IESO Market Renewal Project

Input on Benefits Case Approach

PRESENTED TO

Independent Electricity System Operator
IESO Market Renewal Working Group

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THE Brattle GROUP

Agenda

- Overview
- Summary of Market Visioning Results
- Initial Thoughts on Benefits Framework
  - Energy Market Reforms
  - Operability Reforms
  - Capacity Market Reforms
  - Considerations for Existing Contracts
- Discussion
- Next Steps
- Appendix: Details and Study Review

Overview

- In today's meeting we will continue the discussion from the last session, developing the market renewal benefits case together with this working group
- We would like to discuss our initial thoughts on a framework for assessing the benefits of the proposed market reform initiatives.
- Objectives for today:
  - **Recap Market Visioning Effort.** Summarize findings and takeaways from the visioning workshop, and discuss with working group the best way to incorporate the futures into the benefits case and the ongoing Market Renewal effort
  - **Review Prior Analysis in Ontario.** For each major work stream (energy, flexibility, capacity), review findings from prior studies of the Ontario market and discuss implications for the benefits case
  - **Review Lessons Learned from Other Markets.** Discuss findings from other markets, and whether/how they apply to Ontario
  - **Obtain Your Input to Develop the Benefits Framework.** Develop a common understanding of the qualitative benefits case for the market renewal project and the framework and key assumptions that will be applied to quantify benefit ranges
- If we can accomplish these objectives in today's meeting, then we will present initial findings on benefits in late November/early December

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Recap of the Visioning Workshop Purpose

- The MRWG used scenario-based planning approach to assess how future system needs may affect the features of market design, including:
  - Discussing how to "stress test" the market design to make sure it is sufficiently flexible to support a range of plausible futures
  - Identify potential blind spots and opportunities prior to starting the design effort
- The backdrop considered include:
  - The Province's decarbonization goals, market forces, and policy preferences will shape the future of the electric system in Ontario
  - The IESO wants and needs to consider and manage future changes by considering the needed flexibility in the market design
  - Use the Ontario Planning Outlook as the starting point
- The MRWG achieved the following:
  - Identified key future drivers and risks to Ontario's wholesale market design
  - Developed a set of diverse "futures" (scenarios) and describe the range of functional requirements that may be needed to support these possible futures of the Ontario wholesale electricity market

Components of Market Renewal

- **Energy**
  - Single Schedule
  - Day Ahead Settlement
- **Operability**
  - Ancillary Services and Flexibility
  - Interties and Exchange with Neighbors
- **Capacity and Resource Adequacy**
  - Internal
  - Exports/imports

- **Environmental Attributes**
  - Tracking
  - Pricing and Effects on Dispatch

Major Drivers Developed by the Working Group

The MRWG identified key drivers that will affect each relevant future:

1. Future Electricity Usage and Load Growth

- National and provincial economic growth
- Traditional electricity load growth
- The use of electronics
- Electricity usage of data centers
- Electrification of transportation and heating

2. Demand-Side Resources

- Evolve to decentralized supply resources and smart girds
- Pace & magnitude of distributed generation deployment
- Need visibility to ensure reliability and resiliency when considering distributed generation
- Need to manage behind-the-meter activities
- Customers' preferences may be diverse
- Future (bigger) roles of distributors (potentially including Distribution System Operator)
- Potential for different flavors of retail access

3. Regulatory Framework for Electricity Sector

- Risks associated with the direction of future regulation
- Uncertain pace and magnitude of decarbonization
- Regulatory uncertainties limit market-based investments
- Need flexibility to react to future policies and reduce adverse impact of uncertainties and associated risks
- Regulated assets' effects on operations and dispatch

4. Contracts and Market

- Effects of market renewal on existing contracts, expirations, and new contracts (size and terms)
- Uncertainties around efficiency and flexibility to adapt
- Desire to optimize market and contract resources interactions
- Extent of market vs. contracts resources
- OEB process for (re)investments in certain generation resource as regulated assets

5. Fuel and Resource Mix

- Future of natural gas supply and pipeline infrastructure
- Future of gas and electric market interactions
- Cost and deployment of solar and wind resources
- Future of existing nuclear
- Reliability of supply if less reliance on gas resources
- "Capacity performance" if less reliant on "firm" resources

6. Other Drivers

- Risks to system resiliency such as outages
- Risks of stranded assets and costs, including gas pipelines and others
- Potential for a future East-West grid

Potential Futures Faced by Ontario's Electricity Market

The MRWG also explored four futures useful for developing the market renewal benefits case. They include:

Scenario	Summary Description
1. Current Trends	• Moderate changes relative to today's system • The environmental policies, such as decarbonization, are pursued in the province, with a trajectory of some additional renewable generation built, but not too aggressively • Slow electricity load growth, some electrification over the long-term but not sufficient to significantly alter the system's needs • Increasing-reliance on market-based and less on cost-based mechanisms
2. Deep Decarbonization	• Reduction of use of fossil fuels across various sectors, including: electricity, heating, transportation, industry • Much more GHG-free generation, particularly distributed resources • Storage becomes more economical and becomes a part of customers' distributed resources • A significant amount of customers able to sell back excess power from distributed generation
3. Highly Distributed and Decentralized Electricity Sector	• Greater emphasis on Local Distribution Companies (LDCs) and role as load servers and enablers • Customers as Prosumers, who consume and produce electricity; "Transactive" energy among customers • Role for distributed service platforms to manage distributed resources • Significant roles for energy managers in smart homes and communities • "Bragging rights" for customers who decarbonize • Storage becomes economical
4. Integrated Regional Markets	• Large well-coordinated market outside of Ontario (single market, but does not have to be) • The Northeast market would include ONT, QUE, MISO, PJM, NYISO etc... (NECC) • New Transmission may be desirable or needed to interconnect with neighboring systems • May be desirable to consider more aggregated system control across regions

Market Components Consistent Across All Four Futures

Emission Reduction from Power Sector

- Policy trend is clearly toward less emissions – only pace and magnitudes are uncertain

Electricity Usage

- Future demand depend on degree and pace of electrification of transportation and heating sectors (which in turn depend on public policies)

Distributed Resources

- Trend is increasing amounts of distributed resources, including small-scale renewable resources
- Power can flow to and from customers

Future Technological Breakthroughs

- Significant cost reductions in storage, smart grid and control technologies should be considered

Customers' Preferences

- Customers will want price and cost transparency
- Customers will want more control over consumption pattern and energy sources

Integration with External Markets

- Trend toward increased coordination and (potentially) integration among external markets
- Policies in external regions will create pressures on Ontario resources, system, and market

Market Visioning

Implications for Market Design

Current Trends

Potential new markets needed:

- Capacity Market
- New ancillary service products (e.g. ramp, fast responding reserve, regulation mileage)

Likely market features needed:

- Greater co-optimization among product markets
- Closer and deeper coordination with external markets

Deep Decarbonization

Potential new markets needed:

- Flexibility products to ensure system reliability

Likely market features needed:

- Visibility and ability to monitor changes in customers' preferences and investments over time
- Able to facilitate interactions with distributors or other distribution system manager
- Greater intertie capacity and capability to import and export power into and out of the province during periods of excess and shortage of generation
- Transparent and efficient pricing to help customers make the most efficient investment decision

Distributed/Decentralized System

Likely market features needed:

- Access to real time prices for customers
- More coordination between local distribution companies and the IESO (including prices)
- Locational prices (LMPs) to inform the value of resources
- Able to facilitate and enable central and decentralized resource participation
- All resources must be visible to IESO for efficient market dispatch
- Simple settlements, even in more complex system

Integrated External Regional Market

Likely market features needed:

- More explicit coordination with other neighboring regions (such as northeast coordinating council) for more than just reliability
- Use market to create incentives for resources needed (with less government intervention)
- Clear roles for markets while manage existing contracts

Implications for the Benefits Case and Market Renewal

- Focus on customer cost will continue and will likely intensify
  - Customer costs will in turn affect energy and environmental policies and customers' deployment of distributed resources
  - Thus, the "business case" for market renewal needs to be robust from the customers perspective
- Market can be the center for creating and supporting dispatch and investment efficiencies, but need a commitment from stakeholders and government
- Future market must account of uncertainties with flexibility to adapt
- Benefits of an "adaptable" market will increase as changes take place
- Many desired features of the future market are the same, regardless of the future that materializes
- This implies that a robust and flexible "Market Design 3.0" will yield the greatest benefits for Ontario

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Proposed Benefits Case Approach

- As discussed in prior meetings, we will qualitatively and quantitatively evaluate the Market Renewal benefits based on prior analysis of Ontario's market, lessons learned from other markets, and bottom-up analyses
- Existing contracts will have "two-way" interactions with market renewal:
  1. Implications of contracts for benefits of market renewal
  2. Impacts of market renewal on contracts
- We propose to address contract implications on MR benefits by:
  - First evaluating the potential benefits to the province in the long-term
  - Then estimating the achievable benefits considering the existing contracts
- We are looking for your input on:
  - Have we fully accounted for the full range of benefits and costs of market renewal?
  - How to best apply the lessons learned from other markets to Ontario?
- The appendix contains a more detailed summary of findings from other market studies and a bibliography of the referenced studies (also posted on the working group web page)

Implementation Costs: Approach

Benefits will be compared to IESO implementation costs, based on a bottom-up estimate from Utilicast:

Inputs

Analyze IESO estimates on staff and materials requirements for Market Renewal Project; leverage prior work and experiences in other markets to benchmark and identify best practices

Previous IESO Experience

Experience in Other Markets

- Uncertainties, risks
- Best practices and lessons learned
- Benchmarking

IESO Functional Scope

- Identify IESO's incremental market and non-market functions
- Define the scope of each function

Implementation Options

- Define timing of setup, "go live," and transitions to steady state
- Identify potential outside services

IESO Resource Needs

- Organizational requirements
- IT systems, facilities, equipment
- Capital vs. ongoing costs
- Perceived uncertainties and risks

Results

Summarize range of potential costs over time, and document primary drivers of costs and risks

IESO Start-Up Costs

IESO Operating Costs

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Approach to Evaluating Energy Benefits

We request stakeholder input on our initial thoughts for the following framework to evaluate the benefits of the proposed energy market initiatives

1 **Review prior studies of Ontario's system**
- Focus on SE-114 and SE-21
- Determine the scope of benefits considered in the study and consistency with the expected benefits of market renewal

2 **Supplement with studies of other RTOs' design enhancements**
- Consider the similarity and differences of the market characteristics and design changes

3 **Compile evidence across studies to develop an expected benefits range**

4 **Account for the implications of contracts** (see later slides)
- Determine the share of potential benefits likely captured prior to (vs. after) contracts expire
- Categorize contracts based on whether the asset owners are incentivized to operate based on market price and so can be expected to engage in more efficient behavior with more efficient prices

Drivers of Energy Market Benefits

Current Challenges in Ontario

- Market surveillance panel and others have expressed efficiency, incentives, and equity concerns with the two-schedule system
- Large out-of-market payments at $300+ million/year associated with settlements against HOEP but physical output based on constrained dispatch
- Contract structures introduce additional challenges, as certain resource types produce in all hours regardless of market price

Benefits of Market Design 2.0

Market Design 2.0: Day-ahead market, single-schedule, nodal pricing, A/S co-optimization, real-time unit commitment, constrained dispatch, three-part bids

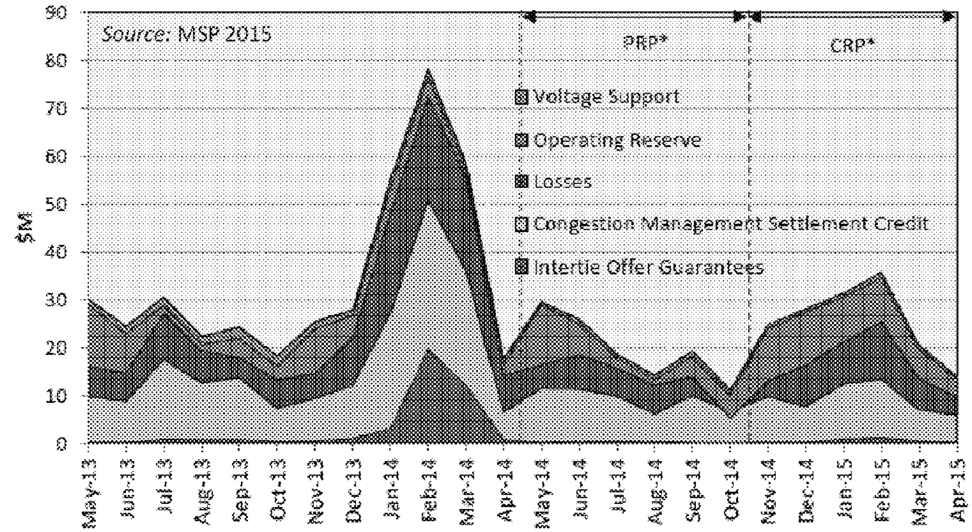
- Improved day-ahead and real-time commitment and dispatch
- Bringing out-of-market payments *into the price* will improve day-ahead and real-time commitment and dispatch and incentives for non-dispatchable resources
- Avoid unintended incentives and gaming opportunities
- Improved investment signals

Benefits of Market Design 3.0

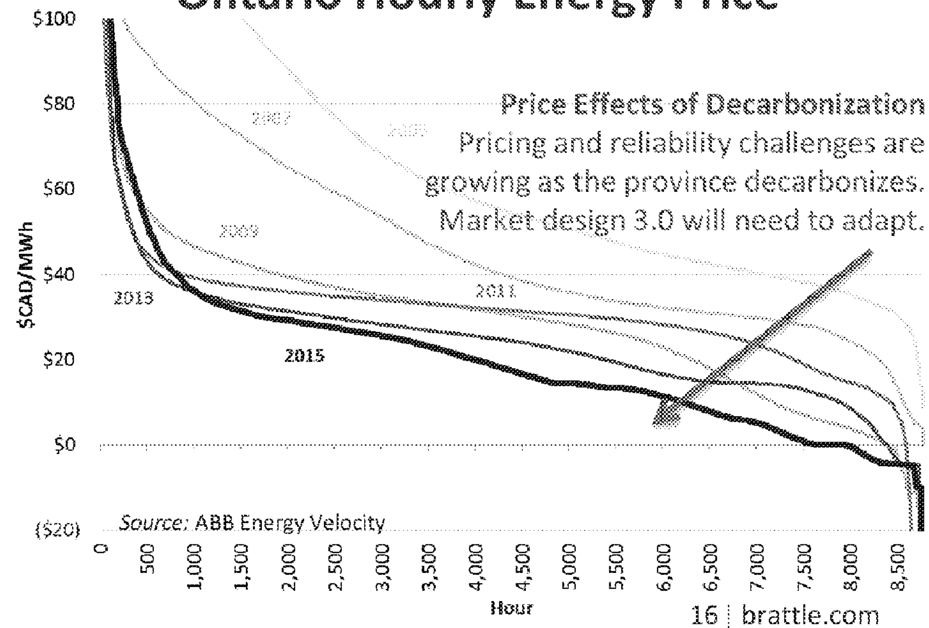
Market Design 3.0: Scarcity pricing, SBG pricing, demand response and distributed resource integration, optimized hydro/storage/interties

- Advanced commitment/dispatch(e.g. optimal hydro/storage, co-optimization, accounting for commitment costs in multi-interval costs in price-setting)
- Challenges will grow with decarbonization, greater flexibility needs, more intermittent resources, and increasing SBG events
- Will need to maximize use of resource fleet, including non-traditional resources and interties

Ontario Annual Uplift Payments



Ontario Hourly Energy Price



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Prior Ontario Analyses of the Proposed Energy Market Reform Initiatives

- Benefits case for energy market reform initiatives for Ontario is supported by a significant body of work from prior stakeholder engagements, Market Surveillance Panel studies, and other observer studies that will be included as qualitative considerations
- Quantitative estimates for Ontario are more limited, but two key studies are:
  - **Energy Market Pricing System Review** (SE-114, Market Reform 2015): Real-time LMP would introduce $10 MM/year in efficiency benefits, $160 MM/year in customer benefits before accounting for contracts ($40 MM/year after contracts)
  - **Day-Ahead Market Evolution** (SE-21, IESO 2008): Day-ahead market would save $24 MM/year in costs from over-commitment, DR dispatch, and gas procurement. A portion of the benefits have already been achieved through the enhanced day-ahead commitment process and three-part bidding
- Scope of these Ontario-specific studies was limited to examine only a portion of the efficiency benefits of energy market renewal. Thus, the majority of the expected efficiency benefits have not yet been quantified specifically for Ontario (see details in Appendix)

Notes:
Benefits translated to 2020 CAD$ assuming a 2% inflation rate (no other adjustments).

Assessing Applicability of Other Markets' Experience to Ontario's Unique Context

Stakeholders are keenly aware of the many differences between Ontario and other power markets. As a result, experience from other markets cannot be applied directly to Ontario.

In recognition of the unique Ontario context, we propose to apply experience from other markets by considering the following factors:

- Differences in the scope of market-design changes
  - Which design elements (e.g., nodal, zonal, day-ahead) were changed?
- Differences in market size, fuel mix, and other market conditions
  - Market size (annual load served)
  - The steepness of the supply curve (price duration curve)
  - The amount of variable renewable generation
  - Intertie capacities and flows
- Differences in the scope and quality of the benefits studies
  - Retrospective vs. prospective analyses (realized benefits of retroactive studies tend to be significantly larger than those estimated in prospective studies)
  - Extent to which all benefits have been quantified (most studies do not quantify all benefits)

Energy-Market Design Changes Studied

Design Element	MISO	CAISO	ERCOT	SPP
De-Pancaked Transmission Scheduling	2002 (Day 1, Bilateral)	existing	existing	2007 (Day 1, Nodal)
Real-Time Market	2005 (Day 2, Nodal)	existing (zonal)	existing (zonal)	2007 (Nodal)
Centralized Unit Commitment	2005	2009	2010	2014
Locational Marginal Pricing	2005	2009	2010	2007 (Real-Time)
Financially Binding Day-Ahead Market	2005	2009	2010	2014
Consolidated BA	2009	existing	existing	2014
Market-Based Ancillary Services	2009	existing	existing	2014
Co-optimization of Energy and Ancillary Services	2009	2009	2010 (Day-Ahead Only)	2014

In Place Prior to Market Redesign
Potential Element of IESO Market Renewal (Exact Elements Not Yet Proposed)
Element of Other RTO Redesign Studied (Shades Indicate Staged Implementation)
No Study Available

Benefits Case: Energy

Comparison of Market Characteristics

Question: How should we compare system characteristics between Ontario and other markets at the time of Market Design 2.0 enhancements?

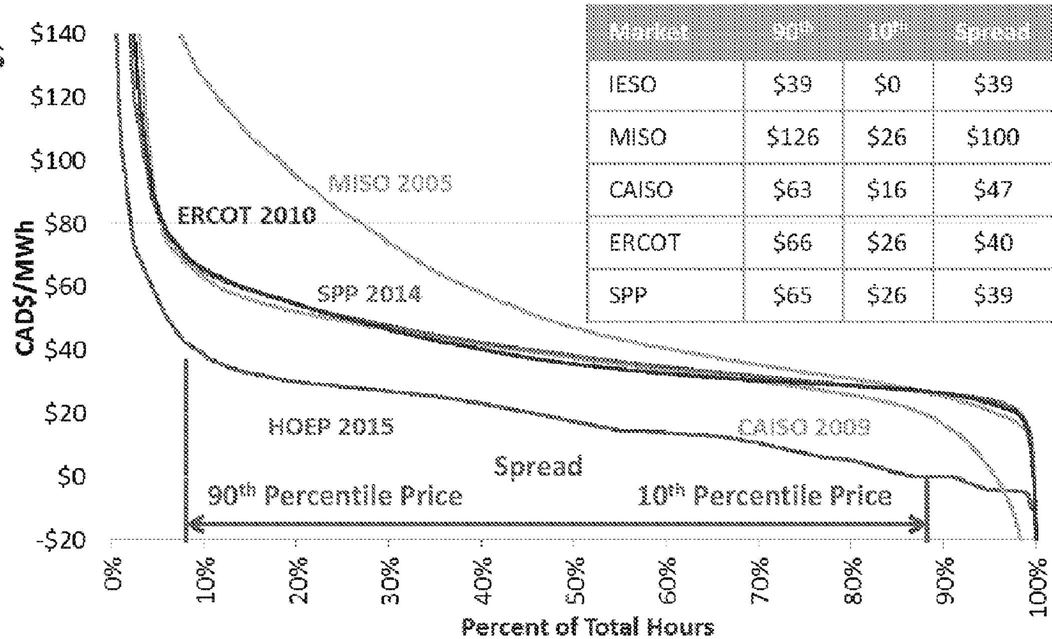
Diversity in Marginal Cost

- Energy market benefits depend on ability to adjust production to lower-cost resources
- <u>Benefits driven by the range in marginal costs across hours, including opportunity costs of hydro/interties</u>
- Price duration curve "spread" is one indication (potentially growing spread in a future where the tradeoffs are high-cost DR and no/low-cost non-emitting plants)
- Challenges: Ontario prices not always reflective of marginal costs (e.g. if resources are responding to contract incentives rather than market price)

Penetration of Intermittent Resources

- Flexibility <u>benefits dependent on degree of intermittent resource penetration</u>
- Many markets reformed with modest intermittent penetration, but some studies compare benefits in base and high intermittent scenarios
- Ontario's intermittent resources will continue to expand significantly in the coming years

Price Duration Curves at Nodal Implementation



Market	90th	10th	Spread
IESO	$39	$0	$39
MISO	$126	$26	$100
CAISO	$63	$16	$47
ERCOT	$66	$26	$40
SPP	$65	$26	$39

Intermittent Penetration by Market

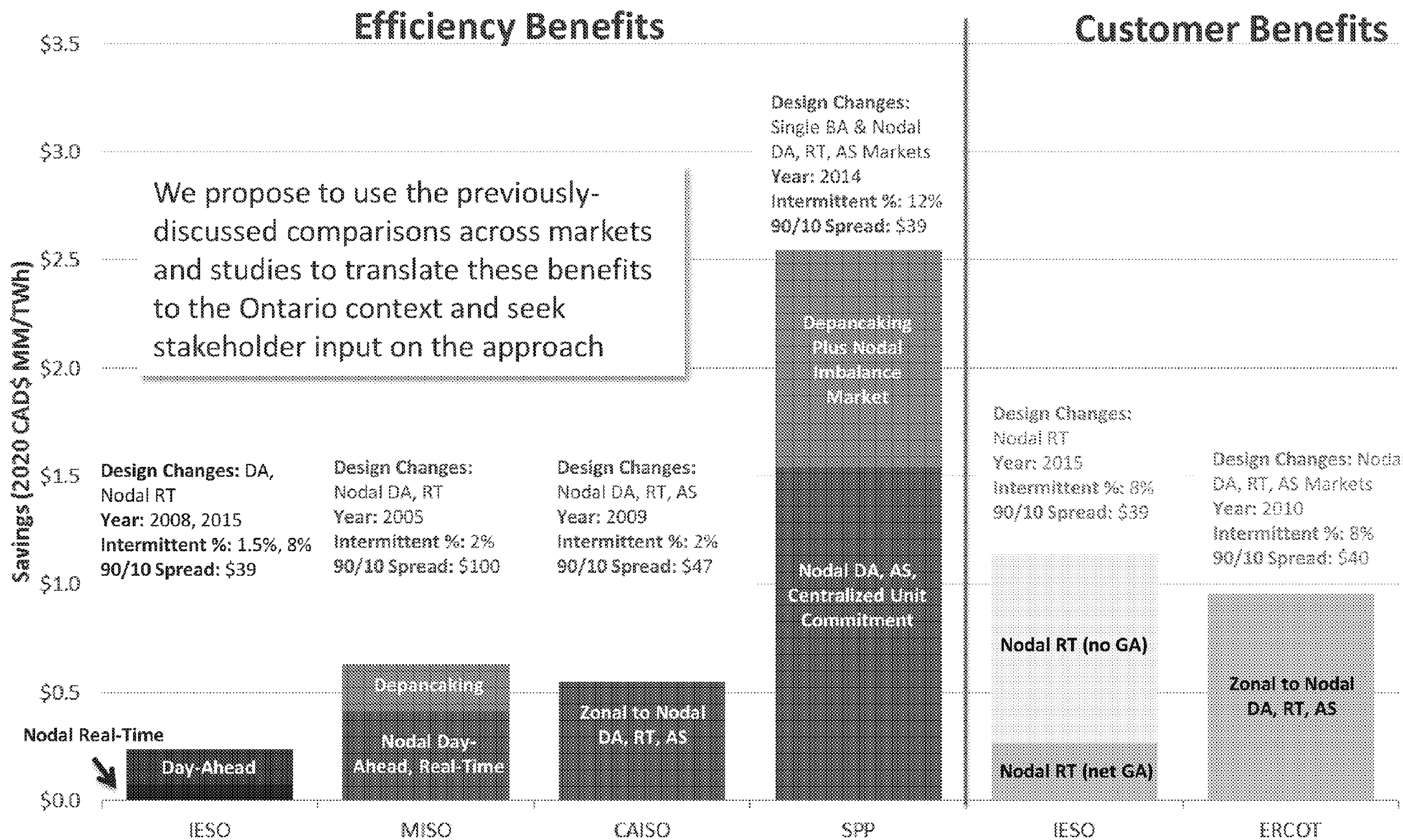
At the Time of Energy Market Reform

Market	Year	Intermittent Penetration (% of total generation)
IESO	2015 (2020s)	8% in 2015 (~12% by early 2020s)
MISO	2005	< 2%
CAISO	2009	2%
ERCOT	2010	8%
SPP	2014	12%

Ontario Characteristics
- Higher
- Similar
- Partial
- Not Similar

Benefits Case: Energy

Cross-Market Comparison of Energy Benefits



Sources and Notes (see Appendix for full citation):
All benefits translated to 2020 CAD$ assuming a 2% inflation rate (no other adjustments).
IESO: SE-21 (2008), SE-114 (2015); MISO: Reitzes (2009), CAISO: Wolak (2011), SPP: Rew (2015), ERCOT: Zarnikau (2014)

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Non-Quantified Benefits: Energy Market Renewal

We also identified expected benefits from the energy market renewal initiatives that we do not anticipate being able to quantify:

- Market Design 3.0 elements, such as incorporating multi-interval costs and commitment costs into price-setting
- Reduce uplift payment need, costs, and potential for inefficient bidding
- Reduce opportunities for gaming
- Advanced scarcity and SBG pricing
- Increase efficiency of locational investment incentives for traditional resources (including enhancements to existing resources)
- Increase efficiency of investment and dispatch signals for non-traditional resource types such as storage and demand response
- Larger potential efficiency gains than other markets if current commitment/dispatch is a less efficient starting point due to contract incentives

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Approach to Evaluating Operability Benefits

We request stakeholder input on our initial thoughts for the following framework to evaluate the benefits of the proposed operability initiatives

1. **Review prior studies of Ontario's system**
   - Energy/Ancillary Service Market Enhancements: Benefits not yet studied in Ontario
   - Intertie Enhancements: Focus on SE-115 (15-minute intertie scheduling)
2. **Supplement with studies of Other RTOs' design enhancements**
   - Consider the similarity of the market characteristics and design changes
3. **Compile evidence across studies to develop an expected benefits range**
4. **Account for the implications of contracts**

Drivers of Operability Benefits

- Ontario is increasingly facing challenges associated with system operability, due to greater proportion of intermittent resources, must-run generation, and high baseload generation conditions
- To decarbonize further, the visioning exercise anticipates that the market will need to maximize the market's capability to provide flexibility services, options include:
  - **Harnessing the flexible resource potential** of resources that have not historically provided these services to maximum potential (hydro, intertie, demand response, distributed resources)
  - Introducing **new operability products**, such as ancillary/ramping services or flexible resource requirements
  - Enhancing **intertie** exchange (reduce latency, increase scheduling interval, improve day-ahead, coordinated scheduling)
  - Other **operational enhancements**
- Many aspects of Market Design 3.0 will need to be geared toward achieving these operability benefits and enabling market evolution toward a distributed resource future

Benefits Case: Operability

Prior Analysis of Ontario Operability Initiatives

- Several types of operability enhancements have not yet been studied for IESO system, particularly from enhanced ancillary products and increasing benefits at high intermittent resource levels
- One study to evaluate enhancement from one type of intertie enhancement has been conducted:
  - **An Examination of More Frequent Intertie Scheduling** (SE-115, IESO 2013): Increasing to 15-minute and near real-time scheduling would achieve $11 MM/year in efficiency benefits
  - Scope did not include the potentially larger benefits of improved intertie scheduling day-ahead, scheduling based on intertie LMP, coordinated transaction scheduling, or depancaking
- In Ontario, the focus on operability has been driven by reliability needs and the full effect of benefits has not yet been quantified

Notes:
All benefits translated to 2020 CAD$ assuming a 2% inflation rate (no other adjustments).

Insights from Ancillary Service Redesign Efforts

- **Ancillary service innovations** are being pursued to meet future system flexibility needs, achieving benefits from:
  - **New products** that better reflect the changing needs for systems with high penetrations of intermittent resources
  - **Pricing innovations** that incentives fast response exactly when needed
  - **Enabling qualification** to provide these products from new technologies that have different technical characteristics
- **Benefits studies** are not usually done given that each change reflects modest costs, but two examples:
  - ERCOT Future of Ancillary Service study (2015) found $0.06 MM/TWh (CAD 2020$) from redesigning ancillary services to better match fast-ramping needs and enabling new technology types
  - MISO ramp product study (2013) found $0.02 MM/TWh benefits (2020$) from improved dispatch, avoided CT commitments, and avoided scarcity events
  - Both studies consider only a portion of benefits, for example not considering investment cost effects

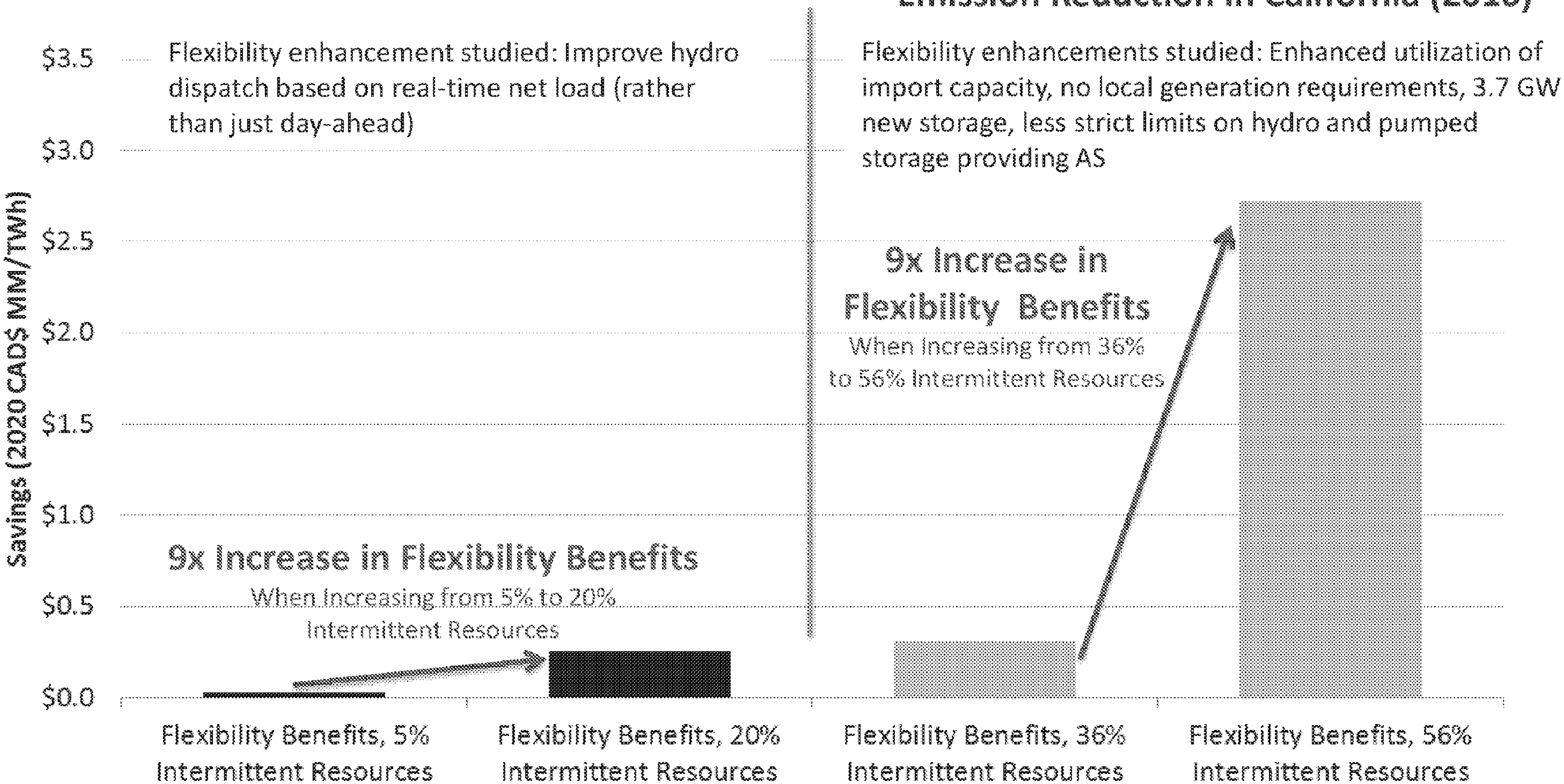
Ancillary Service Innovations	
Product Innovations	• MISO Dispatchable Intermittent Resources: Market-based mechanism for implementing intermittent resource curtailments for balancing • MISO and California Ramp Products: New ancillary service holds back resources based on outlook for ramping needs in future dispatch intervals • U.S. RTOs' Regulation "Mileage" Payment: Compensation for MWh up and down movement above cleared regulation • Decomposed Regulation Up and Regulation Down Products • ERCOT Future of Ancillary Service Design: Redefine ancillary service products to facilitate more efficient procurement based on resource capabilities
Pricing Innovations	• Real-time co-optimization of energy and ancillary services • Look-ahead security constrained economic dispatch • Operating reserve penalty factors • ERCOT Operating Reserve Demand Curve
Addressing Qualification Barriers	• Enabling storage was one driver of ERCOT FAS and FERC regulation mileage, recognizing increased value of fast-responding resources • Increasing caps on the proportion of demand response resources allowed to provide supply • Adjusting technical requirements to accommodate non-traditional resource types

Insights from High Intermittent Resource Studies

Benefits of all kinds of flexibility enhancements grow substantially as more intermittent resources enter the system

Pan-Canadian Wind Integration Study (2016)

Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California (2016)

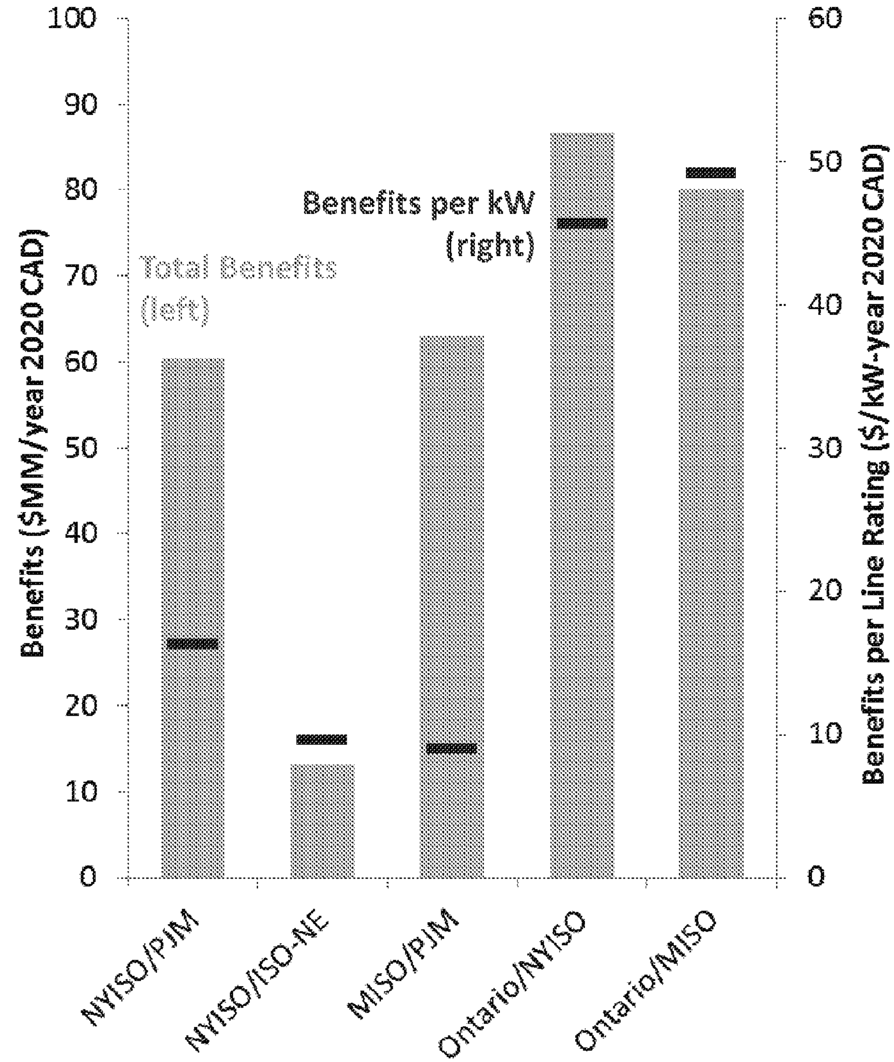


Benefits Case: Operability

Drivers of Intertie-Related Operability Benefits

- Root causes of economic inefficiencies:
  - **Transaction Costs:** Transmission charges and other fees reduce or eliminate market participants' incentives to flow power when it is otherwise economic
  - **Latency:** Time delay between scheduling and power flow, during which system conditions may change
  - **Frequency:** Intra-hour differences in economics
  - **Non-economic Clearing:** Limited coordination between markets causes uneconomic schedules to proceed
- Various attempts to maximize economic use of existing interties
  - **Coordinated Transaction Scheduling:** Increases information sharing and coordination between neighboring markets, with the objective of clearing tie schedule requests more economically (see Appendix)
  - **European Market Coupling:** Resources are dispatched across markets, subject to intertie capacity; however, coupling is only day-ahead (intraday starting Q3 2017)
  - **Western US Energy Imbalance Market:** Real-time economic re-dispatch of available resources across multiple markets at nodal level, automatically adjusting intertie schedules as needed

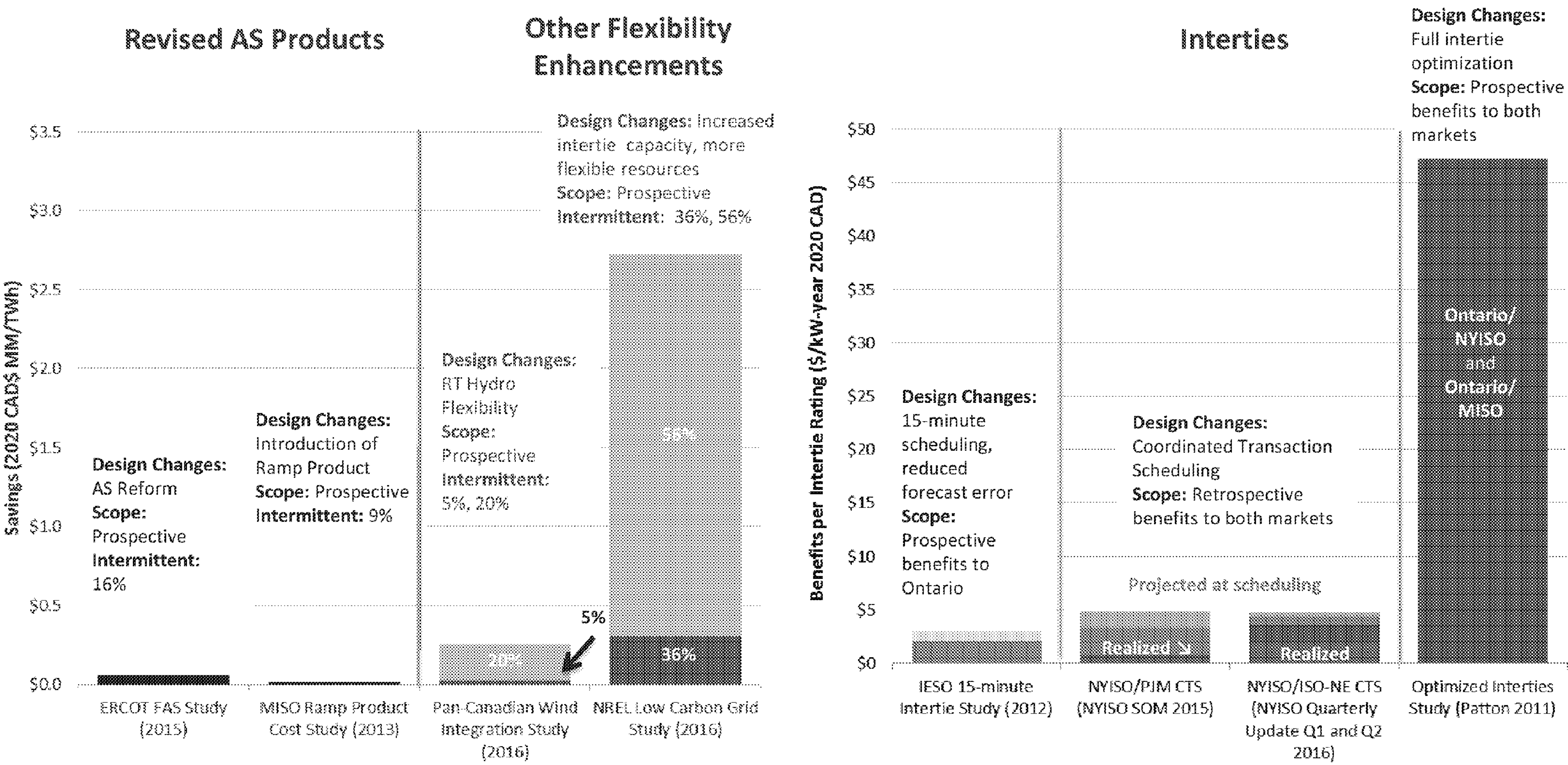
Benefits of Full Intertie Optimization From Patton (2010)



Source and Notes:
All benefits from Patton (2010) and translated to 2020 CAD$ assuming a 2% inflation rate.

Benefits Case: Operability

Cross-Study Comparison of Benefits



Notes:
All benefits translated to 2020 CAD$ assuming a 2% inflation rate.

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Non-Quantified Benefits: Operability

We also identified other expected benefits from operability initiatives that we do not anticipate being able to quantify:

- **Ancillary Services:**
  - Other types of A/S products
  - Benefits at higher wind penetration
  - Investment savings effects
  - Avoided curtailment (reducing CO_2 and/or additional investment)
  - Enabling non-traditional resources
- **Flexible Hydro:**
  - Additional types of flexibility needs outside of wind
  - Benefits of exposing hydro to market price incentives
- **Enhanced Intertie Scheduling:**
  - Benefits with non-market regions
  - Avoided CMSC and IOG payments, associated gaming and inefficiencies
- **Other Operability Benefits**
  - More flexible nuclear, storage, demand response, and distributed resources
  - Flexible resource requirements
  - Improved investment signals by resource type and location
  - Additional benefits from exposing resources to market rather than contract prices

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Approach to Evaluating Capacity Auction Benefits

We request stakeholder input on our initial thoughts for the following framework evaluate the benefits of the proposed capacity market initiatives

1 **Review prior studies and experience in Ontario**
- Focus on IESO staff's capacity market benefits study
- Examine outcome of transitioning DR auction from contracting to auction

2 **Supplement with studies and experience in other RTOs**
- Evaluate quantity of incremental low-cost supply attracted or retained
- Evaluate evidence of differences between contract and market prices
- Consider the similarity of the market characteristics and regulatory context

3 **Update IESO staff estimate of Capacity auction benefits**
- Update based on 2016 Ontario Planning Outlook assumptions and results
- Make explicit assumptions regarding low-cost incremental supply sources
- Separately estimate societal and customer benefits
- Develop a range of potential outcomes

Drivers of Capacity Auction Benefits

- Ontario is proposing to introduce capacity auctions as an additional tool for investment decisions
- A capacity auction would allow Ontario to achieve efficiency benefits, similar to those identified in other capacity markets, including:
  - Market competition attracting low-cost and non-traditional resources such as demand response, uprates, imports, and new generation
  - Achieve cost savings by enabling competition among resource types, and between new/existing supply
  - Capacity exchange will allow for increased revenue from exporting excess supply (option to import lower-cost supply when needed)
  - Ability to mitigate the quantity of over-procurement through short-term procurements and exports
  - Re-align risk allocation to the party that is best able to manage risks
- There are outstanding questions on how a capacity auction would interact with government policy and support future market evolution

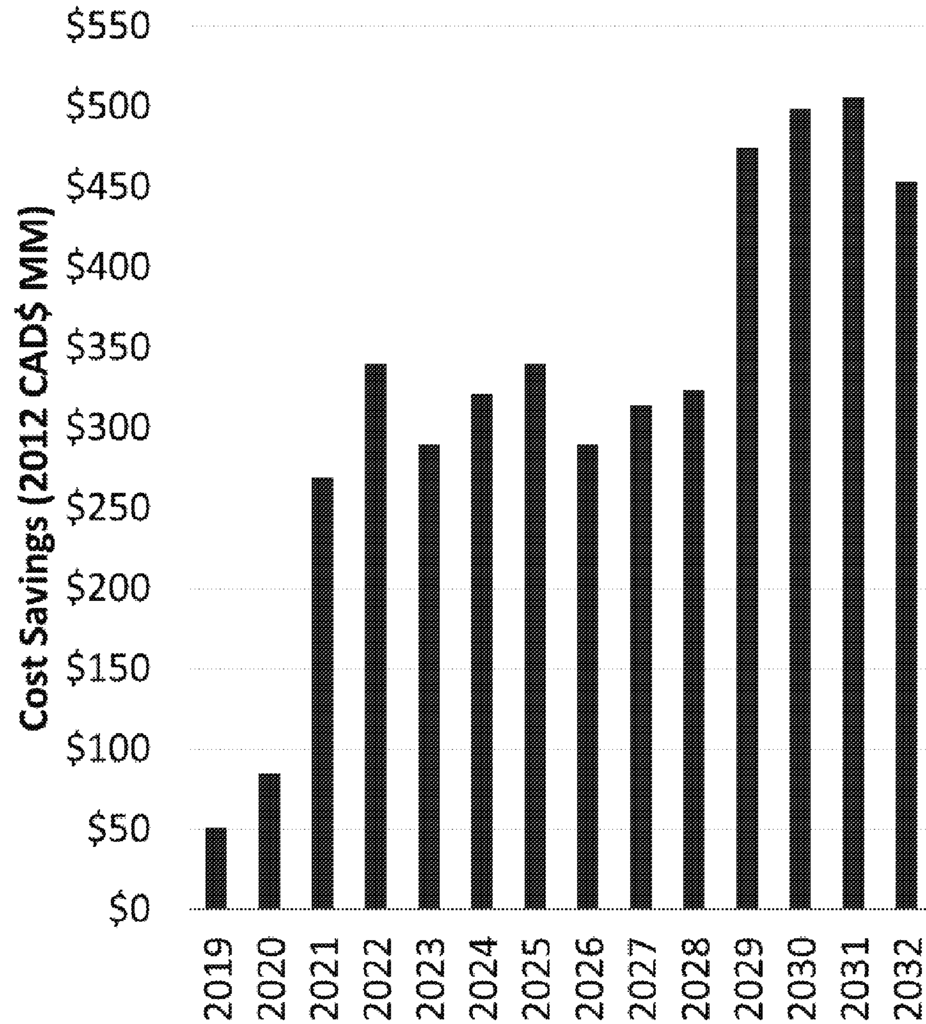
Benefits Case: Capacity

Prior Analysis of Ontario's Capacity Auction

2014 IESO Study of Benefits

- Compared the NYISO and PJM capacity market outcomes to the 2013 LTEP assumptions and estimated $50-500 MM/year in efficiency benefits
- Customer benefits not estimated
- Driven by lower expected procurement prices in a capacity market
- Assumed a $52/kW-year resource cost under capacity auction (based on NYISO and PJM market prices) versus $130/kW-year for additional capacity (based on the 2013 LTEP)

Estimated Cost Savings from Capacity Auction



Source and Notes: http://www.ieso.ca/Documents/consult/capacity-20140918-Assessment_of_Expected_Benefits.pdf

Experience from IESO Demand Response Auctions

The first demand response auction cleared at a lower price than the last standard offer program

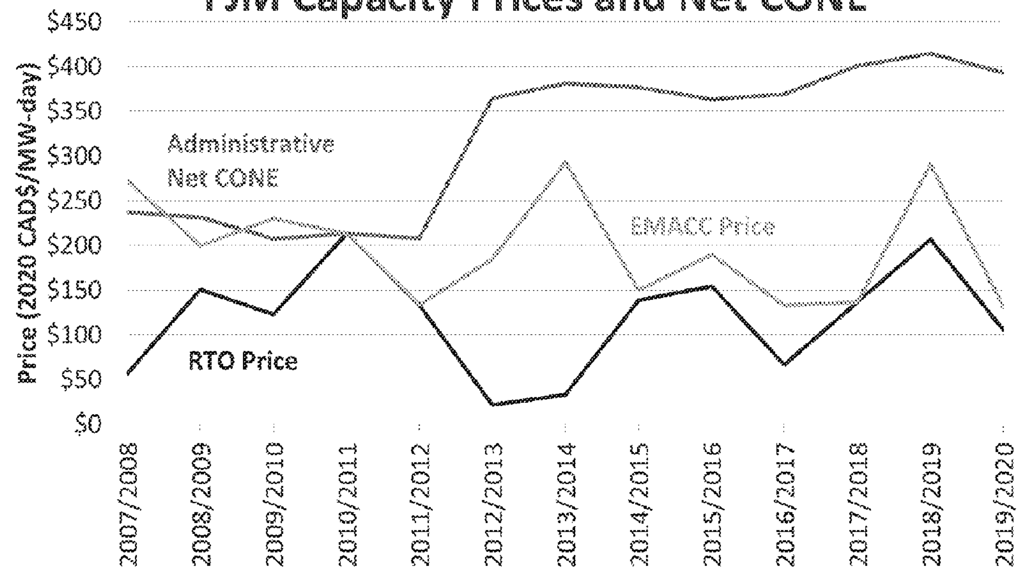
- Under the DR3 program the last standard offer price contract available made a capacity payment of approximately $104/kW-year
- Under the auction, IESO was able to procure more capacity than the target replacement quantity, at a lower price of $93/kW-year
- The DR auction also attracted more competition, increasing from 6 registered providers to 7 providers clearing in the DR auction.
  - 22 DR providers are now eligible to submit offers in the upcoming December 2016 auction
- Results of the next DR auction will be available in time to inform this benefits study

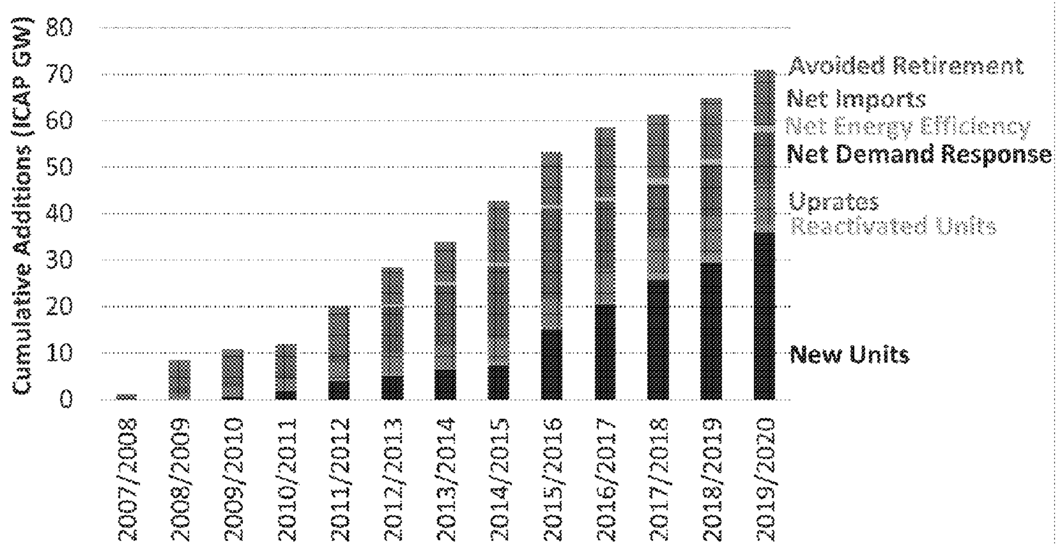
Notes: DR3 offer price was $65/MWh x 1,600 hrs/year of availability, or $104/kW-year. The DR Auction are converted from $/MW-day after multiplying by the number of business days of required availability.

Experience from PJM: Lower-Cost Resources

Many new resources have been added since the inception of the capacity market

- 32 GW of new gas capacity (in addition to uprates and demand response) have cleared at prices well below the administrative Net CONE
- 15% of the resource requirement 2019/20 capacity came from lower-cost non-traditional supply (excludes new units)
- 0.2-0.8% per year in lower-cost uprates to existing fleet are added each year
- 0.75% average annual increase in demand response and energy efficiency capacity
- DR reductions in 2016/17 and 2017/18 were driven in part by changes to the procurement rules which decreased the procurement of "summer-only" demand response



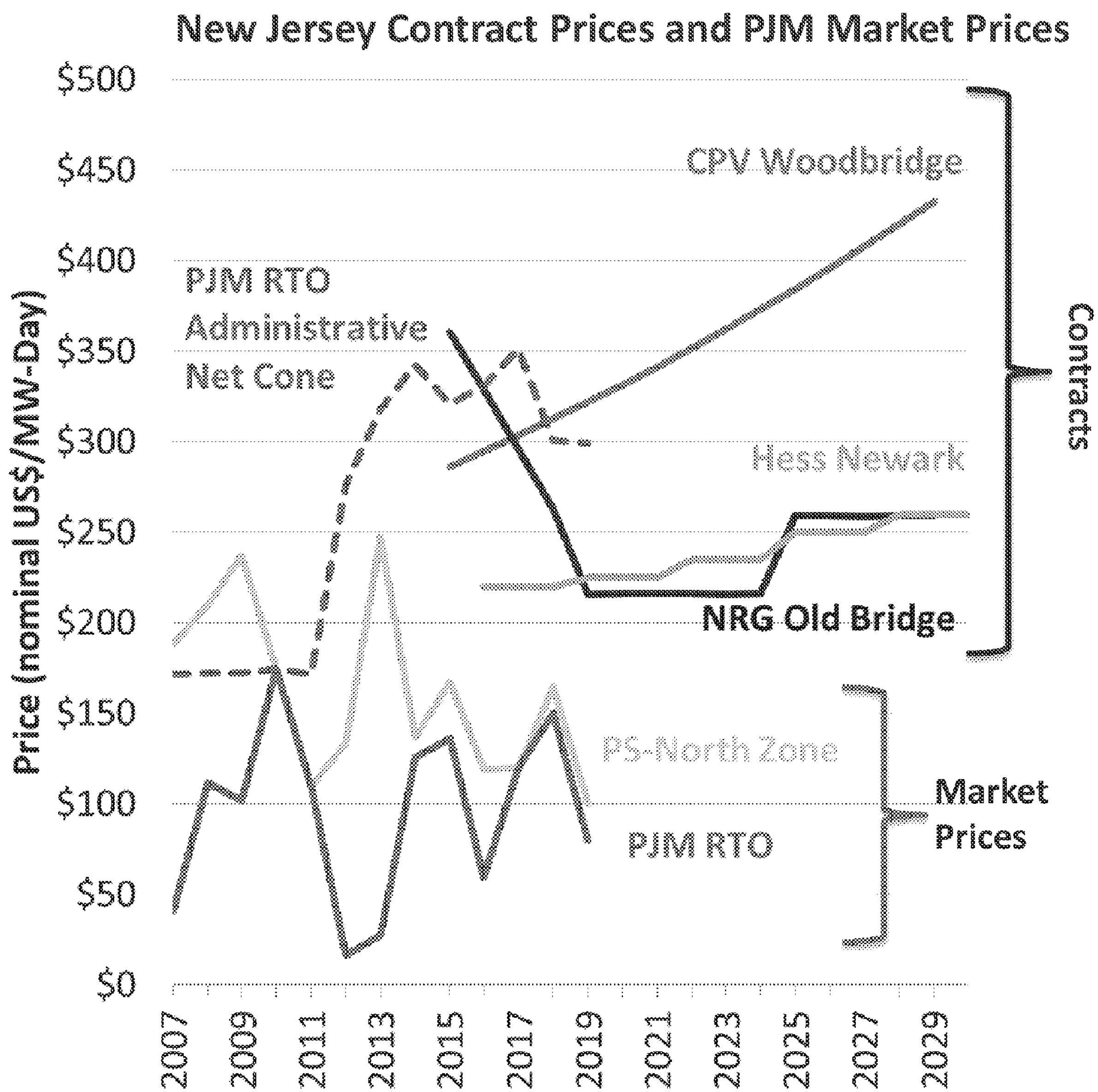


Source and Notes:
PJM 2019/20 Base Residual Auction Results. Prices assume a constant 2% inflation rate and the monthly exchange rate as published by the Bank of Canada for the month in which the auction results were published.
Net imports includes reductions in exports from the 2007/2008 auction.

Experience from PJM: New Generation at Lower Cost than Competitively-Procured Contracts

In 2011 New Jersey policy makers directed state utilities to sign long-term contracts with generators

- Contracts were selected through a competitive solicitation (all contracts were later canceled, but reflected the expectation of binding commitment at the time)
- Large quantities of market-based new generation entered (not under contract) over the same timeframe at prices only 59% to 87% of the contract prices (comparison on a levelized NPV basis)
- Cancelling the contracts and relying on capacity market entry resulted in total savings of US$63 million per year for the 2,126 MW of capacity



Source and Notes: PJM. Contracts were for delivery into PS- North zone.

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Non-Quantified Benefits: Capacity Market

We have also identified other expected benefits from the market renewal that we do not anticipate being able to quantify:

- Seasonal capacity products for imports/exports if IESO becomes winter peaking
- New technology types other than those that have entered in other capacity markets that may be able to supply capacity at a lower price
- Locational capacity value
- Flexible resource requirements

Agenda

- Overview
- Summary of Market Visioning Results
- Initial Thoughts on Benefits Framework
  - Energy Market Reforms
  - Operability Reforms
  - Capacity Market Reforms
  - **Considerations for Existing Contracts**
- Discussion
- Next Steps
- Appendix: Details and Study Review

Approach to Assessing the Impact of Contracts

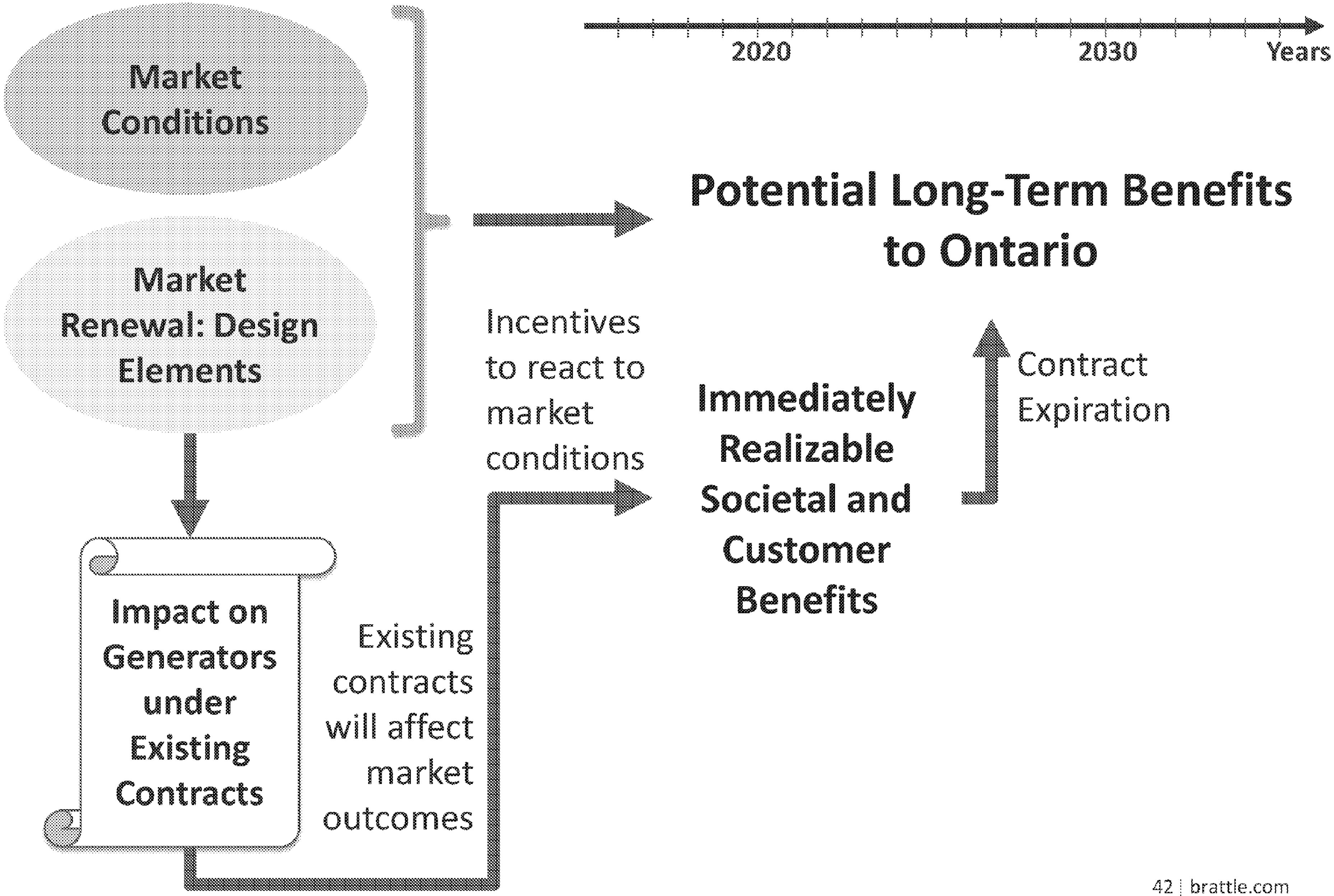
Based on feedback from the last meeting we would like to account more explicitly for the impacts of supply contracts in both the near term and the long term. We request stakeholder input on our initial thoughts on how do so:

1. **Evaluating potential long-term benefits to the province**

2. **Categorizing** existing contracts and regulated supply into high-level types , and evaluating for each type of contracts by asking:
   - What impacts will market renewal have on the existing contracts?
   - What impacts will the existing contracts have on the achievable benefits?

3. **Consider the timeframe** over which contracts will expire and understand the impacts on potential benefits:
   - Immediately achievable benefits independent of contractual arrangements
   - Total potential benefits that can be achieved as contracts expire

Evaluating Design Benefits and Contract Impacts

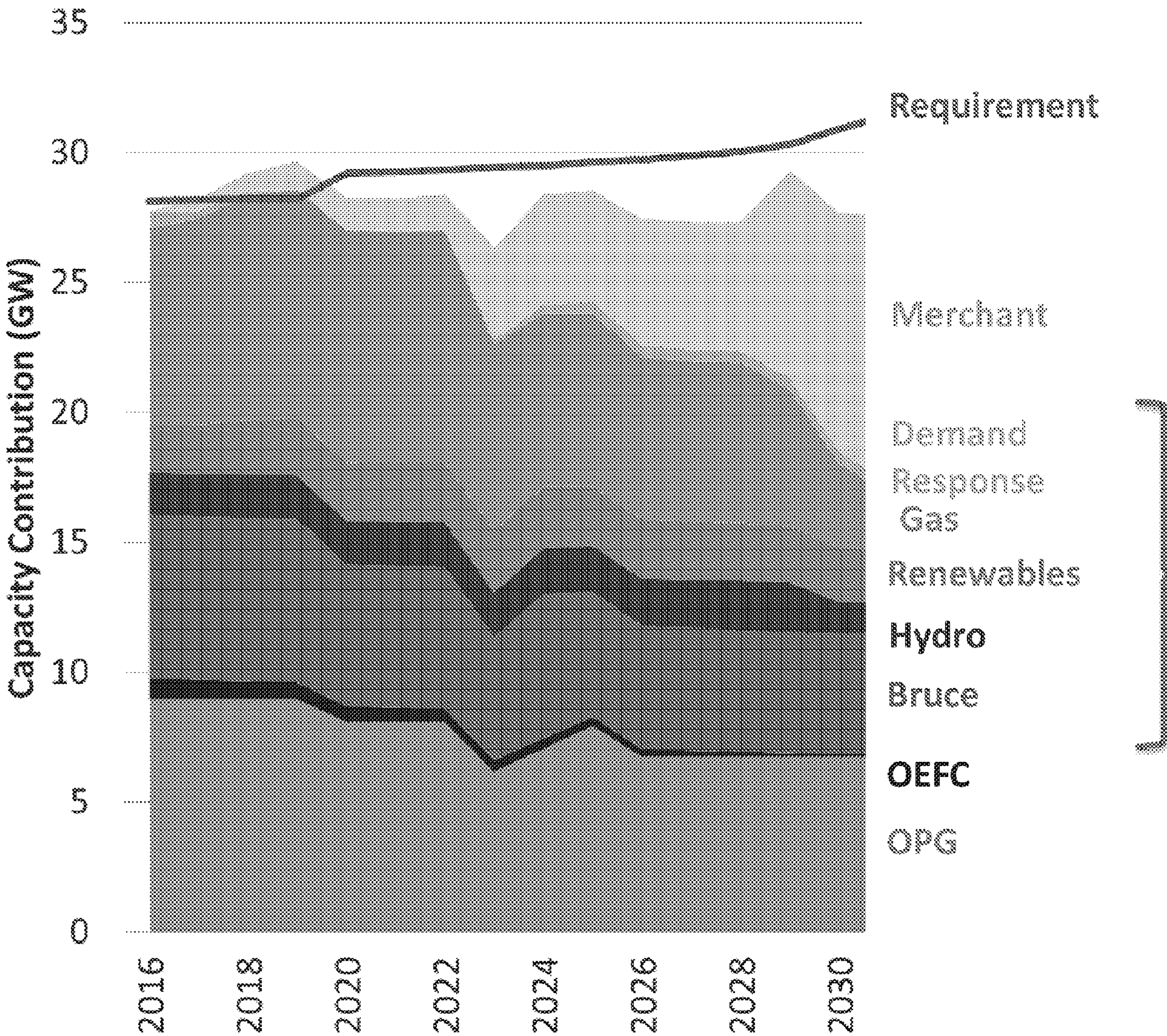


Discussion: How Will Market Renewal Affect Contracts?

- The current non-merchant resources can be broadly grouped into three categories
  1. Fixed Price Contracts
  2. "Deemed Dispatch" Contracts
  3. Regulated Resources
- We are currently reviewing each major category of contract and would benefit from stakeholder input on the following questions:
  - **What is the impact of the market renewal on contracts?**
  - **What is the impact of contracts on market renewal benefits?** Will suppliers have the incentive to adopt more efficient and flexible behavior in response to improved market pricing?

Benefits Case: Contracts

Contracts Exposed to E&AS Market Pricing Signals



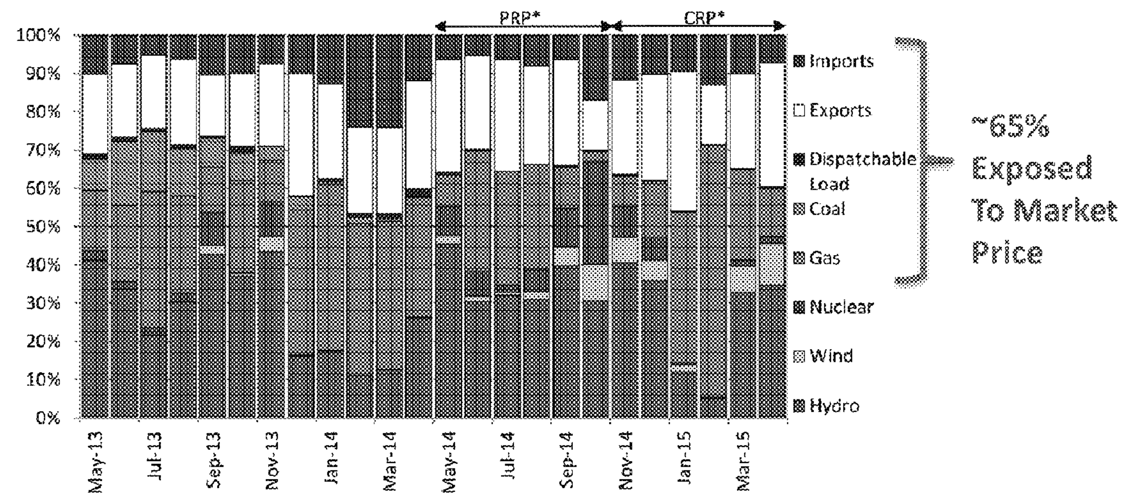
Category		Exposed E&AS Market Incentives?
Merchant • Existing non-contracted (e.g. nameplate in excess of contracted) • New resources • Uprates		Yes
IESO/ OPA	**DR**	Yes
	Gas • Lennox • CES • CHP	Mostly Yes
	Renewables • FIT • RES (I,II,III) • RESOP	Mostly No
	Hydro • HCI • HESA	Mostly No
	Bruce	Mostly No
	Other	Mostly No
OEFC		Mostly No
OPG	**Hydro**	Mostly No
	Nuclear	Mostly No

Source and Notes : These data are complied from several different sources and are slightly different from the 2016 Ontario Planning Outlook. Data from 2016 Ontario Planning Outlook, Outlook C and Q2 Progress Report on Contracted Electricity Supply.

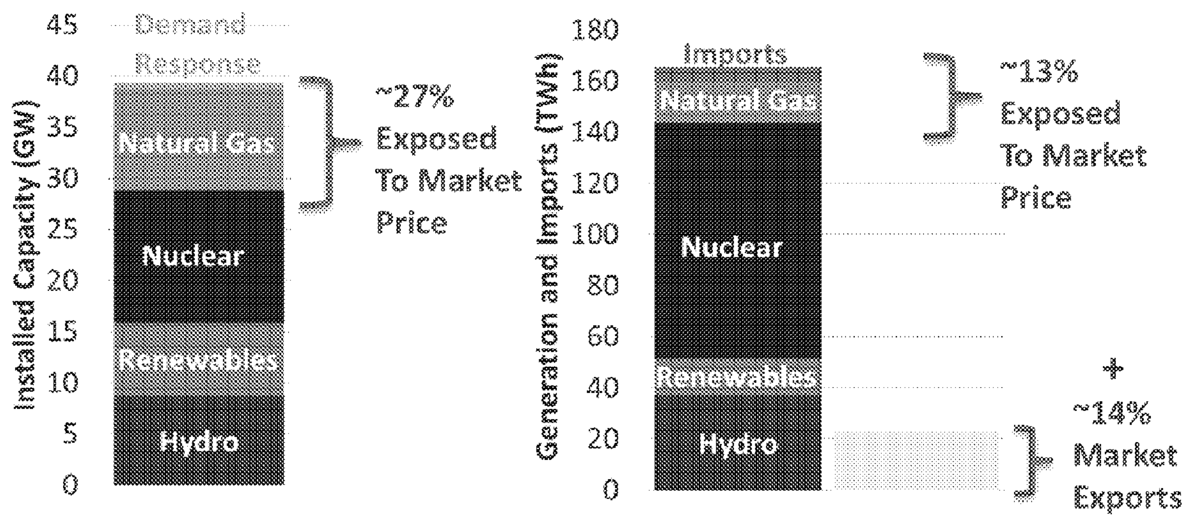
Achievable Benefits Depend on the Portion of Transactions Exposed to Market Incentives

- Energy and operability benefits achievable likely are proportional to the fraction of resources with dispatch exposed to market prices
- Consider:
  - **65% of resources on the margin** (on an hour-ahead basis) are operationally exposed to market prices (recommended metric)
  - 27% of installed capacity is operationally exposed to market price
  - 13%-27% of energy produced or exchanged is operationally exposed to market price
- Based on these data, 65% of the total potential benefits from energy market and operability initiatives would likely be realized even in the absence of contract expiration of modifications

One Hour Ahead Marginal Resource



2015 IESO Capacity and Generation



Upper Charts Source: Monitoring Report on the IESO-Administered Markets for the period from November 2014 - August 2015

Lower Charts Source and Notes: 2016 Ontario Planning Outlook. Includes embedded generation and exports .

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Discussion

We would like to get your thoughts and suggestions on our initial thoughts on how to estimate benefits of the proposed market reform initiatives

- Does the proposed benefit framework make sense and address the right issues?
  - Energy market
  - Operability (including intertie scheduling)
  - Capacity auction (including capacity exports/imports)
  - Implications of existing contracts
- What are your thoughts on the proposed approach for translating experience from other markets to the Ontario context?
- Other considerations and feedback?

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Next Steps

- Based on progress toward objectives and input received today, pursue next step of developing draft benefits case report
- Initial findings to be shared in stakeholder engagement meeting in late November/early December
- Draft benefits case to be published in Q1, 2017
- If group members wish to discuss any elements of this presentation in greater detail or provide feedback to be considered in the benefits case they are welcome to contact Brattle
  - Contact information on next slide

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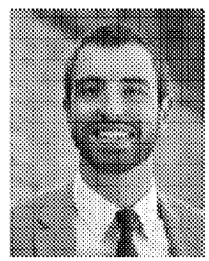

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Appendix: Details and Study Review

- Market Futures
- Study Review Detail
- Bibliography

Future 1: Current Trends

Load Growth
- Modest Net growth
- Load Shifting (flatter peaks over time)

Regulatory/Environmental Policy
- Modest Decarbonization policies
- Cost effectiveness is a consideration in setting environmental policies
- Policies generally increased reliance on market-based mechanisms
- Rate design and potential stranded costs will be considerations for policy makers

Distributed / Demand Resources
- Increase in demand response
- Smart Grid systems are further deployed across the province

Fuel and Resource Mix
- Nuclear refurbishment will take place as planned
- Increasing zero marginal cost resources
- Increasing firm imports
- Increasing frequency when gas generation is on the margin

Story
- Moderate changes relative to today's system
- Decarbonization continues in the province, but not aggressively
- Slow electricity load growth
- Increasingly goal to increase reliance on market-based and less on cost-based mechanisms

Implications for Ontario Market Design
- Capacity Market will likely be needed
- New ancillary products (ramp, regulation reactive power, etc.) may be needed
- Greater co-optimzation between Ontario markets
- May need to consider closer and deeper coordination with external markets

Contracts and Markets
- Expiring long-term contracts for energy, capacity, and clean energy resources
- The combination of contracts and market is set up to recover the fixed costs for:
  - Existing resources
  - New generation buildout

Resiliency and Flexibility
- Increasing need for load following resources

Other
- New technologies (such as storage) will need to be considered when they become desirable and/or cost effective

Future 2: Deep Carbonization

Load Growth

- Load growth (peak and shape) could be significant as part of heating and transportation sectors fuel switch to electricity

Regulatory/Environmental Policy

- Change in utility /customer relationship
- May need to consider changes to the way that load serving entities are compensated for complying with environmental policies

Distributed / Demand Resources

- More customers will have on-site generation
  - Micro –grids may become more ubiquitous
  - "Smart" load could sell power back to the system

Fuel and Resource Mix

- Significant increase in solar PV generation (both utility scale and distributed) and possibly distributed storage
- Much less natural gas and other fossil generation
- LRP return

Story

- Reduction of use of fossil fuels across various sectors, including:
  - Electricity
  - Heating
  - Transportation
- Much more distributed generation, particularly distributed renewable generation
- Storage becomes more economical and becomes a part of customers' distributed resources
- A significant amount of customers able to sell back excess power from distributed generation

Implications for Ontario Market Design

- Block Chain: some customers may decide to take on new technologies; thus need to monitor changes in customers' preferences and investments over time.
- Transactive Energy (at localized level) may mean that a significant effort may need to be placed on interactions with distributors or some other distribution system manager
- Need for flex products to ensure system reliability
- Need greater intertie capacity and capability to import and export power into and out of the province during periods of excess and shortage of generation
- Price information will become more important, particularly those that could help customer make the most efficient investment decisions

Contracts and Markets

- More customer on net metering and time-of-use programs
- Open access to transmission and distribution will likely be needed and allowed
- Bi-lateral contracts between customers and suppliers can be more prevalent

Resiliency and Flexibility

- Loss of diversity and therefore resiliency, particularly if a large part of the economy moves off natural gas and the use of gas infrastructure and onto electricity system
- Solely reliant on electricity could become more risky
- There could be an Increase in " local" resiliency if the customers' own systems and the distribution system are well managed

Other : Transmission/Distribution

- May result in reduced wire investments, particularly on the distribution systems
- There would be limits on how much more transmission can be built, particularly to the Toronto area (limitations include social and geography)

Future 3: Distributed Industry (Driven by New Technologies)

Resiliency / Flexibility

- Big Climate Change Disruption that causes more interest in decentralized energy resources

Economics

- Focus on cost increases (Cost curve ↓)
- The price of wholesale electricity increase (↑)
- New technologies become more affordable which allows customers to use more distributed generation
- Customers become more sensitive to price
- Customers reduce reliance on the grid

Deep Decarbonization

- Move away from natural gas fueled peaking plants
- Switch heating from natural gas to clean electricity
- Switch gasoline to electric vehicles
- More car sharing and autonomous cars

Nimby / Environmental Concerns

- Less interest in centralized generation
- Less interest in transmission and gas pipe lines thru "back yards"

Story

- Local Distribution Companies (LDCs) as load servers
- Customers as Prosumers, who consume and produce electricity
- Load Serving Entities (LSEs) also set up as distributed service platforms that manage the exchange of power on the distribution
- Transactive energy in both directions & among customers
- Customer as energy managers in the smart home
- Communities as energy managers
- "Bragging rights" for customers who decarbonize
- Risk of stranded utility assets
- Integration with grid will require additional investments and complex operations, which may lead to huge hidden cost
- Finally our industry will have inventory through the use of storage
- Regulatory dilemma → Arbitrage possibilities

Implications for Ontario Market Design

- Customers will want to access and see real time prices
- Much more need to coordinate between local distribution companies and the IESO (including price coordination)
- Need to simplify settlements, even in more complex system
- Heavy reliance on locational marginal prices (LMPs)
- Market must facilitate and enable DERs
- Software will be needed to enable central and decentralized participation
- All resources must be visible to IESO for efficient markets/dispatch

Technology

- More customers desire greener solutions across life of product
- Disruptive technologies may evolve
- Smaller and cheaper technologies will allow customers to control their energy consumption better and provide more choices

Fuel / Resource Mix

- Fuel switching in transportation from gasoline to electricity (clean)
- Heating fuel switch from natural gas to electricity (clean)
- Move the power industry from Big Generation to smaller distributed resources

Customer Empowerment (Load Growth)

- Customers emphasize desire for conservation
- Customer prefer to have real time monitoring and control
- Customers are also producers (Prosumers)
- Customers can transact among themselves (Transactive Energy)
- Customers increase their ownership of energy-related assets
- EV/ Fuel Switching

Contracts / Markets

- Contracts remain in the short-term as bridge to markets
- Use of cap and trade money will need to be resolved

Future 4: Well-Integrated Regions

Drivers

- Decarbonization in the U.S. makes Canadian hydro and storage more attractive for export
- Economic efficiency of coordination across the neighboring regions

Regulatory / Environmental Policy

- Governance of the energy sector needs to be more clarity(?)
- The development of policies and regulations should have a clearer path
- Alignment across policies will be needed(?)
- Need more clarity around dispute resolution(?)

Distributed / Demand Resources

- Load growth will be uncertain given the policy uncertainties
- Can capture load diversity
- Energy already integrated

Fuel and Resource Mix

- Storage capability will be shared by all
- Reliability across regions will increase
- Reliability at the local level may decrease (?)
- May increase the opportunity to decarbonize at lower costs
- More desire to optimize nuclear fleet
- More opportunities to optimize wind /solar/ peak hydro

Story

- Large well-coordinated market outside of Ontario (single market, but does not have to be)
- The Northeast market would include ONT, QUE, MISO, PJM, NYISO etc… (NECC)
- New Transmission may be desirable or needed to neighboring systems
- May be desirable to consider more aggregated system control across regions (control room? Smart grid enabled?)

Implications for Ontario Market Design

- Tracking jurisdictions by price, energy agencies and energy usage
- May need a more explicit coordination committee for better coordination and potential integration with other neighboring regions (such as NECC- such that it would not only be for reliability)
- Some stakeholders would prefer the market to take center-stage with less government intervention in the future (Pan – Juris)
- Need to evaluate options to manage the existing contracts

Contracts / Markets

- Likely to have more energy exchanges in the future when the external markets are well-coordinated
- Should evaluate Best Practices in other jurisdictions for managing contracts and markets simultaneously
- May need more common language / market rules with neighboring markets for simplicity

Resiliency/ Flexibility

- Will need improved system flexibility
- Will need the system to be able to integrate higher levels of renewables (with greater deployment)

Other (Barriers)

- Need northeast regional carbon market (NECC Carbon)
- Having a common carbon regime would simplify and improve coordination and ensure no leakage
- Other factors may include:
  - Government "independence"
  - Government ownership: Jobs, policy
  - Jurisdictional oversight: NAFTA, NERC, FERC?
  - Taxation? What, where, how?

Appendix: Details and Study Review

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- **Study Review Detail**
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Prior Analysis of Ontario's Energy Market Initiatives

Study	Scope	Benefits & Drivers	Benefits Not Quantified
Energy Market Pricing System Review SE-114 (Market Reform, 2015)	• Cost and benefits of single-schedule real-time pricing • Considers three design change scenarios, we focus on the "LMP Zonal" design (constrained DA & RT dispatch settled at LMPs, load settled at zonal LMP) • 14% intermittent resources by early 2020s	• **Customer Benefits:** \$160 MM/year customer benefits before accounting for contracts, driven by a reduction in payments to suppliers for energy and CMSC. Benefits drop to \$40 MM/year when considering contracts • **Efficiency Benefits:** Not calculated in most scenarios, estimated at \$10 MM/year in one scenario. Benefits driven by the twenty highest CMSC earning gas powered generators reducing their offer costs by 5% so as to increase their chance of being scheduled	• Improved efficiency from in-market signals (rather than uplift) for losses, ramping, ancillary co-optimization, transmission constraints, and interties • Avoided gaming and adverse commitment/dispatch incentives induced by uplift approaches (other than a modest adjustment for CMSC) • Improved real-time commitment/dispatch • Improved integration of new resource types • Improved investment incentives by location and resource type • **Overall**: Excludes most efficiency benefits
Day-Ahead Market Evolution SE-21 (IESO, 2008)	• Costs and benefits of improved Day-Ahead Commitment Process • Three redesign scenarios considered, we focus on Option 2 (24-hour optimized unit commitment, 3-part bids/offers, refined cost guarantees and an Energy Forward Market (EFM)) • ~1.5% intermittent	• **Efficiency Benefits:** \$5.5 MM/year for reduced over-commitment, \$16 MM/year for reduction in natural gas fuel procurement costs. Additional \$2 MM/year from DR due to improved day-ahead price forecast	• Improved day-ahead signaling and hedging for embedded and distributed resources • Improved intertie scheduling, and consequential improvement to in-province day-ahead dispatch • Increasing benefits at high intermittent resource levels • Other non-quantified benefits similar to above • **Overall**: Excludes most efficiency benefits

Notes:
All benefits translated to 2020 CAD\$ assuming a 2% inflation rate (no other adjustments).

MISO's 2005 Nodal Market Implementation

- Prior design was purely bilateral
- MISO region moved to an integrated marketplace in two stages:
  - First stage was to introduced de-pancaked "day-one" market (no central dispatch)
  - Second stage was a day-ahead market
- Ancillary services remained cost-based provided by each balancing authority (BA), not co-optimized with energy until 2009
- Retrospective study (Reitzes 2009) finds $0.41 MM/TWh (2020 CAD$) reduction in production costs due to 2005 design enhancements
- 2005 SOM also reported additional benefits such as reduced need to rely on transmission line loading relief (TLR) curtailments of wholesale transactions, which decreased by 75% from 2004 to 2005

System Characteristics

- $100/MWh price spread ✓
- 2% intermittent renewables ✚
- 2005 peak load: 112 GW
- High proportion of coal and natural gas in supply mix
- Diversity of load and resources across large geographic footprint ✓

Ontario Characteristics

- ✚ Higher
- ✓ Similar
- ✓ Partial
- ✖ Not Similar

Prior Design	Design Enhancement
Bilateral market	Centralized dispatch ✓
Depancaked transmission charges	Locational marginal pricing ✓
Single transmission operator	Financially-binding day-ahead market ✓
Cost-based ancillary services	5-minute dispatch ✓
	Cost-based ancillary services, no co-optimization or central dispatch ✚

Benefits Study

- Retrospective ✓
- $0.63 MM/TWh (2020 CAD$) total ✓
- $0.21 MM/TWh (2020 CAD$) from depancaked "day-one" market ✖
- Plus $0.41 MM/TWh (2020 CAD$) from implementing the day-ahead market ✓

CAISO's 2009 Nodal Market Implementation

- Prior market design created inefficiencies with intra-zonal congestion management
  - Units were self-committed on DA basis but then needed to be DEC-ed at high costs (with concerns about incentives for inefficient DEC bids)
  - Other units needed to be INC-ed at high costs
- Design enhancements made intra-zonal congestion management much more effective through optimal day-ahead unit commitment and settlement
- Retrospective study (Wolak 2011) finds $0.55 MM/TWh (2020 CAD$) reduction in production costs per TWh of load served due to design enhancements
- 2009 CAISO Annual Report showed AS procurement (i.e. customer) costs fell from 1.4% of wholesale energy costs ($0.74/MWh) in 2008 (prior design) to 1% ($0.39/MWh) in 2009 (design enhancement)

System Characteristics

- $47/MWh price spread ✓
- 2% intermittent renewables ✚
- 2009 peak load: 46 GW
- High proportion of imports, hydro, and gas (little or no coal) ✓
- Few or no min generation concerns ✚
- Substantial uplift charges from intra-zonal congestion management ✓

Ontario Characteristics

✚ Higher
✓ Similar
✓ Partial
✖ Not Similar

Prior Design	Design Enhancement
Day-ahead self-scheduling	Locational marginal pricing ✓
Zonal market (3 zones)	Financially binding day-ahead market ✓
Bilateral day-ahead scheduling	Hour-ahead scheduling ✓
Real-time imbalance market	5-minute dispatch ✓
Intrazonal congestion management process	Co-optimization of ancillary services ✓

Benefits Study

- Retrospective ✓
- $0.55 MM/TWh (2020 CAD$) ✓
- Production cost savings (fuel + VOM + start-up costs) for natural gas units
- Natural gas units represent largest source of energy internal to CAISO

ERCOT's 2010 Nodal Market Implementation

- Prior market design included depancaked transmission and footprint-wide network service
- Issues with intra-zonal congestion management
  - Zonal congestion management instructions were bid-based, because all generators located within in a zone were assumed to have the same ability to affect the flows across a zonal constraint (led to inefficiency and uncertainty)
  - All other constraints were managed by paying generators to either increase or decrease their output
  - Because congestion payments to generators were collected from loads, generators had no incentive to consider the state of the transmission system when scheduling
- 2011 market monitor report notes several aspects of nodal market design enhancement improve economic and reliable utilization of scarce transmission resources
  - Unit-specific offers and shift factors
  - Simultaneous resolution of all transmission congestion
  - Settlement of actual output instead of schedule-based dispatch
  - 5-minute instead of 15-minute dispatch

System Characteristics	Ontario
$40/MWh price spread	Similar
8% intermittent renewables	Higher
2010 peak load: 66 GW	
High proportion coal and natural gas in supply mix	
Electrical island connected with a few DC ties	

Ontario Characteristics
- Higher
- Similar
- Partial
- Not Similar

Prior Design	Design Enhancement	Ontario
Zonal market (4-5 zones)	Locational marginal pricing (4,000 nodes)	Similar
Bilateral day-ahead scheduling	Financially binding day-ahead market	Similar
Real-time imbalance market	5 minute dispatch	Similar
Intrazonal congestion management process	Co-optimization of ancillary services (DA only)	Similar
15 minute dispatch		

Benefits Study	Ontario
Retrospective	Similar
$0.95 MM/TWh (2020 CAD$)	Similar
Customer benefits (reduction in wholesale power prices)	

SPP's 2014 Nodal Market Implementation

- SPP implemented nodal market in two stages:
  - Energy Imbalance Service (EIS) was implemented in 2007, including real-time nodal imbalance service with depancaking
  - Integrated Marketplace was implemented in 2014, including fully integrated day-ahead and day-of and (central dispatch in only real-time after bilateral markets close markets)
- 2014 state of the market report describes benefits derived from:
  - Large reduction in the quantity of online generating capacity (10% reduction), due to coordinated day-ahead commitment
  - Co-optimization of energy and ancillary services
  - Non-quantified benefits from improved locational investment/retirement incentives

System Characteristics

- $39/MWh price spread ✔
- 12% intermittent renewables ✔
- 2014 peak load: 45 GW
- High proportion of coal and natural gas in supply mix (historical net exporter) ✖
- Diversity of load and resources over large geographic area ✔ (Partial)

Ontario Characteristics

- ✚ Higher
- ✔ Similar
- ✔ Partial
- ✖ Not Similar

Prior Design	Design Enhancement
• Depancaked transmission charges • Day-ahead self-schedule and commitment • Self-schedule AS • Nodal real-time imbalance market • 5-minute dispatch	• Consolidated balancing areas ✖ • Financially binding day-ahead market ✔ • Co-optimization of ancillary services ✔ • Day-ahead unit commitment ✔

Benefits Study

- Retrospective ✔
- $2.55 MM/TWh (2020 CAD$) ✔
- $1.01 MM/TWh (2020 CAD$) from EIS, including a de-pancaked regional nodal imbalance market ✔
- $1.54 MM/TWh (2020 CAD$) from integrated marketplace, including consolidating balancing areas, and implementing nodal DA, RT, and AS markets ✔
- Non-quantified benefits from start costs, optimization features, and improved investment incentives ✚

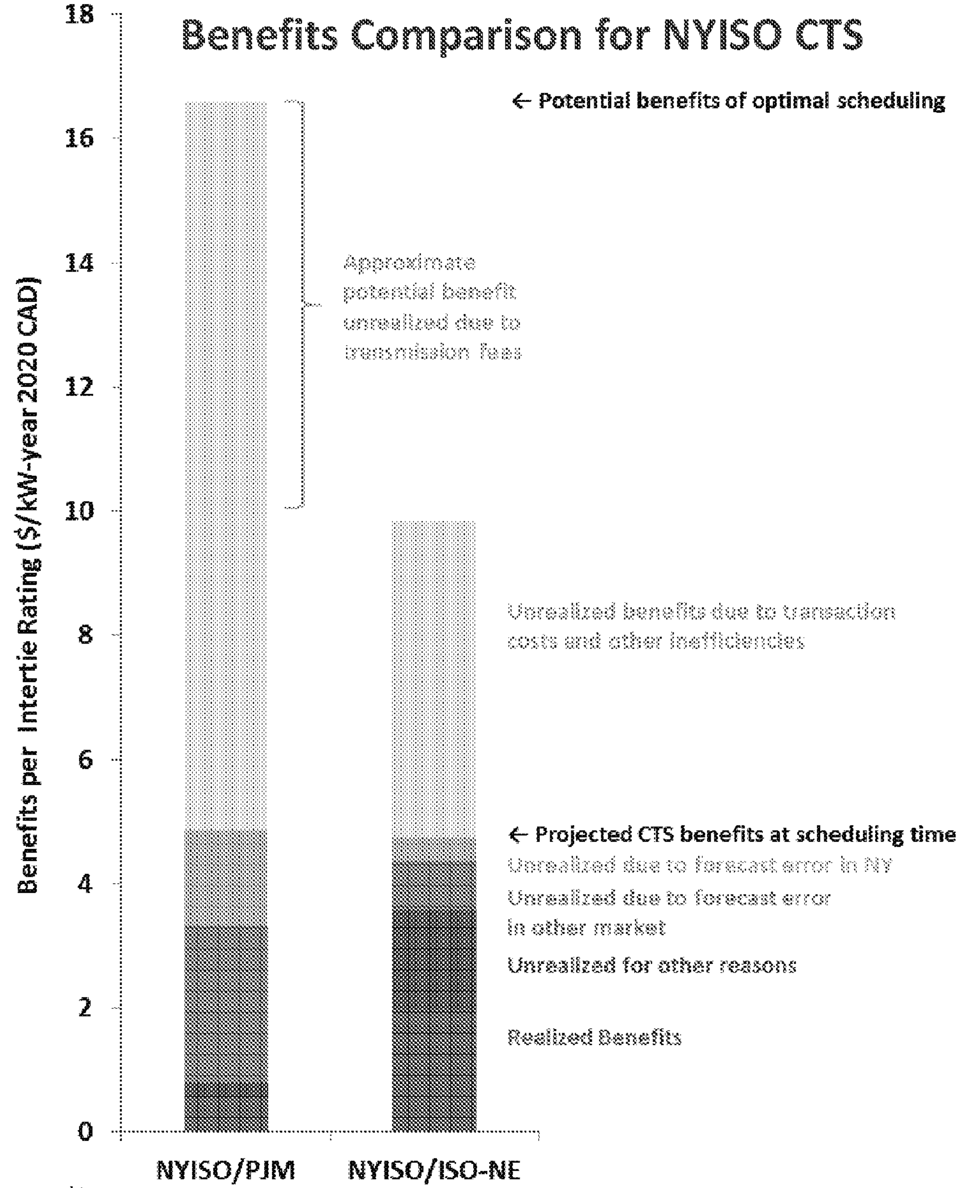
Prior Analysis of Ontario Operability Initiatives

Study	Scope	Benefits & Drivers	Benefits Not Quantified
An Examination of More Frequent Intertie Scheduling SE-115 (IESO, 2013)	• Benefits of reducing inefficient intertie transactions by determining intertie schedules every 15 minutes instead of hourly in 2012 and 2013 • Does not quantify benefits of updating scheduling algorithm data inputs more frequently or of increasing flows of efficient intertie transactions • Simplified method of accounting using reference bus price instead of nodal price at intertie as replacement cost of electricity	• **Efficiency Benefits:** \$1.8–\$3.8 MM/year in benefits of reducing inefficient transactions, driven by increased opportunity to terminate uneconomic transactions before end-of-hour. \$3.9–\$7.1 MM/year additional potential benefits of reducing forecast error inefficiency by scheduling at or close to real-time • **Customer Benefits:** Not estimated	• Using nodal pricing (rather than HOEP) pricing incentive at intertie • Avoided gaming and efficiency effects from uplifts (CMSC and IOG), and avoided customer costs • Coordinated transaction scheduling • Full intertie optimization • Reducing transmission charges • **Overall**: Excludes most potential benefits

Notes:
All benefits translated to 2020 CAD\$ assuming a 2% inflation rate (no other adjustments).

NYISO Coordinated Transaction Scheduling

- NYISO implemented CTS with PJM in November 2014 and with ISO-NE in December 2015
- CTS designed to maximize efficient intertie use by:
  - Making forecasted prices more transparent
  - Improving coordination of intertie scheduling between neighboring market areas
  - Allowing market participants to schedule flows based on projected price differences
- Realized benefits show significant disparity between PJM and ISO-NE
  - In CTS with PJM, relatively low benefits realized, primarily due to low use of CTS bids, as transmission service charges and uplift fees were not eliminated
  - Much higher quantity of low-price bids in CTS with ISO-NE, as fees were eliminated, incentivizing market participants to arbitrage even small price differences; significantly larger benefits realized as a proportion of possible benefits under optimal intertie scheduling
  - Remaining unrealized benefits due to latency delay-related forecast errors, real-time curtailment, interface ramping, and price curve approximation (NY/NE only, where supply curve is approximated by step function in CTS process)



Sources and Notes:
Benefits from Patton (2010), NYISO SOM (2015), NYISO Quarterly Reports (2016) translated to 2020 CAD$ assuming a 2% inflation rate.

Appendix: Details and Study Review

- Market Futures
- Study Review Detail
- **Bibliography**

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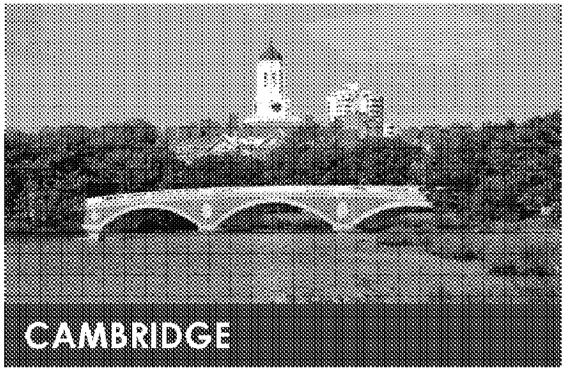
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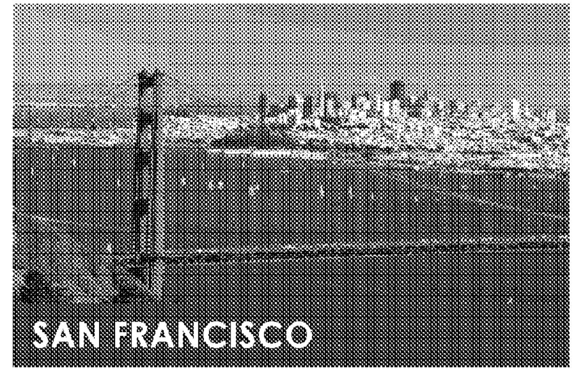
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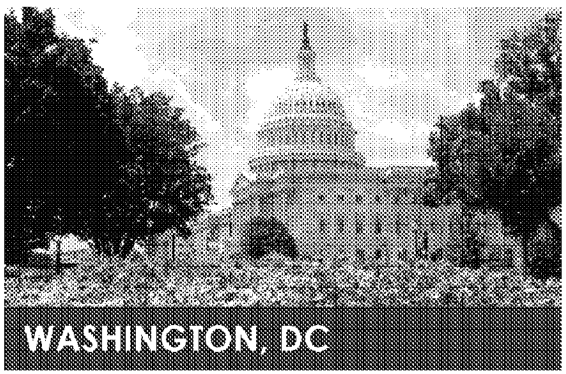
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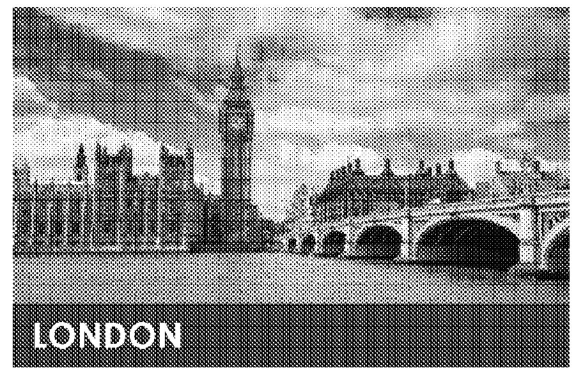
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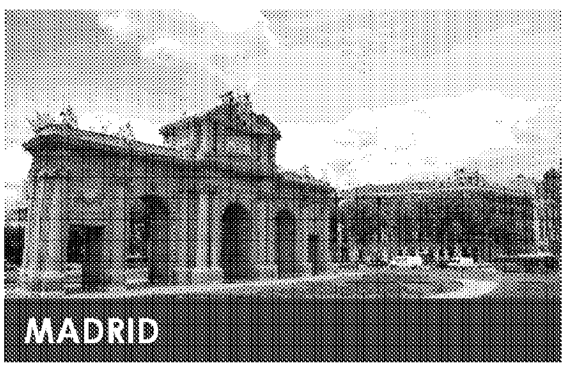
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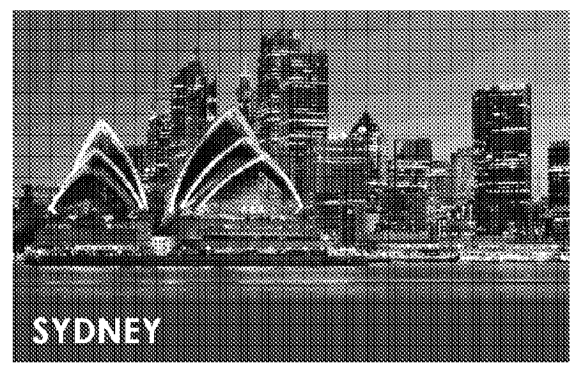
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