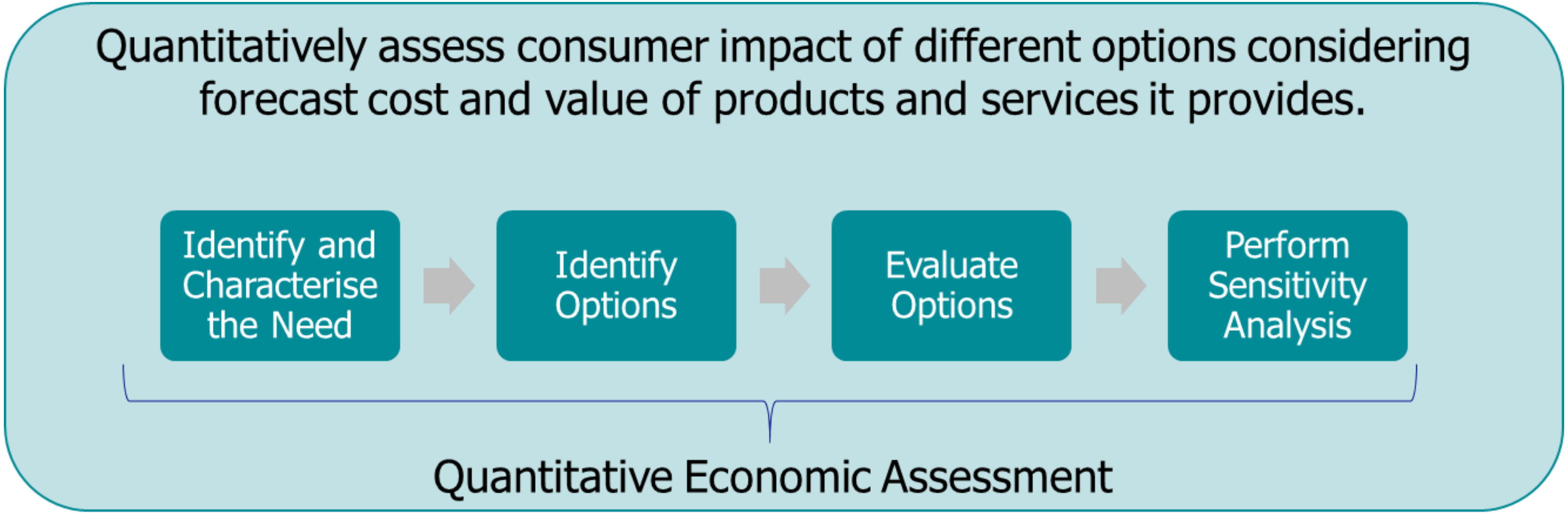
Profile Selection

- Profiles are ranked according to energy
  - Note that all profiles generated are scaled to the same IRRP peak demand forecast
- Three representative profiles are used in IRRPs:
  - 97^{th} percentile (high energy; profile is "smoother")
  - 3^{rd} percentile (low energy; profile is "peakier")
  - 50^{th} percentile
- Typically, the 50^{th} percentile profile is used in the IRRP's NWA options analysis as described in the following section
- The choice in profile influences the technical requirements and costs associated with NWAs
- In cases where the cost difference between traditional wires and NWAs are close, the 97^{th} and 50^{th} percentile profiles may also be used for sensitivity analysis

Non-Wires Options Analysis Methodology

Options Analysis Overview

- Economic assessments evaluate transmission and resource options to meet regional or system reliability needs



Identifying & Characterizing the Need

- IRRP's technical studies identifies needs for improving capacity, security and reliability of electricity service
- A high-level screening mechanism helps identify the subset of needs where NWAs are potentially suitable (further details in Oct 2021 webinar)
- For each need where NWAs are potentially suitable, the demand profiling methodology described in the previous section is used to characterize the need and inform options analysis

Identifying Options

- Identifying viable options takes into consideration the following:

Maximizing the use of existing infrastructure and resources in the region (i.e. merchant generation, generators with expiring contracts, etc.)

New transmission facilities and/or lines to deliver provincial resources.

New generation/storage with the attributes that most closely meet the need

Demand Response (DR) or Energy Efficiency (EE) measures

Integrated solutions with combinations of any of the above options

Selecting Options

- The efficacy of EE measures to address the need is based on Achievable Potential Studies (APS) that quantify how much savings can be realized and at what incremental cost
- The efficacy of generation and storage options are based on power capacity and energy requirements, Loss of Load Expectation (LOLE), Energy Not Served (ENS) profiles, and generator capacity factors
- The efficacy of DR is based on past Capacity Auction offer information and Distributed Energy Resources (DER) APS that quantify how much cost-effective DR can be realized
- The following slides will describe how these options are selected, sized, and compared
- In general, potential options that are known to satisfy key technical requirements and have the lowest cost tend to be preferred

Demand Response Options

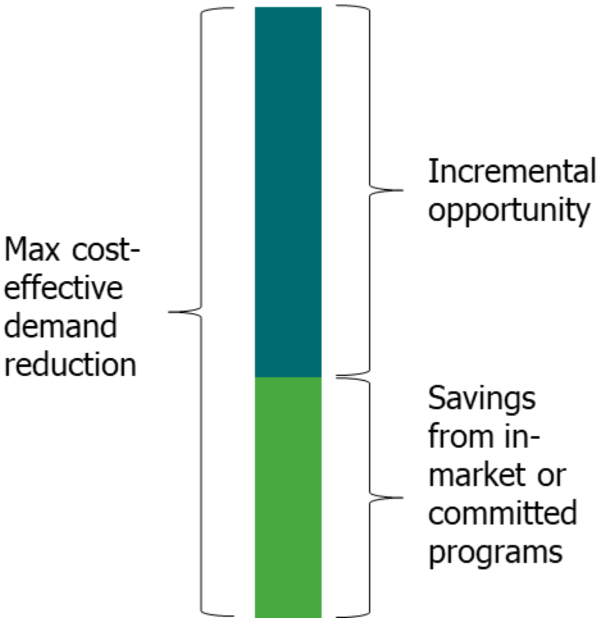
- DR potential has been difficult to quantify in the past
- Typically use past auction offer information to assess cost-effectiveness, however some issues arising from this approach are offers made previously are based on the capacity product at the time, available supply of DR and target capacity can change, etc.
- In 2021, the IESO commissioned Dunsky Energy and Power Advisory to develop a DER APS that highlights the types and volumes of DERs likely to emerge in Ontario over a 10-year timeframe that is both achievable and economic
- This study, in combination with historic auction offer information and DR contribution to local adequacy, are now considered when assessing DR potential

Energy Efficiency Options – Achievable Potential Study

- In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)
- The main objective of the APS is to identify and quantify potential energy savings (electricity and natural gas), GHG emission reductions and associated costs from demand side resources for the period from 2019-2038
- The study shows a significant and sustained potential for energy efficiency across all sectors and is used to inform:
  - Future energy efficiency policy and/or frameworks
  - Program design and implementation
  - Assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning

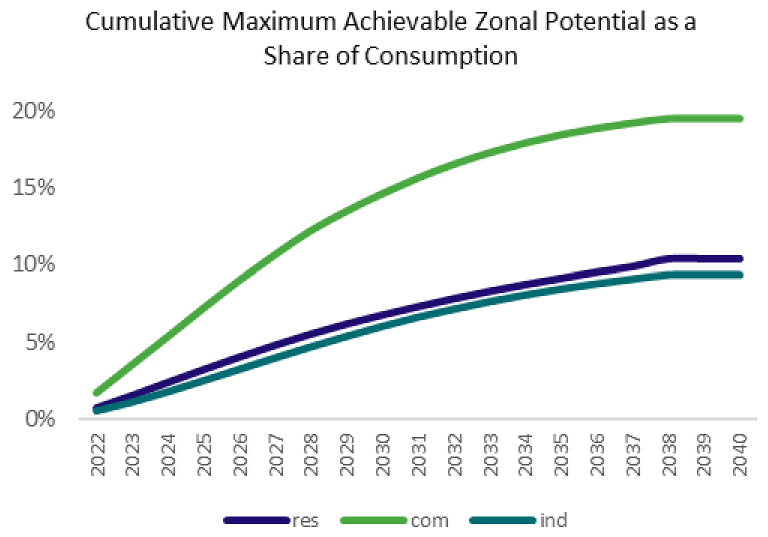
Energy Efficiency Potential Analysis

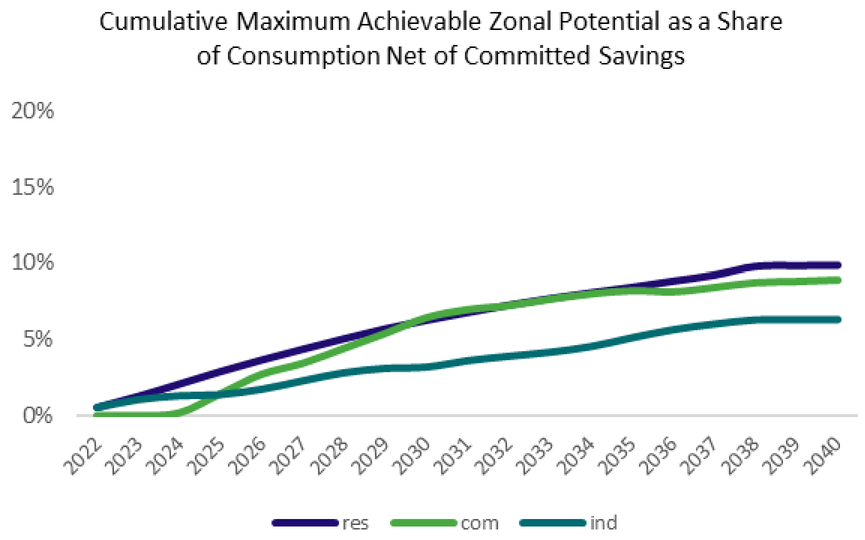
- Based on APS results, the maximum amount of provincial system cost-effective demand reduction for each of the 10 transmission zones in the province can be calculated
- The expected savings from provincial and federal programs that are currently in-market or have committed budgets and targets including the 2021-2024 Conservation and Demand Management framework are already accounted for in the IRRP demand forecast and are subtracted from the maximum achievable demand reduction
- The difference represents the estimated incremental opportunity that could be targeted in any given area



Energy Efficiency Potential Example

- Figures below illustrate an example of the maximum total and maximum uncommitted savings opportunities calculated for the Niagara transmission zone





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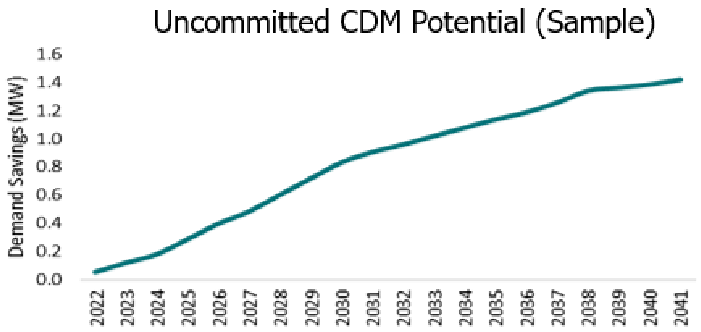
Station-level Energy Efficiency & Cost Estimate

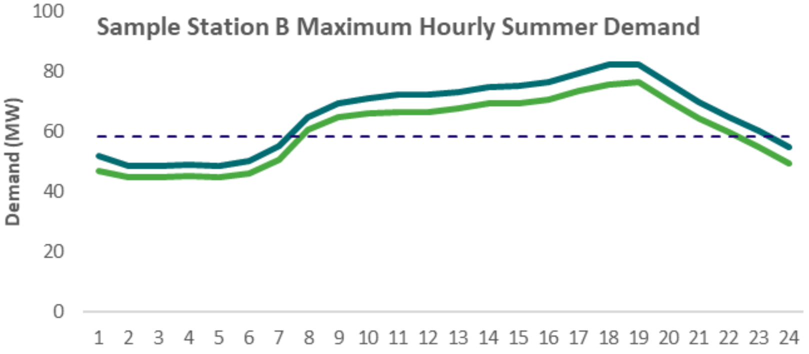
- These zonal potential savings calculations are then applied at the station level to understand the cost effective achievable savings that can be targeted to reduce load and potentially defer a regional or local wires need or support a wires solution
- The estimated cost to deliver these savings is also calculated based on the average zonal APS results
- The next figure illustrates the potential at a distribution station in Niagara as an example

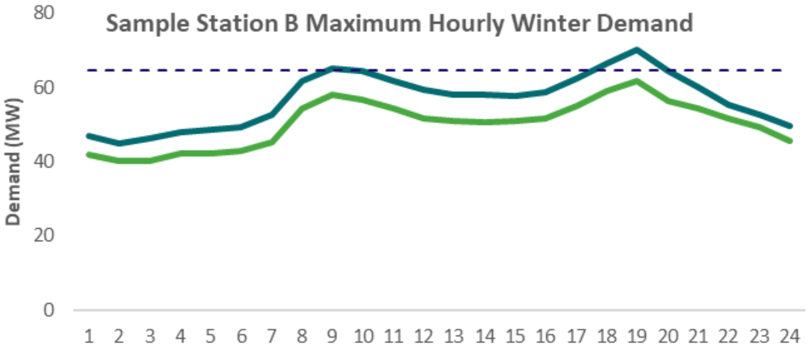


Sample Station A	2027	2041
Net Forecast Demand (MW)	13.7	16.6
Max Achievable CDM Potential (MW)	0.9	2.1
Committed CDM Potential (MW)	0.4	0.7
Uncommitted CDM Potential (MW)	0.5	1.4

Station-level Hourly Demand Savings Estimates

- Uncommitted CDM savings potential is also deducted from the station-level hourly demand profiles to create modified hourly demand profiles
- Where CDM cannot meet the full need in every hour, these modified profiles are used to size solutions for other non-wires technologies (e.g., storage, distributed generation, DR) to create integrated NWA packages



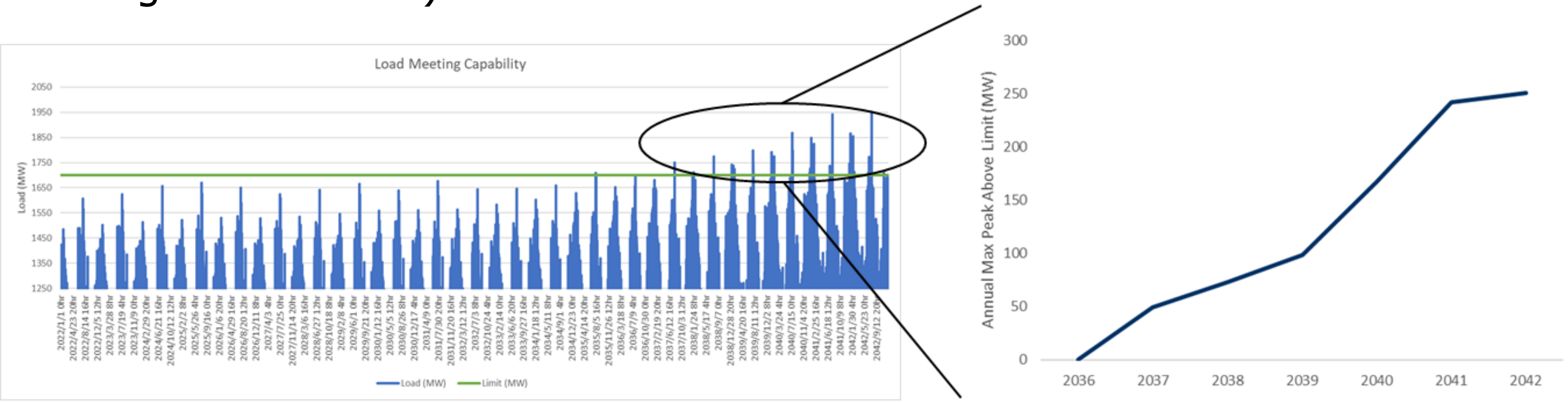


Energy Efficiency Implementation

- The IESO looks for input from the Technical Working Group in a given region to refine these assumptions and explore options to target system cost effective EE in the region
- The Local Initiative Program, under the 2021-2024 CDM Framework, is one tool available to target delivery of additional CDM savings to specific areas of the province with identified system needs
- A review of the opportunity for CDM to be targeted to address regional or local needs and available tools to do so under the current framework is underway as part of the 2021-2024 CDM Framework Mid-Term Review
- The IESO is also working to refresh the APS modeling to incorporate updated demand and avoided cost assumptions; results are planned to be shared via a public webinar in late 2022

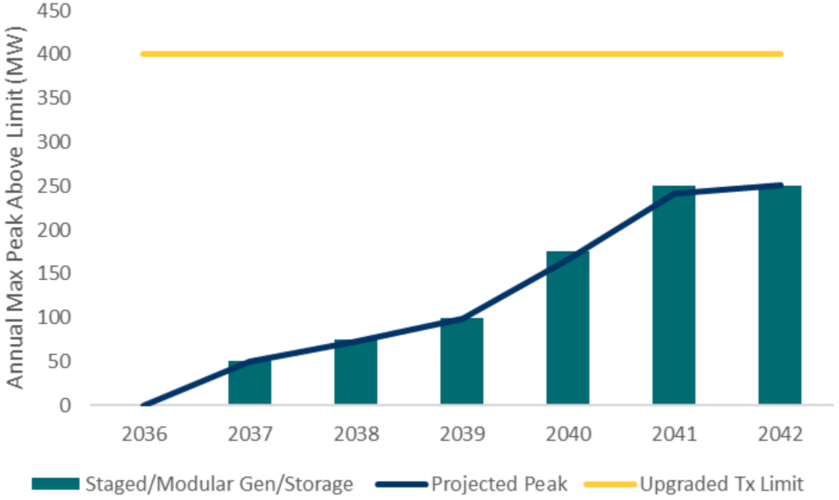
Generation & Storage Options

- The technology type and sizing of generation and storage options are determined by the characteristics of the need
- The need characteristics are quantified by the energy-not-served profile – the forecast hourly demand above the load meeting capability (amount of demand that can be served by existing infrastructure)



Energy-Not-Served: Options & Timing

- Once built, traditional wires options generally increase the load meeting capability across all hours for the entire forecast horizon
- Generation and storage options are more modular and can be deployed in discrete blocks as demand grows
- The ENS profile is not static over the planning horizon; the capacity (MW) and energy (MWh) requirements evolve as demand grows and influences the feasibility and economics of various generation and storage options



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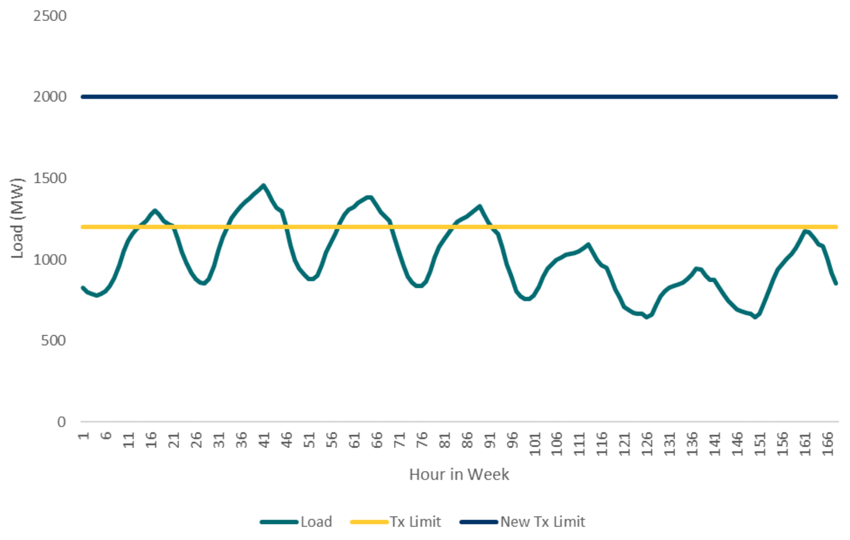
Energy-Not-Served: Sizing Options

- Whereas wires solutions and non-energy-limited resources can primarily be sized based on the capacity requirements alone, energy-limited resources must also consider the energy requirement and temporal patterns
- The following slides explore the sizing of storage and variable generation options to illustrate the complexity of using energy-limited options to address local reliability needs



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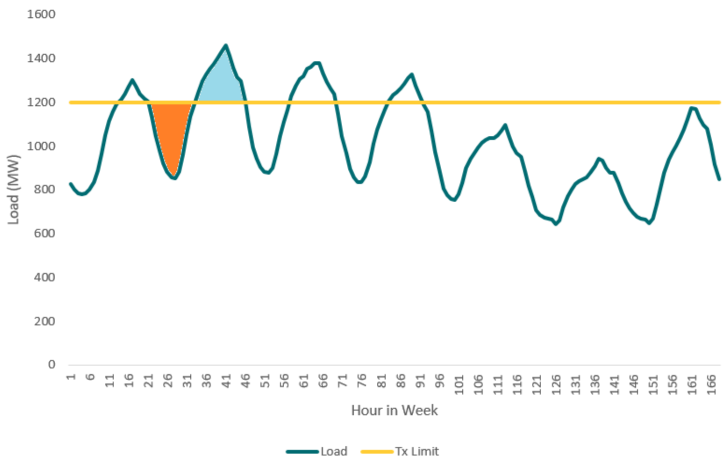
Sizing Storage Options

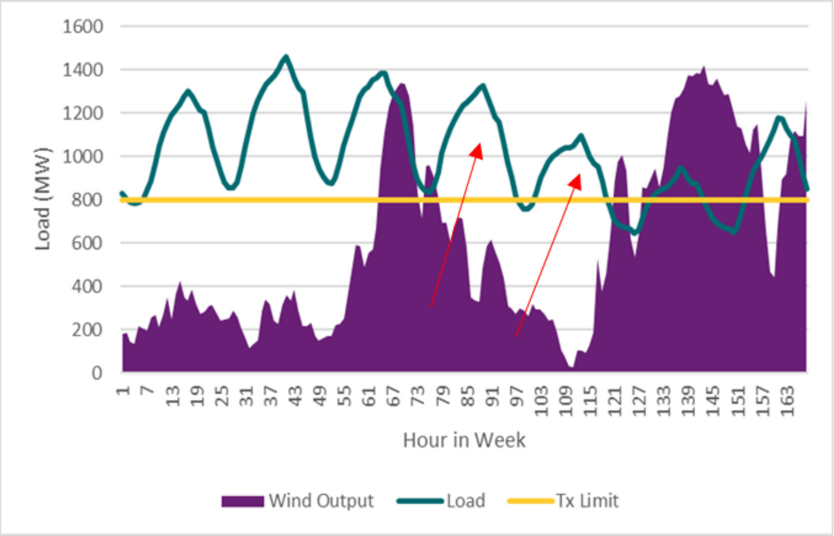
The storage facility needs to be able to "peak shave" the local load profile (teal) such that it never exceeds the Tx Limit (yellow).



- The orange area represents the amount of energy that the storage could charge overnight, while the blue area is the amount (and shape) of energy that needs to be delivered the next day
- The energy storage facility is sized such that the reservoir has enough storage capability to charge up enough energy (MWh) overnight, and inject it the next day, with enough power capacity (MW) to shave the peak.

Sizing Variable Generation + Storage Options

- In the example on the right, there is not enough transmission capacity to allow the storage to charge off-peak
    - Additional energy from a wind source is required
- Some of the wind energy happens to be produced when it is needed, however, storage must be sized such that it can soak up excess wind that is not coincident with the need and deliver it when needed.
- This approach finds the least-cost combination of generation + storage that can satisfy the local needs



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Limitations of Sizing Energy Limited NWAs

- This approach is very sensitive to the shape of both the demand and variable generation forecast. When and how much energy is available, and when it is needed greatly impacts the size of storage (and VG) required
- This is a deterministic approach to a very stochastic problem: there is significant demand forecast and wind forecast uncertainty, especially at the 1-hour interval level
- Future improvements could include characterizing the forecast uncertainties and performing a Monte Carlo type simulation to generate a distribution of optimal sizing outcomes.

Evaluating NWAs: Cost Comparison

- The NWAs should aim to cost-effectively meet the need on an equivalent reliability basis
- There are a few tools and methods available to assess cost-effectiveness, but ultimately we want an approach that allows for an apples-to-apples comparison of all options
  - Comparing the same dollars, to the same need (size and timing) and providing the same level of reliability/performance.
- Other qualitative attributes (i.e. ability to quick start, fast ramp rates, flexibility in operation, dispatchable, etc.) should be considered as well

Levelized Unit Energy Cost

- The Levelized Unit Energy Cost (LUEC) is the average price an electricity generator/storage facility must receive for each unit of energy it generates over its lifetime to break even.
- Model used to calculate LUEC of alternative generation/storage options considers factors such as overnight capital costs, fixed O&M costs, variable O&M costs, fuel management fees, etc.)
- NWAs are often compared in levelized energy costs ($/MWh) or levelized capacity costs (either $/kW-yr or $/kW-mo)
- This provides a means of assessing alternative options for planning purposes and is generally used as a screening tool to shortlist resources for more detailed analysis.

Variables Considered

Information	Description
Project life	The time horizon over which cash flows will be considered and the project costs will be amortized.
Overnight capital cost	The cost of constructing a project as if it could be performed the same day (this does not include the interest incurred from borrowed funds during the construction period).
Fixed OM&A	The operational, maintenance and administration costs which do not depend on production.
Variable OM&A	The operational, maintenance and administration costs which depend on production.

Discounted Cash Flow Analysis

- Discounted Cash Flow (DCF) analysis finds the net present value (NPV) of expected future cash flows of the resource cost and system benefit by using a discount rate
  - Future cash flows are "discounted" at a rate that reflects the time-value of money and the inherent risk associated with future uncertainty

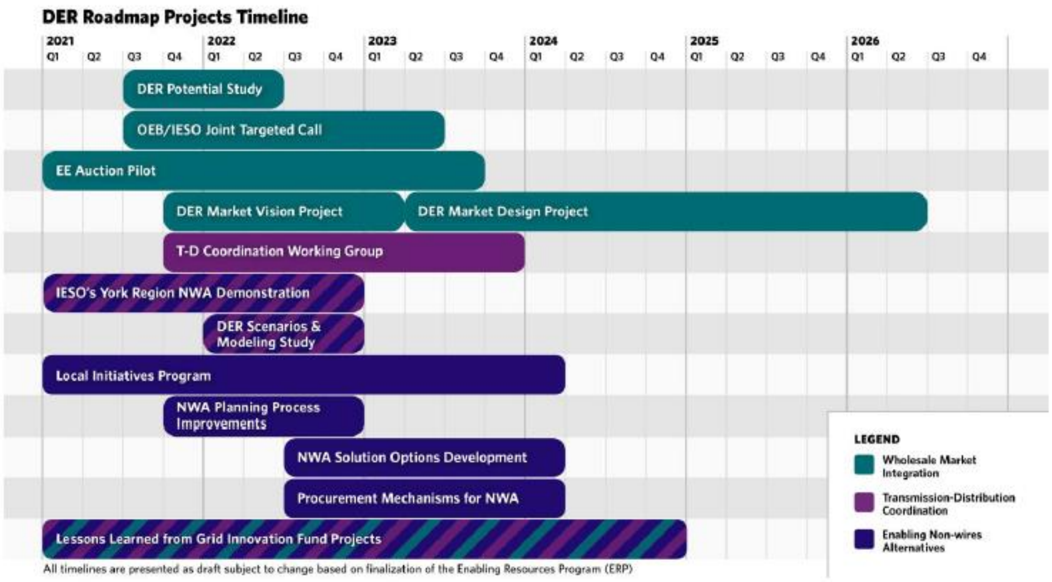
- A DCF model is made for each option, which at a minimum includes the following considerations:
  - Cost of the option (i.e. LUEC) amortized across its lifetime
  - Bulk system energy and capacity benefits (currently valued at an estimate of the cheapest cost of new capacity)
    - Note that the wires option also accounts for the cost of system resources delivered

Sensitivity Analysis

- Transmission projects require a longer lead time than generation so transmission investment decisions often need to be made without knowing what resources will clear capacity markets or the locational value of energy and capacity
  - As markets mature, information about locational capacity/energy value will improve and help inform options analysis
- In the interim, key inputs like locational capacity/energy value can be varied to better understand if/how the preferred solution could change under a reasonable set of alternative assumptions

Next Steps

The IESO's DER Roadmap



- NWA process improvements for IRRPs complements other ongoing work as part of the IESO's DER Roadmap
- This Roadmap provides an overview of all the IESO's DER-related projects and connects each project to three identified key focus areas for DER integration activities

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Next Steps: Implementation Pathways

- The IESO will continue making improvements to the non-wires options development during IRRPs, as needed
- A guide to NWA assessments in IRRPs will be posted in Q4 2022
- The IESO-OEB will host a joint webinar on the DER Roadmap in Q4 2022
- Upcoming work (2023+) will focus on exploring the procurement mechanisms and potential implementation pathways for NWAs along with those already under evaluation for energy efficiency

Non-Wires Regional Planning Process Improvements

- To refine the approach to identifying opportunities for cost-effective DER and energy efficiency to defer traditional transmission solutions

Non-Wires Options Development

- To develop NWAs in sufficient detail to assess their economic viability and operationalize IRRP recommendations

Procurement Mechanisms for NWAs

- To consider how to procure resources as part of implementing non-wires solutions (i.e., via Capacity Auction, Medium-Term/Long-Term RFPs, or define new approaches), where cost-effective

Feedback for Today’s Webinar

- The accuracy of hourly load forecasting for a local area is heavily dependent on the granularity and quality of data available. What other data or considerations should we include in hourly load profiling?
- Are there any other NWAs or opportunities that should be considered in the IRRP's options analysis? How can the options analysis methodology be improved?
  - Are there operational considerations that should be accounted for when assessing non-wires solution that relies on a dispatch component? For example, does the current storage sizing approach sufficiently account for how it could be operated in today's system? If not, what improvements would be needed?

Submitting Feedback

- Please use the feedback form found under the August 25, 2022 entry on the DER Roadmap webpage
- Send written feedback to engagement@ieso.ca by September 16, 2022

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