Power Advisory LLC

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December 1, 2020

Dear Shawn,

This submission responds to the entirety of the Independent Electricity System Operator (IESO) draft Market Renewal Program (MRP) detailed design documents that define planned and proposed changes to the wholesale energy and ancillary service markets within the IESO-Administered Markets (IAM).

Power Advisory LLC has coordinated this submission on behalf of a consortium of renewable generators, energy storage providers, and industry associations (i.e., the "Consortium"[1]). This submission builds upon the Consortium's previous submissions, now that we have reviewed all draft MRP detailed design documents, including review of IESO feedback on market participant (MP) and stakeholder submissions commenting on the draft MRP detailed design documents.

The following key areas are addressed within subsequent sub-sections within this submission:

- MRP design components;
- Additional stakeholder engagement meetings;
- Governance, decision-making, and recourse within IAM; and,
- Contract amendments related to MRP implementation.

The Consortium continues to support the MRP initiative, and appreciates IESO's invitation to provide additional comments on all aspects of the MRP draft detailed design.

MRP DESIGN COMPONENTS

The Consortium offers additional comments regarding the following four key areas within the draft MRP detailed design.

[1] The members of the Consortium are: Canadian Renewable Energy Association; Axium Infrastructure; BluEarth Renewables; Boralex; Capstone Infrastructure; Cordelio Power; EDF Renewables; EDP Renewables; Enbridge; ENGIE; Evolugen (by Brookfield Renewable); H2O Power; Kruger Energy; Liberty Power; Longyuan; NextEra Energy Canada; Pattern Energy; Suncor; and wpd Canada.

[redacted]

Ontario Specific Detailed Design Features

As specified within the Consortium's submission commenting on the draft *Pre-Dispatch Calculation Engine Detailed Design Issue 1.0*, the Consortium notes that no other wholesale electricity market in Canada or the U.S. applies such a Look-Ahead Period (LAP) within pre-dispatch (PD) (i.e., up to 27 hours) to optimize scheduling/dispatch of resources in accordance with power system needs at least cost.

The Consortium understands the reasons for this key design feature, and believes if properly designed resources will be scheduled/dispatched more efficiently compared to today's IAM. This should result in enhanced reliability of Ontario's power system, along with more efficient market-clearing prices and less uplift payments, which will lower costs to Ontario's electricity customers relative to costs borne today.

The application of PD LAP must effectively take into account operational considerations of Ontario's unique supply mix, efficiently incorporating baseload generation, variable (i.e., wind and solar) generation, quick-start and non quick-start (NQS) hydroelectric and gas-fired generation, imports, and demand-side resources. Further, the following MRP detailed design features, and some of their potential outcomes, will need to also be effectively designed and considered regarding PD LAP along with the Day-Ahead Market (DAM) and Real-Time Market (RTM) detailed design:

- New dispatch data (e.g., Minimum Energy Output, Hourly Must-Run, Minimum Daily Energy Limit, etc.) for applicable hydroelectric generators that will provide 'must-run like' status regarding scheduling and dispatch instructions, and likely implications for market-clearing prices and other MRP detailed design features (e.g., generator offer guarantee payments);

- On balance relative to today's IAM, outcomes of committing less NQS gas-fired generators, as these generators will now be evaluated on three-part offers (e.g., start-up costs, speed no-load costs, and incremental energy costs) as defined within MRP draft detailed design, therefore not committing these generators only on incremental energy offers as within today's IAM;

- Application and outcomes relating to IESO's proposed price settlement floor of $-100/MWh, and incentives this new MRP design feature may have towards some MPs changing their offer behaviour and strategies, and if so, what are the potential implications to market efficiency and power system reliability; and,

- Application and outcomes of market power mitigation, in particular economic withholding.

The Consortium recommends that IESO conduct analysis on potential scheduling/dispatch, market-clearing pricing, and settlement outcomes to 'test drive' the above MRP detailed design features – and do so prior to testing new systems based on MRP detailed design. Such analysis should be accompanied by new stakeholder engagement meetings, so MPs and stakeholders could better understand how MRP will reform today's IAM. Further, such analysis and stakeholder engagement will also inform generators and energy storage providers regarding potential MRP-related implications to their operations, contracts, rate-regulated framework, and revenues. In turn, any potential implications to operations, contracts, rate-regulated framework, and revenues could then have causal implications to MRP detailed design (and potentially amendments to IESO Market Rules).

The Consortium believes the above recommendation is prudent because any realized issues during system testing phases will be more difficult to address, and will prolong MRP implementation and increase costs to deliver the MRP project. Therefore, such analysis should be done prior to testing the new systems.

Application of Market Power Mitigation

Consistent with the Consortium's submission commenting on *Market Power Mitigation Detailed Design Issue 1.0* [2] and informed by IESO's feedback on submissions from MPs and stakeholders[3], the Consortium believes there are four main market power mitigation design features that need to be addressed.

First, the designated Constrained Areas need to be defined in more detail, so as to describe the engineering methodologies (where applicable), power system conditions, and/or IESO protocols (e.g., IESO operator actions) to derive/determine the Constrained Areas themselves. This is extremely important because the Conduct & Impact Test will only be launched by IESO if a resource(s) is determined to be located within any of the following MRP defined Constrained Areas:

- Narrow Constrained Areas (local market power) – energy;
- Dynamic Constrained Areas (local market power) – energy;
- Broad Constrained Areas (local market power) – energy;
- Province-Wide (global market power) – energy;
- Reliability Constraints (IESO operator actions) – energy;
- Reserve Area Limit (local market power) – operating reserve (OR); and,
- Province-Wide Limit (global market power) – OR.

The Consortium understands that some of the above Constrained Areas will be determined in the PD timeframe or within RTM, while others (e.g., Narrow Constrained Area) will be set well ahead of any application of the Conduct & Impact Test in DAM, PD, and/or RTM. Therefore, the Consortium recommends that IESO should establish new stakeholder engagement meetings to address: i) methodologies used to determine Constrained Areas; and, ii) conditions/protocols used to determine Constrained Areas.

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[2] See https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

[3] See October 19, 2020 located at https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

Second, regarding IESO application of assessing and potentially mitigating for physical withholding, IESO needs to provide more clarity regarding when IESO will apply a Conduct Test. Within the October 19, 2020 document where IESO provided feedback to submissions from MPs and stakeholders, IESO stated "[IESO has] limited resources to assess ex-post mitigation … may apply … conduct test … IESO has … time limit of six months to conduct such an assessment and notify … market participant of … potential settlement charge".[4]

Application of any aspect of economic or physical withholding market power mitigation and all components within the Conduct & Impact Test must be made clear and transparent. Therefore, the Consortium recommends that IESO should establish new stakeholder engagement meetings to address the application of Conduct Tests regarding potential physical withholding, including all methodologies, conditions, and protocols.

Third, regarding the derivation and application of generator specific Reference Levels to be used within the Conduct & Impact Test, the Consortium offers the following comments.

The Consortium supports the October 27, 2020 and November 3, 2020 letters submitted by the Canadian Renewable Energy Association (CanREA) to IESO providing recommendations to the application of Reference Levels for variable generators. Considering that IESO has defined a price threshold to not apply the Conduct & Impact Test when applicable energy Locational Marginal Prices (LMPs) are $25/MWh or lower (i.e., 'no-look' threshold), and based on short-run marginal costs for variable generators well below this threshold combined with contract incentives to submit offer prices between $0/MWh and offer price floors specified in the applicable IESO Market Manual, IESO should provide a 'check the box' option for variable generators to choose a pre-determined Reference Level rather than needing to submit cost information to IESO then engage in a one-on-one process to finalize Reference Levels.

Regarding hydroelectric generators, as stated within the Consortium's September 15, 2020 submission to IESO commenting on Reference Levels, because hydroelectric generators are very site specific, IESO should expect wide variation of actual costs across all hydroelectric generators. Therefore, it will take time for hydroelectric generators and IESO to establish Reference Levels – with a potential outcome of disagreements on Reference Levels resulting in potential issues relating to IESO's ability to make final decisions on Reference Levels and what recourse hydroelectric generators may have if disputes arise.

Fourth, as stated within the Consortium's submission *Market Power Mitigation Detailed Design Issue 1.0*, if incremental imports are to be the framework to assess and mitigate global market power, this framework needs to be expanded to include all of Ontario's interconnections. However, based on IESO's October 19, 2020 feedback, only interconnections from New York and Michigan are to be included within

[4] See p. 24 within IESO feedback dated October 19, 2020, located at https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

[redacted]

the global market power mitigation framework, as these interconnections to Ontario comprise part of wholesale electricity markets in the U.S. (i.e., NYISO and MISO).

The Consortium continues to not understand this rationale, considering the significant volumes of import supply from Quebec relative the import supply from New York (through NYISO) and Michigan (through MISO). For example, the following data from 2019 imports into Ontario clearly show the importance to test for global market power over the Ontario-Quebec interconnections.

- Total imports from all Ontario interconnections (Quebec, Manitoba, Minnesota, Michigan, and New York) was 6.6 TWh
- Total imports from Quebec to Ontario was 5.9 TWh, most of these Quebec imports were delivered though the Outaouais interconnection accounting for 4.8 TWh
- Nearly 90% of import into Ontario were supplied from Quebec, and nearly 75% of supply from Quebec was delivered through the Outaouais interconnection

Considering the significant majority of supply from imports into Ontario have been through the Ontario-Quebec interconnections, it is very clear that these imports should also be subject to market power mitigation.

Market-Clearing Prices Should Best Reflect Shortage/Scarcity Conditions

As the Consortium recommended in our submission commenting on the draft *Offers, Bids and Data Inputs Detailed Design Issue 1.0*, and re-iterated within our submissions commenting on the draft *DAM Calculation Engine Detailed Design Issue 1.0* and the draft *Real-Time Calculation Engine Detailed Design Issue 1.0* [5], IESO should commit to shortage/scarcity pricing in MRP design and rules to accurately value energy and OR.

Over the last several years, shortage/scarcity pricing design and rule changes have been implemented within the U.S. wholesale electricity markets in order to improve price fidelity and market efficiency. Appendix A lists the shortage/scarcity pricing design from all U.S. wholesale electricity markets.

Further, when market-clearing prices are inefficiently suppressed (e.g., due to design components, rules, IESO interventions (e.g., applicable of control actions, etc.), etc.), revenue adequacy concerns increase. That is, market-clearing prices that best reflect shortage/scarcity conditions result in needed and justified inframarginal rents contributing to fixed cost recovery for generators and other resources. To the extent that market-clearing prices do not accurately reflect shortage/scarcity conditions, mechanisms such as offer guarantee and make-whole payments will be increasingly needed. Since these additional payments

[5] See https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement for these three submissions

will be required when market-clearing prices do not sufficiently reflect shortage/scarcity conditions, these costs accrue to uplifts which lessen efficiency and transparency within the wholesale market.

Additional to the need for offer guarantee and make-whole payments, resource adequacy mechanisms (e.g., Capacity Auctions, contracts) will also be required to ensure continued operations of needed generators and other resources, as well as sufficient revenues to ensure development of needed new generation projects and other resources.

Therefore, now that all draft MRP detailed design documents relating to the DAM, PD, and RTM calculation engines have been reviewed, the Consortium recommends that IESO should schedule new stakeholder engagement meetings to go through examples of multiple scenarios how the calculation engines will derive LMPs for energy and OR, including potential implications for the application of offer guarantee and make-whole payments. After MPs, stakeholders, and IESO discuss and review these examples, LMPs could then be better assessed whether they are best reflecting shortage/scarcity power system conditions.

Negative Pricing and Proposed Price Settlement Floor

As predominantly discussed within the Consortium's submission commenting on the draft *DAM Calculation Engine Detailed Design Issue 1.0*, where IESO first revealed a proposed price settlement floor of $-100/MWh for energy, the Consortium continues to believe that negative pricing will impact IAM post implementation of MRP. We believe this will be the case relatively more so within some sub-zones within the Northeast and Northwest zones, due to projected demand/supply balance and supply mix comprised of many baseload and low marginal cost generators.

In the Consortium's opinion, IESO's proposed $-100/MWh energy price settlement floor may result (and actually incentivize) in some generators offering prices between $-101/MWh and $-2,000/MWh resulting from:

- No risks to setting LMPs lower than $-100/MWh; and,
- 'Out of market' drivers (e.g., contract provisions, regulated framework, water management, etc.) may incentivize offer prices less than $-100/MWh to best ensure being scheduled for RT dispatch.

Consequential to potential changes in offer behaviour and strategies from some generators, under circumstances of Surplus Baseload Generation (SBG) in some sub-zones within the Northeast and Northwest zones, IESO will need to make decisions on which generators will be dispatched to produce energy and which generators will be economically curtailed so as to not produce energy. This potential dynamic and outcome continues to not be contemplated within any of the draft MRP detailed design documents.

IESO's October 19, 2020 feedback stated that the "rationale for the settlement floor price at $-100/MWh was provided at MRP Calculation Engine Technical Session on August 27, 2020. The presentation and recording are available for review on the Energy Detailed Design Stakeholder engagement page".[6] This IESO response represents very limited feedback to negative pricing and SBG issues raised by the Consortium through multiple submissions, as well as questions and concerns raised by other MPs and stakeholders within their submissions or within IESO stakeholder engagement meetings this year.

The Consortium recommends new and specific stakeholder engagement meetings to address remaining questions and continued concerns over the proposed price settlement floor and potential implications to the efficiency of the IAM and impacts to applicable MPs.

GOVERNANCE, DECISION-MAKING, AND RECOURSE WITHIN IAM

As stated within the Consortium's submission commenting on *Market Power Mitigation Detailed Design Issue 1.0* and the submission commenting on the draft Incremental Capacity Auction High-Level Design[7], the Consortium was pleased that IESO launched the Advisory Group on Governance and Decision-Making[8] a few years ago, based on suggestions from MPs and stakeholders that the governance, decision-making, and recourse framework within IAM requires reform. And the Consortium applauds IESO for accepting then implementing the recommendations from this Advisory Group.

However, the Consortium's support was also contingent on IESO's scope of review of the governance, decision-making, and recourse framework within IAM through the Advisory Group. That is, IESO had determined that review of the roles and responsibilities of the Ontario Energy Board (OEB) regarding oversight over design changes within the IAM or amendments to the IESO Market Rules were out of scope. Also, out of scope was review of the IESO Board of Directors' statutory authority to make rules and amend the IESO Market Rules. Considering these IESO imposed consultation parameters, the Consortium generally supported the recommendations and accompanying implementation plan for reforms[9] but believes further reforms will be needed – especially considering many of the design components within the MRP draft detailed design market power mitigation framework.

As identified in the Consortium's February 20, 2018 and December 1, 2017 submissions to IESO[10], the framework for governance, decision-making, and recourse within other wholesale electricity markets provides MPs and stakeholders with more robust input and/or decision-making authority regarding market design changes and rule amendments, as well as regulatory oversight and recourse. Regarding

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[6] See p. 50 within IESO feedback dated October 19, 2020, located at https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

[7] See https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Incremental-Capacity-Auction

[8] See https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/IESO-Governance-and-Decision-Making

[9] See Report and Implementation Plan at http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/IESO-Governance-and-Decision-Making

[10] Both submissions are located at http://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Working-Group

regulatory oversight, for all U.S. jurisdictions under the Federal Energy Regulatory Commission's (FERC's) authority[11], FERC has oversight regarding wholesale market rules or their equivalent[12]. Therefore, specifically for market power mitigation, all design changes and rule amendments are ultimately decided by FERC through transparent and inclusive regulatory proceedings. Further, any MP or stakeholder have recourse through the ability to make representations within FERC proceedings.

It is important to note that the Government of Alberta (GOA) made changes to the governance, decision-making, and recourse regarding Alberta's wholesale electricity market in 2018, by granting the Alberta Utilities Commission (AUC) with regulatory oversight over this market (i.e., ISO Rules)[13]. This change was made in acknowledgement that the Alberta Electricity System Operator's (AESO's) planned Capacity Market would have introduced AESO-made decisions that will drive investment decisions within Alberta (e.g., target capacity, Demand Curve, market power mitigation, etc.).

Prior to the GOA abandoning the Capacity Market in 2019, the AESO filed amendments to the ISO Rules with AUC on January 31, 2019, launching an oral proceeding with timelines for AUC to render decisions by July 31, 2019. It was clear based on the large number of intervenors and filed evidence that AESO's decision to design and implement a Capacity Market was very contentious[14]. The Consortium believes that this AUC proceeding was a very good example of why such regulatory oversight is important.

Considering the impactful nature of the MRP detailed design for market power mitigation, specifically its components that will drive economics within IAM and for mitigated MPs, governance, decision-making, and recourse within IAM needs to be revisited. For example, establishing Reference Levels for some MPs may prove to be very contentious. Under the present governance, decision-making, and recourse framework within IAM, IESO has ability to make final decisions on facility-specific Reference Levels. Further, considering that the actual facility-specific Reference Levels will not be included within the IESO Market Rules, if applicable MPs do not agree with their IESO determined Reference Levels, there is no formal recourse framework to OEB. Therefore, the only recourse for MPs under this example is the dispute resolution framework as described within the IESO Market Rules or legal action outside of the governance of IAM.

Another example is IESO's present position of not including the Ontario-Quebec interconnections within the global market power mitigation framework, even though it is abundantly clear that very few MPs may

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[11] FERC has jurisdictional oversight on ISO-NE, NYISO, PJM, MISO, SPP, and CAISO. FERC does not have any jurisdictional oversight on ERCOT

[12] Equivalency to market rules are embodied within specific Tariffs and/or Operating Agreements, but these are the rules that govern their respective wholesale electricity market

[13] On June 11, 2018, the Alberta Legislature passed Bill 13, *An Act to Secure Alberta's Electricity Future*, available here: http://www.assembly.ab.ca/net/index.aspx?p=bills_status&selectbill=013&legl=29&session=4

[14] AUC proceeding homepage is available here: https://www2.auc.ab.ca/Proceeding23757/SitePages/Home.aspx. A list of intervenors can be found here: https://www2.auc.ab.ca/Proceeding23757/SitePages/ViewRegisteredParties.aspx. Filed evidence is available here: https://www2.auc.ab.ca/Proceeding23757/ProceedingDocuments/Forms/AllItems.aspx.

that typically import supply from Quebec have the ability to exercise market power based on concentration ratios used within economics to determine the potential ability to exercise market power.

Therefore, to further review and propose changes to the governance, decision-making, and recourse framework within IAM, the Consortium recommends that IESO either re-launch the Advisory Group on Governance and Decision-Making or launch a new stakeholder engagement initiative (potentially through the planned launch of a new IESO stakeholder body tentatively named the Stakeholder Planning and Priorities Advisory Group[15]).

ADDITIONAL STAKEHOLDER ENGAGEMENT MEETINGS

Based on the points made in the above sections of this submission, it is clear that new stakeholder engagement meetings are required – and these should be additional to the regular MRP update meetings that have been taking place at the end of each month.

Listed below is a compilation of the Consortium's proposed additional MRP related stakeholder engagement meetings that IESO should plan for within 2021:

- Design and application of new dispatch data for applicable hydroelectric generators (the Consortium acknowledges that meetings between IESO and some hydroelectric generators are on-going, but recommend these discussions to be formalized through a transparent stakeholder engagement initiative);
- Analysis and review of results of potential scheduling, dispatch, pricing and price-setting, and settlements of the calculation engines for DAM, PD, and RTM, including clear application and outcomes of potential to best ensure shortage/scarcity pricing for energy and OR;
- Design and application of these features of market power mitigation:
    - Methodologies, power system conditions, and protocols to determine Constrained Areas;
    - More definitive application of Conduct Test to assess for physical withholding; and,
    - Determination of Reference Levels and Quantities (the Consortium acknowledges IESO has been having, and will continue to have, meetings with MPs and stakeholders on this design feature);
- Design and application of proposed $-100/MWh price settlement floor, including potential implications of and for negative pricing and SBG regarding generator operations, market efficiency, and power system reliability; and,

[15] See Agenda Item #7 – Stakeholder Engagement Framework: Phase II, November 3, 2020 IESO Stakeholder Advisory Council (SAC) meeting, located at https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Stakeholder-Advisory-Committee/Meetings-and-Materials

- Review existing framework of governance, decision-making, and recourse within IAM, keeping in mind MRP detailed design, including any additional implications (e.g., contract amendments, etc.).

CONTRACT AMENDMENTS RELATED TO MRP IMPLEMENTATION

In general, the Consortium has not raised MRP-related contract amendment points and concerns during IESO MRP stakeholder engagement meetings, in order to respect the scope of those meetings.

The Consortium acknowledges and applauds IESO for engaging with contract counterparties beginning as far back as a few years ago despite MRP's planned 2023 implementation. To date, meetings between the Consortium, and individual members of the Consortium, and IESO Contract Management have been helpful and productive.

Considering the stage of development within the MRP project, and the first batch of MRP-related amendments to the IESO Market Rules[16] have been released for comments from MPs and stakeholders, the Consortium believes now is the time to raise general MRP-related contract amendment implications within MRP stakeholder engagement.

There are two aspects regarding the inter-connectiveness of IAM design and rules (i.e., MRP detailed design and amendments to IESO Market Rules), and contracts regarding drivers how generators participate within IAM along with applicable contract amendment provisions.

First, as stated within this submission and other Consortium submissions, some features within MRP draft detailed design have potential to impact how generators may alter their offer behaviour and strategies in combination with applicable contract drivers (including potential MRP-related contract amendments). The end result for generator total revenues (i.e., IAM and contract revenues), total costs to customers (i.e., wholesale energy prices, uplift, and Global Adjustment), efficiency within IAM, and potentially power system reliability could all be impacted, either positively, negatively, or even both (resulting in trade-offs) – depending on the interplay between MRP design/rules and contract provisions (including MRP-related contract amendments). Therefore, the Consortium recommends that much more attention and specific stakeholder engagement is required to better assess the interplay of MRP design/rules and MRP-related contract amendments towards finalizing MRP detailed design and amendments to the IESO Market Rules.

Second, potential MRP-related contract amendment provisions need to assess a broader view of the totality of Ontario's wholesale electricity market to which contracts are a significant part. That is, all generator contracts held with IESO were designed and executed well before the MRP project started in 2016. Therefore, the design of some contracts, including specific provisions, were developed within a much different context of IAM design and rules. Therefore, the Consortium recommends that any MRP-related contract amendments not be unnecessarily and inefficiently confined, so as to potentially not

[16] See https://www.ieso.ca/Market-Renewal/Stakeholder-Engagements/Implementation-Engagement-Market-Rules-and-Market-Manuals

[redacted]

achieve fairness to generators and/or inadvertently creating inefficiencies within IAM post MRP implementation which could lead to higher costs to customers.

There are a few practical examples of the above points relating to IAM design/rules and the interplay of contracts.

Within the design and rules of IAM leading to the opening of Ontario's wholesale electricity market in May 2002, hundreds of megawatts of gas-fired Non-Utility Generators (NUGs) were under contract with the Ontario Electricity Financial Corporation (OEFC), and based on being transmission-connected these NUGs were required to participate within IAM. Based on the Power Purchase Agreements (PPAs) these NUGs held with OEFC, IESO worked with MPs and stakeholders to design and create rules for these NUGs, resulting in creating a specific classification of generators within IAM – Transitional Scheduling Generators (TSGs). TSGs were afforded specific design and rules within IAM, mainly as a form of self-scheduling generators. Post market opening, issues that were not properly considering prior to market opening arose through TSGs not complying with their submitted production schedules[17]. Therefore, IESO had to then specifically engage with MPs and stakeholders to make IAM design changes and amendments to the IESO Market Rules.

The above points are a clear Ontario-specific example of the acknowledgement of incorporating NUGs within IAM design and rules, but not enough attention during the initial IAM design stage to efficiently incorporate aspects of the PPAs. However, within the existing generator contracts held with IESO today (i.e., not including NUG PPAs), provisions permit contract amendments which will specifically address MRP-related amendments to the IESO Market Rules. Therefore, IESO has a broad ability to ensure both MRP design/rule amendments can work seamlessly with MRP-related contract amendments, and vice-versa, to best ensure effective outcomes for generators, cost effectiveness for customers, efficiency within IAM, and power system reliability.

Another example of the interplay of wholesale electricity market design/rules and 'out of market' mechanisms, such as contracts, exists within the Capacity Markets within ISO-NE, PJM, and NYISO.

The Capacity Markets in ISO-NE, PJM, and NYISO were implemented shortly after opening their wholesale electricity markets in the late 1990s and early 2000s. From the outset, these Capacity Markets did not have to address significant quantities of generation projects being procured through government or utility contracts because of the 'merchant boom' that developed significant amounts of coal-fired and gas-fired generator projects in the 1990s and early 2000s. However, due to the increasing amount of generation projects (mainly renewable generation projects) that have been developed over the past several years through government or utility contracts, ISO-NE, PJM, and NYISO were forced to make design/rule changes to their respective wholesale markets to address issues resulting from these

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[17] IESO now defunct Market Pricing Working Group had identified issue #011 – Comparing Treatment of Self-Scheduling Resources in Pre-Dispatch and Real-Time, to which IESO made subsequent changes to help improve self-scheduling generator compliance with production schedules, as deviations to production schedules were impacting market-clearing prices

[redacted]

contracted generators. Therefore, ISO-NE and PJM implemented Minimum Offer Pricing Rules (MOPRs) and NYISO implemented buy-side mitigation (BSM)[18] rules within their respective Capacity Markets[19]. In general, MOPRs and BSM were design changes and rule amendments attempting to clear Capacity Market prices at levels indicating system capacity needs and affording sufficient revenues for incumbent generators to continue helping to maintain respective resource adequacy requirements in these jurisdictions.

The examples from ISO-NE, PJM, and NYISO clearly indicate that initially specific market design features and rules were not required. However, as their markets underwent significant supply changes (i.e., government and utility contracts for renewable generators), specific design features and rules, such as MOPRs and BSM, were implemented to address market efficiency and power system reliability issues.

The above example of the implementation of MOPRs and BSM within the Capacity Markets within ISO-NE, PJM, and NYISO are fully analogous to why more MRP design attention needs to be focused on the integration of generator contracts and rate-regulated generators within IAM.

The Consortium will be happy to discuss the contents of this submission with you at a mutually convenient time.

Sincerely,

Jason Chee-Aloy
Managing Director

[18] See https://www.nyiso.com/documents/20142/8363446/BSM-Overview.pdf/7b22b74e-c69e-dfa5-ec62-adbc23b6a4e4 for an overview of BSM rules within NYISO. The overarching rationale for NYISO's implementation of BSM rules is to mitigate market effects of MP conduct that could substantially distort competitive outcomes and to avoid unnecessary interference with competitive price signals. This rationale is in-line and consistent with the rationale in this submission regarding the need to mitigate for predatory pricing and price suppression within the IAM.

[19] While IESO plans to administer the first Capacity Auction (CA) in December 2020, IESO administered CAs differ in many aspects to the Capacity Markets in NYISO, ISO-NE, and PJM. One relevant difference, in context of this submission, is that CAs will not require participation of all capacity resources in Ontario. Therefore, contracted and rate-regulated generation will not participate in CAs. Within the NYISO, ISO-NE, and PJM Capacity Markets, all capacity resources participate – even if they have 'out of market' contracts or regulated rates. Therefore, MOPR and BSM rules have been implemented in these Capacity Markets, and are not being planned for within the CAs.

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APPENDIX A – SHORTAGE/SCARCITY PRICING WITHIN U.S. WHOLESALE ELECTRICITY MARKETS

Shortage/Scarcity Pricing Mechanisms

Market	Shortage/ Scarcity Pricing Mechanisms	Description of Pricing Mechanism	Implementation Date
ISO-NE	Single step Operational Reserve Demand Curve (ORDC) with additive penalty factors		
	Local 30-Minute Operating Reserve (TMOR)	• $250/MWh shortage pricing value	Late 2006
	System 30-Minute Operating Reserve (TMOR)	• Minimum TMOR $1,000/MWh shortage pricing value • Replacement Reserve $250/MWh shortage pricing value o Does not cascade with other reserve shortage prices	
	System 10-Minute Non-synchronized Reserve (TMNSR)	• $1,500/MWh shortage pricing value	
	System 10-Minute Spinning Reserve (TMSR)	• $50/MWh shortage pricing value	
	Regulation shortages	• $100/MWh	
	Pay-for-Performance (PFP)	• Feature of the Forward Capacity Market which provides incentives for resources that perform during capacity scarcity conditions. • Elements include: o Determination of resource performance scores based on actual energy and reserves provided during scarcity conditions o Payment or charges calculated for resources based on performance scores o Stop-loss mechanism to prevent unlimited risk to resource owners for poor performance o Eligibility for performance payments for resources without capacity supply obligations • $2,00/MWh, increasing to $5,455/MWh in 2024	June 1, 2018

Market	Shortage/ Scarcity Pricing Mechanisms	Description of Pricing Mechanism	Implementation Date
PJM	Stepped Operational Reserve Demand Curve with additive penalty factors		
	30-Minute Reserve Requirement (Day-Ahead)	• Step 1: $850/MWh for 1.5*largest contingency • Step 2: Step 1 + $300/MWh	2006
	10-Minute Sync Reserve Requirement (Real-Time)	• Step 1: $850/MWh for largest contingency • Step 2: Step 1 + $300/MWh	
	Primary Reserve Requirement (Real-Time)	• Step 1: $850/MWh for largest contingency • Step 2: Step 1 + $300/MWh	
	Regulation Shortages	• $100/MWh	
	Pay-for-Performance	• Resources must deliver on demand during system shortages or owe payment for non-performance. • Incentive rate for 2019/2020 was ~$2,420/MWh	2017
NYISO	Stepped Operational Reserve Demand Curve		
	30 Minute Total Reserves	• NYCA o 300 MW at $25/MWh o 355 MW at $100/MWh o 300 MW at $200/MWh o 1,665 MW at $750/MWh • EAST, NYC, LI o $25/MWh • SENY o 250 or 500 MW at $25/MWh o 1,300 MW at $500/MWh	2005
	10 Minute Total Reserves	• NYCA o $750/MWh • EAST o $775/MWh • NYC, LI o $25/MWh	
	10 Minute Spin	• NYCA o $775/MWh • EAST o $25/MWh	

Market	Shortage/ Scarcity Pricing Mechanisms	Description of Pricing Mechanism	Implementation Date
MISO	Stepped Operational Reserve Demand Curve with additive penalty factors		
	Spinning Reserve	• $65/MWh for shortages 0% to 10% of market-wide requirement • $98/MWh	2009
	Non-Spinning Reserve	• $3,500/MWh (VOLL) minus monthly demand curve price for regulation • $1,100 for 4% to 96% of market-wide requirement • $200/MWh for >96% of market-wide requirement	
ERCOT	Fixed penalty factor	• $9,000/MWh up to contingency reserve level ad downward sloping curve thereafter based on the probability of reserves falling below contingency level	2010
SPP	Stepped Operational Reserve Demand Curve		
	10-Minute Spinning Reserve 10-Minute Non-Synchronous Reserves	• $275/MWh for >/= 25% of second largest projected resources max normal operating capacity • $550/MWh for 25% to 50% of second largest projected resources max normal operating capacity • $1,100/MWh for >50% of second largest projected resources max normal operating capacity	Pre-2010
	Spinning Reserve	• Uses violation relaxation limit (VRL) of $200/MWh	
CAISO	Stepped Operational Reserve Demand Curve		
	10-Minute Spinning Reserves	• Calculated as percentage of bid price • Maximum reserve shadow price is 100% of energy bid price, capped at $1,000/MWh	Pre-2006
	10-Minute Non-Spinning Reserves		

[redacted]

Shortage/Scarcity Pricing Conditions

Market	Conditions in Place for Shortage Pricing to Occur	Shortage/ Scarcity Pricing Mechanisms	Description of Pricing Mechanism	Implementation Date
ISO-NE	• System contingencies of transmission facilities or generators	Single step Operational Reserve Demand Curve (ORDC) with additive penalty factors		
		Local 30-Minute Operating Reserve (TMOR)	• $250/MWh shortage pricing value	Late 2006
		System 30-Minute Operating Reserve (TMOR)	• Minimum TMOR $1,000/MWh shortage pricing value • Replacement Reserve $250/MWh shortage pricing value o Does not cascade with other reserve shortage prices	
		System 10-Minute Non-synchronized Reserve (TMNSR)	• $1,500/MWh shortage pricing value	
		System 10-Minute Spinning Reserve (TMSR)	• $50/MWh shortage pricing value	
		Regulation shortages	• $100/MWh	
		Pay-for-Performance (PFP)	• Feature of the Forward Capacity Market which provides incentives for resources that perform during capacity scarcity conditions. • Elements include: o Determination of resource performance scores based on actual energy and reserves provided during scarcity conditions o Payment or charges calculated for resources based on performance scores o Stop-loss mechanism to prevent unlimited risk to resource owners for poor performance o Eligibility for performance payments for resources without capacity supply obligations • $2,00/MWh, increasing to $5,455/MWh in 2024	June 1, 2018

<table>
<tr><th>Market</th><th>Conditions in Place for Shortage Pricing to Occur</th><th>Shortage/ Scarcity Pricing Mechanisms</th><th>Description of Pricing Mechanism</th><th>Implementation Date</th></tr>
<tr><td rowspan="7">PJM</td><td rowspan="7">• Amount of available reserves dips below the reserve requirement
o Available Synchronized Reserve MW<Synchronized Reserve Requirement
o Available Primary Reserve MW<Primary Reserve Requirement
• Voltage reduction action or manual load shed action is initiated</td><td colspan="3">Stepped Operational Reserve Demand Curve with additive penalty factors</td></tr>
<tr><td>30-Minute Reserve Requirement (Day-Ahead)</td><td>• Step 1: $850/MWh for 1.5*largest contingency
• Step 2: Step 1 + $300/MWh</td><td rowspan="4">2006</td></tr>
<tr><td>10-Minute Sync Reserve Requirement (Real-Time)</td><td>• Step 1: $850/MWh for largest contingency
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<tr><td>Regulation Shortages</td><td>• $100/MWh</td></tr>
<tr><td>Pay-for-Performance</td><td>• Resources must deliver on demand during system shortages or owe payment for non-performance.
• Incentive rate for 2019/2020 was ~$2,420/MWh</td><td>2017</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td rowspan="4">NYISO</td><td rowspan="4">• When the system runs short of Regulation Service Capacity or any Operation Reserve product requirement.
• If the cost to procure Regulation Service Capacity or Operation Reserve exceeds the shortage pricing values establish by the demand curves.</td><td colspan="3">Stepped Operational Reserve Demand Curve</td></tr>
<tr><td>30 Minute Total Reserves</td><td>• NYCA
o 300 MW at $25/MWh
o 355 MW at $100/MWh
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o $775/MWh
• EAST
o $25/MWh</td></tr>
<tr><td></td><td></td><td colspan="3"></td></tr>
</table>

Market	Conditions in Place for Shortage Pricing to Occur	Shortage/ Scarcity Pricing Mechanisms	Description of Pricing Mechanism	Implementation Date
MISO	• When demand requirements plus reserves exceed available supply plus reserve margin.	Stepped Operational Reserve Demand Curve with additive penalty factors		2009
		Spinning Reserve	• $65/MWh for shortages 0% to 10% of market-wide requirement • $98/MWh	
		Non-Spinning Reserve	• $3,500/MWh (VOLL) minus monthly demand curve price for regulation • $1,100 for 4% to 96% of market-wide requirement • $200/MWh for >96% of market-wide requirement	
ERCOT	• Supply is short of demand	Fixed penalty factor	• $9,000/MWh up to contingency reserve level ad downward sloping curve thereafter based on the probability of reserves falling below contingency level	2010
SPP	• Supply is short of demand	Stepped Operational Reserve Demand Curve		Pre-2010
		10-Minute Spinning Reserve 10-Minute Non-Synchronous Reserves	• $275/MWh for >/= 25% of second largest projected resources max normal operating capacity • $550/MWh for 25% to 50% of second largest projected resources max normal operating capacity • $1,100/MWh for >50% of second largest projected resources max normal operating capacity	
		Spinning Reserve	• Uses violation relaxation limit (VRL) of $200/MWh	
CAISO	• Supply is insufficient to meet minimum procurement requirements for Regulation Down, Non-Spinning Reserves, Spinning Reserve and Regulation Up	Stepped Operational Reserve Demand Curve		
		10-Minute Spinning Reserves	• Calculated as percentage of bid price • Maximum reserve shadow price is 100% of energy bid price, capped at $1,000/MWh	Pre-2006
		10-Minute Non-Spinning Reserves		

Shortage/Scarcity Pricing Changes

ISO/RTO	Proposed Change	Max Shortage Price
ISO-NE	ORDC curve based on value of lost load (VOLL) and probability of losing reserves	• VOLL of $30,000/MWh • Probability calculation based on forced generator outages
MISO	ORDC curve based on value of lost load (VOLL) and probability of losing reserves	• VOLL of $12,000/MWh • Probability calculation based on forced generator outages, load forecast error and scheduled interchange error
PJM	Recently FERC approved, Fixed penalty factor of $2,000/MWh up to minimum reserve requirements (MRR) and downward sloping curve thereafter based on probability of reserves falling below MRR	• $2,000/MWh • Max cascaded reserve price of $12,000/MWh
CAISO	Proposal pending at FERC to modify the max energy bid price to $2,000/MWh from $1,000/MWh	• Bid cap of $2,000/MWh • Revise the max reserve shadow price to $2,000/MWh